Interconnection Process Enhancements

Revised Straw Proposal For Topics 3-5 and 12-15

November 8, 2013

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Interconnection Process Enhancements

Revised Straw Proposal Paper for Topics 3-5 and 12-15

1 Executive summary

The Interconnection Process Enhancements ("IPE") initiative is the latest in a series of stakeholder processes that the ISO has conducted over the past several years to continuously review and improve its generation interconnection procedures ("GIP") and associated interconnection agreements.[1]

The ISO launched the IPE initiative with the issuance of a scoping proposal paper on April 8. The scoping proposal accomplished two steps: first, it assembled a comprehensive list of potential GIP-related topics for consideration in this initiative; and second, it selected twelve topics from the comprehensive list of topics for proposed inclusion in the scope of the IPE initiative.

Based on stakeholder feedback on the April 8 scoping proposal, the ISO added additional topics to the scope of the IPE initiative and posted an issue paper on June 3 addressing the expanded scope of fifteen topics. While the June 3 issue paper was a conventional issue paper for some of the fifteen topics in scope, it served as a straw proposal paper on others. Specifically, for the seven topics addressing queue management issues (*i.e.*, topics 6-12[2]), the ISO offered straw proposals in the June 3 paper. For the remaining eight topics (*i.e.*, topics 1-5[3] and 13-15[4]), the ISO was not yet prepared to offer a proposal in the June 3 issue paper and instead provided further analysis of the issues and suggested potential ideas and options for stakeholder consideration.

Following publication of the June 3 issue paper and receipt of stakeholder comments, the ISO posted a draft final proposal for topics 6-12 on July 2. The ISO took the proposals for topics 6-11 to

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[1] Technically the "GIP" refers to Appendix Y of the ISO tariff, which governs the interconnection procedures for large generators submitted in the transition cluster up to and including Cluster 4. In the context of IPE, however, the ISO is using the acronym "GIP" as an umbrella term to refer more generally to the ISO's interconnection procedures for all generation projects in Cluster 4 and earlier that are connecting to the ISO grid, except where specified otherwise.

[2] These seven topics are: (6) provide for ability to charge customer for costs for processing a material modification request; (7) COD modification provision for SGIP projects; (8) length of time in queue provision for SGIP projects; (9) clarify that PTO not ISO tenders GIA; (10) timeline for tendering draft GIAs; (11) LGIA negotiations timeline; and, (12) consistency of suspension definition between serial and cluster.

[3] These five topics are: (1) future downsizing policy; (2) disconnection of completed phase(s) of project due to failure to complete subsequent phase; (3) clarify tariff and GIA provisions related to dividing up GIAs into multiple phases; (4) improve the Independent Study Process; and, (5) improve the Fast Track Process.

[4] These three topics are: (13) clarification of timing of transmission cost reimbursement; (14) distribution of forfeited funds; and, (15) material modification review (formerly "transformer/inverter changes").

the September meeting of the ISO Board, received Board approval, and filed the associated tariff amendments on September 30, 2013 with the Federal Energy Regulatory Commission in Docket No. ER13-2482. As a result, topics 6-11 are not addressed in this straw proposal paper; however, topic 12 has been carried over and included in the present paper.

On July 18, the ISO published a straw proposal paper addressing topics 1-5 and 13-15. The July 18 paper offered straw proposals for topics 1, 2, and 3. The ISO also offered a straw proposal for topic 15 (called "inverter/transformer changes" at the time, but now called "material modification review"); implementation of the proposal for topic 15 will be through the business practice manual change process rather than through tariff changes. The ISO was not prepared to offer straw proposals in the July 18 paper for topics 4, 5, 13, and 14; nevertheless, the discussion of these four topics provided additional analysis and, for some, offered options for stakeholder consideration (*e.g.,* topics 13 and 14).

On September 12, the ISO published a draft final proposal for topics 1 and 2. After receiving stakeholder feedback, the ISO made further refinements and modifications to the draft final proposal which it published in a series of addendums – the first on September 24 and the second on October 21. The ISO will present its proposals for topics 1 and 2 to the ISO Board for approval at its November 7 meeting.

Thus, the remaining topics in the IPE initiative are 3-5 and 12-15 and these topics are the subject of this paper. Proposals for the subset of these topics requiring tariff amendments (*i.e.,* topics 4, 5, 13, and 14) will be presented to the ISO Board for approval at its March 2014 meeting.

2 Introduction

California's ambitious renewable portfolio standards and environmental goals have resulted in significant development of new generation projects in recent years, especially new renewable solar and wind projects. The majority of these projects request interconnection to facilities under the operational control of the ISO.[5] For projects that entered the ISO queue prior to 2012 (i.e., up to and including Cluster 4), interconnection to the ISO controlled grid is governed by the tariff provisions encompassed by the ISO's generator interconnection procedures ("GIP").[6] Successful

[5] Some projects request interconnection to the distribution systems of the participating transmission owners through their wholesale distribution access tariff ("WDAT").

[6] For projects entering the ISO queue in 2012 or later (i.e., starting with ISO queue Cluster 5), interconnection to the ISO grid is governed by the new Generator Interconnection and Deliverability Allocation Procedures ("GIDAP") approved by FERC in 2012. The present IPE initiative is intended to focus primarily on the rules governing projects in cluster 4 and earlier, as the ISO is now only partway through the first implementation cycle of the GIDAP and is not yet ready to consider changes to the GIDAP. In the event that a proposed enhancement to the GIP under this initiative appears to be appropriate to extend to the GIDAP, the ISO will consider whether extension of the enhancement to

completion of the interconnection process is a necessary step in the development of a new generation project and is but one of the many challenges faced by generation developers.

The ISO is committed to continuously reviewing potential enhancements to its GIP to reflect changes in the industry and to better accommodate the needs of interconnection customers. As a demonstration of this commitment, the ISO has conducted a series of stakeholder processes over the past several years to improve the GIP. These include Generation Interconnection Process Reform ("GIPR") held in 2008-09, Generation Interconnection Procedures Phase 1 ("GIP 1") in 2010, Generation Interconnection Procedures Phase 2 ("GIP 2") in 2011, and Generation Interconnection Procedures Phase 3 ("GIP 3") in 2012[7].

The ISO launched the latest in this series of stakeholder processes to review and improve the GIP when it published the Interconnection Process Enhancements initiative ("IPE") scoping proposal on April 8.[8] Rather than the usual sequence of beginning an initiative with an issue paper, the ISO identified the development of a scoping proposal as a necessary first step. Its purpose was twofold. First, it assembled a comprehensive list of potential topics in one place from a number of sources including:

- During the course of the GIP 3 stakeholder process a list of twenty-seven potential topics (including generator project downsizing) were compiled for consideration;
- Outside of the GIP 3 stakeholder process, individual stakeholders suggested GIP-related topics to the ISO;
- At the September 2012 ISO Board of Governors meeting, ISO Management committed to include two topics in the scope of this initiative in response to stakeholder interest: (1) future generator project downsizing policy, and (2) disconnection of an initial project phase of a generation project for failure of the project to complete a subsequent phase; and,
- An ISO need to improve the queue management process.

GIDAP would have any unintended consequences on the GIDAP, and if not we would support such extension. The present initiative is not intended, however, to entertain changes specifically targeted to the GIDAP.

[7] GIP 3 was started in early 2012 but later deferred while the generator project downsizing initiative was pursued. In GIP 3 the ISO solicited stakeholder comments on the relative priority of issues that should be considered, on generator project downsizing as well as on a couple dozen other topics. The ISO explained that a limited number of topics would be included in the initial stakeholder effort to ensure timely resolution and implementation. Stakeholders expressed broad support for only one topic, the extent to which an interconnection customer could downsize the MW capacity of its proposed generating facility and retain its queue position (i.e., generator project downsizing). As a result of this stakeholder feedback, the ISO deferred work on the other topics that did not receive such broad support and focused efforts on generator project downsizing through a separate stakeholder initiative.

[8] http://www.caiso.com/Documents/ScopingProposal-InterconnectionProcessEnhancements.pdf

Second, the scoping proposal selected a set of potential GIP-related topics from the comprehensive list of topics mentioned above for proposed inclusion in the scope of the IPE initiative. This was necessary because the comprehensive list of topics (nearly fifty topics in total) represented a far larger set of topics than could be reasonably addressed within the scope of this initiative. To develop a subset of topics representing a more reasonable workload to include in the scope of this initiative, the ISO took into consideration the estimated the level of effort and relative priority associated with each topic as well as its contribution to queue management efforts. This resulted in twelve topics that the ISO proposed in the April 8 scoping proposal for inclusion in the scope of the IPE initiative. Based on stakeholder feedback received following the release of the April 8 scoping proposal, the ISO expanded the scope of the IPE initiative by three topics and posted an issue paper on June 3 addressing the resulting scope of fifteen topics. [9]

Table 1 lists these fifteen topics.

Table 1 – Scope of topics in the June 3 issue paper

Topic No.	Topic Description
1	Future downsizing policy
2	Disconnection of first phase of project for failure of second phase
3	Clarify tariff and GIA provisions related to dividing up GIAs into multiple phases or generating projects
4	Improve the Independent Study Process
5	Improve the Fast Track Process
6	Provide for ability to charge customer for costs for processing a material modification request
7	COD modification provision for SGIP projects
8	Length of time in queue provision for SGIP projects
9	Clarify that PTO and not ISO tenders GIA
10	Timeline for tendering draft interconnection agreements
11	LGIA negotiations timeline
12	Consistency of suspension definition between serial and cluster
13	Clarity regarding timing of transmission cost reimbursement
14	Distribution of forfeited funds
15	Material modification requests (formerly “Inverter/transformer changes”)

Following release of the June 3 issue paper the ISO held a stakeholder web conference on June 11 and stakeholders provided written comments on June 25.

As explained in both the April 8 scoping proposal and the June 3 issue paper, the ISO anticipated from the beginning of the IPE initiative that the pace of development of proposals for each topic

[9] The remaining topics, which the ISO did not initially recommend be in scope, are described in section 4 of the April 8 scoping proposal.

may differ—i.e., proposals for some topics may be developed rather quickly whereas more time may be needed to work with stakeholders and develop proposals for other topics. For example, the ISO expected that the pace of work on the queue management topics (i.e., topics 6-12) would be such to enable the proposals for these topics to go to the ISO Board for approval earlier than the non-queue management topics in this initiative. Consistent with this approach, while the June 3 issue paper was a conventional issue paper for some of the fifteen topics in scope, it served as a straw proposal on others. Specifically, for the seven topics addressing queue management issues (*i.e.*, topics 6-12[10]), the ISO offered straw proposals in the June 3 paper. For the remaining eight topics (*i.e.*, topics 1-5[11] and 13-15[12]), the ISO was not prepared to offer a proposal in the June 3 issue paper and instead provided further analysis of the issues and suggested potential ideas and options for stakeholder consideration.

Following publication of the June 3 issue paper and receipt of stakeholder comments, the ISO posted a draft final proposal for topics 6-12 on July 2. This was followed with a stakeholder web conference on July 10 and written stakeholder comments on July 16. The ISO took the proposals for topics 6-11 to the September meeting of the ISO Board, received Board approval, and has filed the associated tariff amendments with the Federal Energy Regulatory Commission (FERC) on September 30, 2013 in Docket No. ER13-2482. As a result, topics 6-11 are not addressed in this straw proposal paper; however, topic 12 has been carried over and included in the present paper.

On July 18, the ISO published a straw proposal paper addressing topics 1-5 and 13-15. The July 18 paper offered straw proposals for topics 1, 2, and 3. The July 18 paper also presented a straw proposal for topic 15 (called "inverter/transformer changes" at the time, but now called "material modification review"); however, implementation of this proposal will be through the business practice manual change process rather than through tariff changes.[13] In the July 18 paper the ISO was not prepared to offer straw proposals on topics 4, 5, 13, and 14; nevertheless, the discussion of these four topics provided additional analysis and, for some, offered options for stakeholder consideration (*e.g.,* topics 13 and 14). The ISO presented the July 18 paper during a stakeholder web conference on August 8 and received written comments from stakeholders on August 22.

[10] These seven topics are: (6) provide for ability to charge customer for costs for processing a material modification request; (7) COD modification provision for SGIP projects; (8) length of time in queue provision for SGIP projects; (9) clarify that PTO not ISO tenders GIA; (10) timeline for tendering draft GIAs; (11) LGIA negotiations timeline; and, (12) consistency of suspension definition between serial and cluster.

[11] These five topics are: (1) future downsizing policy; (2) disconnection of completed phase(s) of project due to failure to complete subsequent phase; (3) clarify tariff and GIA provisions related to dividing up GIAs into multiple phases; (4) improve the Independent Study Process; and, (5) improve the Fast Track Process.

[12] These three topics are: (13) clarification of timing of transmission cost reimbursement; (14) distribution of forfeited funds; and, (15) material modification review.

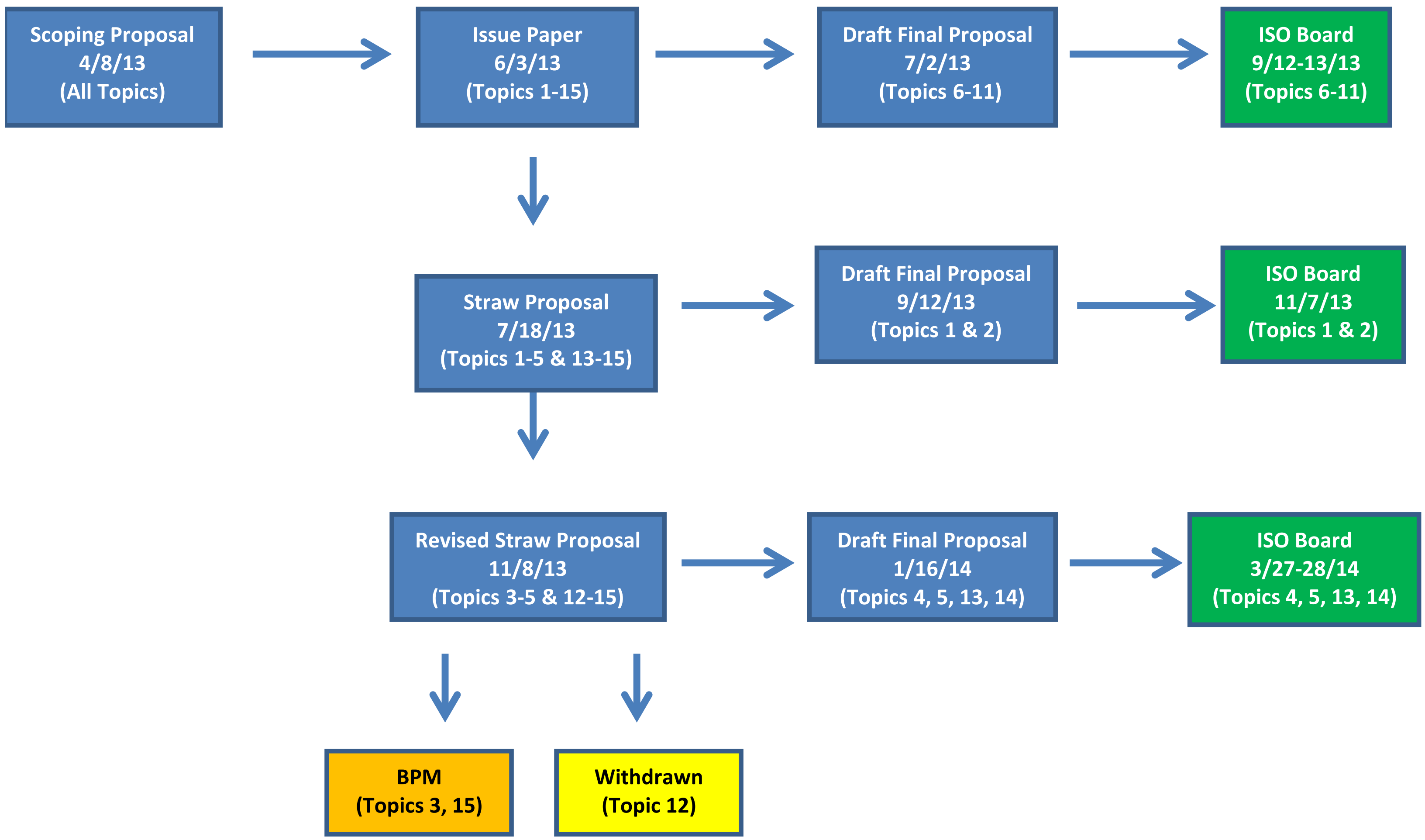
[13] In an effort to consult with stakeholders prior to initiating the BPM change management process in January 2014, the ISO began a series of stakeholder web conferences on Topic 15 with the first such web conference held on October 29.

On September 12, the ISO published a draft final proposal for topics 1 and 2. After receiving stakeholder feedback, the ISO made further refinements and modifications to the draft final proposal which it published in a series of addendums – the first on September 24 and the second on October 21. The ISO will present its proposals for topics 1 and 2 to the ISO Board for approval at its November 7 meeting.

Thus, the subject of this paper is the remaining seven topics of the IPE initiative. Initial or revised straw proposals are offered on topics 3-5, 13 and 14. Although a straw proposal was already offered for topic 15 in the July 18 paper, the ISO is nonetheless including the topic once again in the present paper to maintain clarity and still intends to take this topic through the BPM change management process as discussed during the stakeholder call on October 29. In the present paper, the ISO is also proposing to implement its proposal for topic 3 through the BPM change management process. With respect to topic 12, the ISO is withdrawing the topic as discussed further below. Proposals for those topics requiring tariff amendments (*i.e.,* topics 4, 5, 13, and 14) will be presented to the ISO Board for approval at its March 2014 meeting.

As was stated early in the IPE initiative, the most efficient course has been to take the topics before the ISO Board as they are ready and not hold up their resolution until all 15 topics are resolved (*i.e.*, take the draft final proposals on the various topics to the Board in several tranches). The ISO believes that stakeholders both support and appreciate this multiple-tranche approach since it accelerates resolution of the topics that can be resolved more quickly and gives due consideration to the topics that require more deliberation. Figure 1 on the following page is intended to provide an overview of the progression of all 15 topics within the scope of this initiative by illustrating which topics are addressed in which papers, and which Board meeting is targeted for the specific topics.

Figure 1 – Progression of proposal development for the 15 topics in the IPE initiative



3 Stakeholder process next steps

Table 2 summarizes the anticipated stakeholder process schedule for these remaining seven topics of the IPE initiative addressed in this paper.

Table 2 – Stakeholder process schedule

Step	Date	Milestone
Revised straw proposal (Topics 3-5 & 12-15)	November 8	Post straw proposal
	November 18	Stakeholder meeting (web conference)
	December 6	Stakeholder comments due
Draft final proposal (Topics 4, 5, 13, 14)	January 16	Post draft final proposal
	January 28	Stakeholder meeting (web conference)
	February 11	Stakeholder comments due
Board approval	March 27-28	ISO Board meeting (Topics 4, 5, 13, 14)

4 Topics

This section discusses the issues associated with Topics 3-5 and 12-15, summarizes stakeholder comments received in response to discussion of these topics in the July 18 straw proposal paper, and for some of the topics, offers an initial or revised straw proposal to address the issues identified. The ISO invites stakeholders to provide feedback on the issues identified as well as on the options or straw proposals offered, as applicable.

4.1 Topic 3 – Clarify tariff and GIA provisions related to dividing up GIAs into multiple phases or generating projects

4.1.1 *Overview*

This topic addresses the situation where an interconnection customer has submitted an interconnection request for a project, and then at a later time wishes to develop the project in a number of phases, as a Phased Generating Facility, with each phase having the same or a different commercial operation date ("COD") such that the MW capacities of the phases add up to the total MW capacity of the entire project as specified in the interconnection request.[14]

This topic is supported by many generation project developers who believe that they need greater flexibility to develop projects in smaller pieces (or "phases") in order to better meet load serving entity power purchase agreement procurement opportunities. The ISO currently permits an interconnection customer to develop its project in phases, which are negotiated and then reflected in the appendices to the interconnection agreement.

The scope of this topic includes all interconnection customers, including those that enter the interconnection queue under the GIDAP.

Provided below is a list of what the ISO allows under its current business practice as to phasing.

1. An interconnection request must be submitted for each proposed generation project.
2. Each interconnection request can result in not more than one interconnection agreement; however multiple interconnection requests at the same point of interconnection can be incorporated into one interconnection agreement.
3. An interconnection customer is allowed to develop its project in phases. A Phased Generating Facility is defined as a Generating Facility that is structured to be completed and to achieve Commercial Operation in two or more successive phases that are specified in a GIA, such that each phase comprises a portion of the total megawatt generation capacity of the entire Generating Facility. Consistent with every project, a Phased Generating Facility achieving commercial operation is subject to the reliability upgrades and interconnection facilities required for each phase being in service. Requests for phasing, whether the request involves moving the CODs of the phases so that they occur before the COD specified in the interconnection request for the overall project, or after the COD specified in the interconnection request for the overall project, require a material modification review to ensure that other projects are not negatively impacted by phasing of the project that has requested phasing. Similar to a modification request for COD extension, a request for phasing will not typically require a study. If the material modification request is approved and the project is then phased, the last phase must achieve commercial operation by the approved COD specified for the entire project. If the final phase of the project is not going to achieve the approved COD, then the interconnection customer must submit a request for material modification review to request a new COD.

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[14] This topic is distinct from phased implementation of a project. Regardless of whether a customer is proposing distinct phases or has distinct phases in its interconnection agreement, customers request to bring their project on line in phases and the ISO will work with the customer and the transmission owner to allow phased implementation if other requirements have been met, including reliability network upgrades.

4. If a project requests phasing during the study process, the ISO assumes a single COD and a single MW capacity based on the latest COD requested and total MW for the project. The first time the ISO will incorporate the phasing request is in the negotiation of the GIA.
5. To date, the ISO has allowed a maximum of four phases per project.
6. Where an interconnection customer has developed its project in phases, the ISO has allowed the phases to have different owners, so long as all of the owners are affiliates of the interconnection customer, but only under the condition that all of the co-owners must agree to assume joint and several liability for all of the obligations relating to the interconnection and are signatories to the interconnection agreement. This means that all of the owners are both individually and collectively responsible for all of the interconnection obligations.

4.1.2 *Stakeholder comments*

The written stakeholder comments that were received on this topic in response to the July 18 straw proposal are summarized in the table below. The table also includes ISO responses.

Table 3 – August 22 stakeholder comments on July 18 straw proposal

Issue	Stakeholder Comment	ISO Response
Timing of Phasing Request	**CalWEA** - Should be no limit on timing of phasing (or re-phasing) request. Even after it has reached COD and entered into operation (say, as a merchant plant), a project, and its GIA, should be allowed to be split (phased) to reflect PPA opportunities that project faces. Principle could apply to projects whose PPAs have expired and may need to re-split (re-phase) their GIA to reflect new merchant and PPA opportunities.	The ISO agrees with the comment with respect to limitations on phasing and has included this feature in the design of the phasing proposal. The proposal provides that an interconnection customer will be allowed to submit a request for phasing at any time during the life cycle of development of the generation project, up until the last phase of the generation project has reached commercial operation and all interconnection and transmission facilities have been completed. The ISO is willing to consider allowing phasing after the facility achieves COD; however we need to understand the reasoning for this type of an amendment to the GIA. However, to the extent that this comment is advocating for multiple GIAs relating to a single interconnection request, as noted above, and for reasons explained throughout this initiative, the ISO does not agree that it is appropriate to allow customers to split single interconnection requests into multiple GIAs.
Phasing must be Specified in GIA	**SCE** - Once phasing is defined, it should be incorporated into the interconnection agreement.	The ISO agrees with the comment and has included this feature in the design of the phasing proposal. The proposal provides that any phasing structure must be agreed to by the ISO and applicable PTO as part of the generator interconnection agreement negotiation. After a

Table 3 – August 22 stakeholder comments on July 18 straw proposal		
Issue	**Stakeholder Comment**	**ISO Response**
		phased structure for a project is agreed upon, it will be incorporated into the interconnection customer's interconnection agreement.
Relationship of Approved COD to request for Phasing	**SCE** - An IC's request to develop its project in a phased structure does not, standing alone, automatically extend the project's COD. **LSA and Silverado -** ISO should remove condition that last phase reach COD by latest approved COD for project, since that is likely to be physically impossible. More often than not, COD for project is dependent on completion of Interconnection Facilities and RNUs for project, and COD cannot usually be accelerated. Thus, if project is then phased, it is not possible for last project phase to come on-line by that date unless all phases have the same COD, which would negate a key benefit of phasing a project.	Response to SCE, LSA and Silverado's comments - The ISO agrees with the comments and has included these features in the design of the phasing proposal. See the proposal in sections 4.3.3 and 4.3.4 of this paper.
Use of Material Modification Review Process	**Six Cities** - Support processing a phasing request through material modification process. **CPUC -** Interconnection customer seeking to phase (and potentially change CODs for) an interconnection request must contact ISO and request phasing before Phase 2 studies have begun to avoid having to do this via a material modification request. **LSA and Silverado -** ISO should clarify in tariff that project phasing can be added as one of changes allowed after Phase I Study without submission of a material modification request. **CalWEA** - Does not see any reason for performing a material impact review for project that is proposing to phase its GIA given that, per ISO's solution under Topic 2, project remains obligated to finance all network upgrades that have been assigned to entire project to extent that later queued projects require those upgrades. **SCE** - Changes to phasing already defined in GIA will need to be evaluated for material impact and negotiated with ISO and PTO and GIA must be amended at IC's expense.	Response to Six Cities' comment - The ISO agrees with this comment and has included this feature in the design of the phasing proposal. See sections 4.3.3 and 4.3.4 of this proposal for specifics. Response to CPUC's comment - The design of the phasing proposal includes that the customer can avoid going to a material modification request if it requests phasing before the deadline for receiving information for the Phase 2 studies has been reached and the Phase 2 studies have been started. The proposal also provides ways for interconnection customers to request phasing at other points in time and does not limit the opportunity to only requesting phasing prior to the start of the Phase .2 studies. Some stakeholders have requested this flexibility. Response to LSA and Silverado's comments – The design of the phasing proposal clarifies the point made by LSA and Silverado. Response to CalWEA's comment – The ISO disagrees with the suggestion and believes that it is important to do a material impact review under certain circumstances. See proposal for those circumstances. Response to SCE's comment - The ISO agrees with this comment and has included this feature in the design of the phasing proposal. The cost recovery from the interconnection customer is already included in the changes made to the material modification assessment in topic 6.
Number and Size of Phases Allowed per Project	**CPUC -** Agree with basic proposal if consideration is given to desirability of placing reasonable (not severe) limits on number and sizes of phases allowed per project. **SDG&E** - Does not object to dividing a project into	Response to CPUC's comment - The ISO agrees with this comment and has included this feature in the design of the phasing proposal. The ISO views its suggested limits as reasonable and not severe limits on the number and sizes of phases

Table 3 – August 22 stakeholder comments on July 18 straw proposal		
Issue	**Stakeholder Comment**	**ISO Response**
	multiple phases; recommends there be a 5 MW minimum MW size for two or more phases. **SCE** - Should be some reasonable limits to reflect realities of number and magnitude of power procurement contracts being executed, as well as timelines for construction of network upgrades. Urges ISO to consider limits associated with number of phases allowed per project and request to create a specific phase amount should be accompanied by some form of reasonable and verifiable justification. Without establishing limits and requiring some form of justification, potential exists that voluminous amounts of changes to project phases will occur and stymie progress towards project completion, increase requests for project downsizing, or ultimately lead to project withdrawing to detriment of all. Definition of operational needs to satisfy all projects will be impossible to quantify if project phases are allowed to change with no limits imposed. **PG&E** - Stakeholders have not demonstrated a commercial need for unlimited flexibility in phasing. PG&E believes policy adopted must balance between creating commercially reasonable degree of flexibility and providing so much flexibility as to create an overly burdensome process for PTOs that would divert resources away from maximizing number of generators that can be interconnected in a timely manner. Propose the following: (a) ≤20 MW projects may have up to two phases, with no individual phase smaller than 1 MW (this is a modification from PG&E's suggestion in comments on the scoping proposal, which would have limited the smallest phase to 5 MW); and (b) >20 MW projects may have additional phases, provided no additional phase is smaller than the larger of 20 MW or 10% of the project nameplate capacity. **LSA -** Recognizes PG&E's concerns with potential large numbers of phases and has no objection to 20-50MW or smaller minimum phase sizes given commercial considerations such as RFO participation limits. **IEP** - Supports not limiting number of phases into which an interconnection request may be split, considers extreme scenario where 100 MW project splits into 100 phases of 1 MW is highly improbable, and commercial considerations will effectively self-limit number of phases to reasonable number.	allowed per project. Response to SDG&E's comment - The ISO agrees with this comment and has included this feature in the design of the phasing proposal. The ISO suggests a 5 MW minimum size for two or more phases, which is what is suggested by SDG&E. Response to SCE's comment - The ISO agrees with the comment about limiting the number of phases and establishing a specific phase amount and has included this feature in the design of the phasing proposal. However, the ISO does not agree that a request to create a specific phase amount should be accompanied by some form of justification as this will introduce too much subjectivity into the evaluation of the request, which may create equity and consistency issues. In addition, criteria would need to be developed that would be fair and equitable, which would be challenging. For example, although phasing associated with having a PPA for one phase but not the whole project may be straightforward to review, why would it not be okay to phase a project into smaller pieces to bid into auctions or position the project to be able to respond in the future to potential future requests for offers? The ISO proposes to make the phasing rules as black and white as possible. Response to PG&E's comment - The ISO agrees with the comments and has included this feature in the design of the phasing proposal. The ISO has included a proposal in this paper for discussion that has some limits, however, they are different than what PG&E has proposed. The ISO proposal for discussion does not go down as low as 1 MW as PG&E suggests (it goes down to 5 MW as the minimum size of a phase). The ISO is interested in receiving stakeholder feedback on what an appropriate minimum size might be and the commercial reasons for such size. It is not obvious that there is a commercial need for 1 MW as the minimum size. Response to LSA's comment - The ISO agrees with this comment and has included this feature in the design of the phasing proposal. The proposal does allow for 20-50MW or smaller minimum phase sizes. Response to IEP's comment - The ISO believes that it is appropriate to include some limit on the maximum number of phases, and the vast majority of stakeholder comments support this view. The proposal provides for a maximum of five phases, which is an increase from the current

Table 3 – August 22 stakeholder comments on July 18 straw proposal		
Issue	**Stakeholder Comment**	**ISO Response**
		practice of four phases as the maximum. The ISO does not believe that the number of phases allowed or the minimum MW size of a phase should be undefined and left wide-open. Vague rules, or a lack of rules, could lead to misunderstandings and/or disputes.
Timing of when Phases can come On-Line	**PG&E -** Propose that no more than one phase can be interconnected every month, with PTO discretion to further limit frequency of phases coming online in areas where doing so would create significant impacts to other generators. **CalWEA** - Required COD time delay for different phases of project should not be applied to projects that split (phase) post-COD.	Response to PG&E: The ISO agrees with PG&E and has included this feature in the design of the phasing proposal. From a logistic standpoint, the ISO and PTOs can only support one phase per month to achieve commercial operation due to documentation, approvals and coordination needed between the parties. The ISO will coordinate with the PTOs on the timing of the phases to ensure reliability of the grid. Response to CalWEA: The ISO disagrees with the suggestion and believes that it is important to have a coordinated implementation of commercial operation and with the volume of projects today and in the foreseeable future, only one phase per month can be supported from an operations perspective.
One Interconnection Agreement per Interconnection Request, Joint and Several Liability, and Relationship of Multiple Owners	**SDG&E** - Believe there should be only one interconnection agreement for each interconnection request. IC should be free to involve multiple entities in project through whatever commercial arrangements it chooses provided all project participants agree to be bound by provisions of single interconnection agreement. **Six Cities** - Support ISO's proposal to retain requirement for owners of phased, multi-owner project to assume joint and several liability for all of obligations relating to interconnection as specified in GIA. **IEP -** During August 8 stakeholder meeting, participants discussed concept of splitting a project into phases with non-affiliated but contractually bound parties owning separate phases under same GIA, provided they agree to joint and several liability. Generally support concepts that provide for additional commercial flexibility and would support tariff provisions that allow project to be split into phases that are "owned" by parties that are affiliated, non-affiliated, or both. Would entail all parties, affiliated or not, agreeing to joint and several liability which would provide ISO with contractual protection it desires while offering a valuable option for generators. **LSA and Silverado -** Should reconsider allowing splitting of a project into multiple GIAs, and without joint and several liability provisions as long as all obligations to ISO and PTO are covered. Approach could be simpler than current multiple-LLC	Response to SDG&E, Six Cities, IEP, LSA and Silverado comments - Consistent with FERC's pro forma interconnection procedures, the ISO's interconnection process is designed and structured based on the submission of individual generating facility projects through separate interconnection requests, culminating in a single interconnection agreement for each project. We have also allowed two interconnection requests that became one project at the same point of interconnection that has the same owner to combine the two projects under one GIA. Over the past few years, the ISO has provided increasing flexibility to allow customers to develop their generation projects in discrete phases—up to four—and to allow more than one owner to sign a non-conforming interconnection agreement. Early versions involved affiliates that were tenants-in-common with respect to all of the project assets. While the ISO is prepared to provide some additional flexibility, as discussed below, the ISO is not willing to compromise on two fundamental requirements: (1) joint and several liability among all owners with respect to all obligations under the GIA and all assets; and (2) one interconnection agreement per project/interconnection request. The ISO agrees that the joint ownership option should not be limited to affiliates and that separate ownership of separate phases can be accommodated. The ISO is also willing to

Table 3 – August 22 stakeholder comments on July 18 straw proposal

Issue	Stakeholder Comment	ISO Response
	structure and address problems associated with cancellation of later project phases since an entire LGIA for project/phase could be canceled. ISO has not adequately explained its objections, and should do so to allow stakeholders to consider those objections and address them. There is no obvious reason why splitting a 100 MW project into two separate 50-MW projects with their own separate LGIAs and attendant obligations would leave ISO at greater risk than if those projects had submitted separate interconnection requests at beginning, as long as all financial-security and payment obligations under original agreement are apportioned between new projects. Ask ISO to recognize that ISO is responsible, in part, for high level of developer interest in this potential option. ISO has indicated that restrictions may be placed on number of separate ISO meters and/or resource IDs for phased projects. Splitting projects into phases can make projects more viable by allowing separate PPAs and buyers for each phase, but those benefits would be substantially impaired if phases cannot be scheduled and settled separately. If ISO does not allow splitting a project into multiple GIAs, it should clarify that each project phase can be separately metered and scheduled/settled under its own unique resource ID.	consider additional flexibility concerning the number and size of phases. However, the concept of splitting a single generating facility project into multiple interconnection agreements is not consistent with the interconnection process and provides additional risk to the ISO that it is not willing to accept. First, because each individual project is studied as a single generating facility and the obligations under the interconnection agreement relate to all phases of that generating facility, the ISO requires that the entities who own separate phases of a single project agree to be jointly and severally liability for all obligations with respect to the generating facility and the interconnection facilities under the interconnection agreement. This requirement is critical to the ISO's ability to manage the risks associated with allowing separate ownership of the phases of a single generating project, such as the obligations of the phase owners with respect to shared interconnection facilities. Allowing separate interconnection agreements would eviscerate this protection. *If an interconnection customer desires separate interconnection agreements, the interconnection customer should submit separate interconnection requests.* In addition, permitting interconnection customers to use phasing to split individual generating projects into multiple projects with separate interconnection agreements and no legal relationship would create a perverse incentive for developers to submit unrealistic and oversized projects, because there would be no impediment to breaking these "projects" up into smaller discrete facilities and disposing of them freely. Allowing separate interconnection agreements would encourage the submission of unrealistically scoped projects, undermining the efficiency of the interconnection process while raising concerns regarding fairness for customers who submit interconnection requests for realistic projects, as clearly contemplated by the ISO's interconnection procedures.
Phased Projects Must Make Progress	**SCE** - Irrespective of thresholds in terms of limit on number of phases allowed or limit on MW size of each phase, each phase must make progress so that all the phases evaluated collectively will result in project complying with provisions of a single interconnection request.	The ISO agrees with the comment. The interconnection agreement for each phased project will include development milestones for each phase to ensure that the overall project makes progress so that all of the phases evaluated collectively will result in the project complying with the provisions of the single interconnection request. The proposal provides

Table 3 – August 22 stakeholder comments on July 18 straw proposal		
Issue	**Stakeholder Comment**	**ISO Response**
		that any phasing structure must be agreed to by the ISO and applicable PTO as part of the generator interconnection agreement negotiation. After a phased structure for a project is agreed upon, it will be incorporated into the interconnection customer's interconnection agreement and milestones will be included in the interconnection agreement to provide a mechanism to track and enforce obligations for each phase.
Deposit Reimbursements for Phased Projects	**CPUC -** Agree with basic proposal if deposit reimbursements for phased versus non-phased projects are further considered as discussed under Topic 13.	Deposit reimbursements for phased versus non-phased projects are being further considered in this paper as discussed under Topic 13.
Allow Projects to Combine	**LSA and Silverado -** ISO should allow projects to combine (e.g., to facilitate construction of stand-alone network upgrades), if all obligations to ISO and PTO are covered – an options discussed earlier in this initiative but dropped in straw proposal.	The ISO already allows projects to combine. This was explained in the ISO's written response to the previous round of stakeholder comments on this topic. On August 7, 2013, the ISO responded as re-iterated below to this same comment from LSA. "The ISO does allow projects to combine. The ISO has allowed up to a maximum of three interconnection requests to be combined into one interconnection agreement, but only under the conditions that the interconnection requests must be at the same point of interconnection, be the same location/site/facility and have the same interconnection customer (legal name; LLC as an example)." Moreover, the topic was not "dropped" because it is already being implemented.

4.1.3 *Changes to July 18 straw proposal to create revised straw proposal*

The changes to the July 18 straw proposal that were made to create the revised straw proposal for this topic are summarized below.

1. Limits on minimum MW size of phase and maximum number of phases allowed – One of the main themes of stakeholder comments is for the ISO to consider providing some limits on both the minimum MW size of a phase as well as the maximum number of phases that would be allowed for a project.

   PG&E, SCE, SDG&E and the CPUC state support in their written comments for establishing some reasonable limits on both the number and sizes of phases allowed per project. LSA stated in its written comments that it recognizes PG&E's concerns with potential large numbers of phases and does not object to 20-50 MW or smaller minimum phase sizes given commercial considerations. Only one stakeholder in its written comments, IEP, supports not limiting the number of phases allowed, as it believes that commercial considerations will effectively self-limit the number of phases to a reasonable number. In summary, many stakeholders believe that it is desirable to have some limits on phasing, and stakeholders have not voiced a commercial need for unlimited flexibility in phasing.

As a result of these comments, the ISO supports establishing some reasonable limits on both the number and sizes of phases allowed per project. The question now becomes, "What is a reasonable limit?"

To facilitate discussion, the ISO offers in this paper a revised straw proposal for a minimum MW amount of 5 MW and a maximum number of phases allowed of 5 phases. The ISO considered the following factors in developing its revised straw proposal for this topic.

- The ISO believes that it should strive to make the phasing rules as simple as it can, it is appropriate to provide a phasing option to both small and large projects, and there should be a meaningful way for both small and large projects to benefit from phasing.
- To date the ISO has allowed up to four phases per project and this appears to be working reasonably well. The ISO is willing to consider increasing the maximum number of phases allowed to be as large as five phases.
- Allowing phasing has work load and work scheduling impacts on both the ISO and PTO.
- Allowing phasing seems reasonable, but how small of a phase makes sense? For example, would allowing phasing down to a 1 MW amount be appropriate? In its comments PG&E has suggested providing the option for <u>one</u> phase being as small as 1 MW to provide the generator the ability to get a small block of generation online for commercial or technical reasons. PG&E believes that allowing all phases of a project to be potentially as small as 1 MW is excessive, but allowing one phase to be this small may be appropriate.
- Allowing a minimum MW size of a phase as small as 5 MW may have value, such as for the renewable auction mechanism program at the CPUC.

The ISO asks stakeholders to provide feedback on the commercial reasons they need phasing, what the minimum MW amount and maximum number of phases allowed might be, and whether limits such as those proposed in this paper can meet the needs of stakeholders. For example, if you believe that more liberal limits are needed than that proposed by the ISO in this revised straw proposal, please provide the proposed limits and the commercial/business justification.

SCE has commented that phasing can create challenges in planning the development of facilities on its system when the timing of facilities changes due to changes in the timing of phases. SCE would like to be able to depend on a list of facilities and schedule for developing a project, and a binding commitment from the project developer is needed. Such a commitment could be provided through an executed interconnection agreement with detailed phases including facilities and milestones for each phase.

2. Clarify that a request for phasing is not the mechanism for approving an extension of COD – In this paper the ISO is clarifying that if an interconnection customer desires to extend the COD of its project beyond the currently approved COD as part of its request for phased development, such request for a COD extension will need to be evaluated by the ISO in its material modification review process if the customer submits its phasing request after the commencement of the Phase II study, *i.e.*, a request for phasing will not be treated, by itself, as a request for a change in COD. Likewise, approval of phasing will not constitute, by itself, approval of a change in the COD. The impact of each of these proposed modifications must be reviewed by the ISO, even if they are submitted together.

   Stakeholders asked for clarification of this issue during the August 8, 2013 stakeholder meeting and in their written comments. The ISO is clarifying the language of the proposal to distinguish clearly between the types of changes that can be made through phasing and the mechanism the ISO uses to process that request.

3. When a request for phasing can be submitted – In this paper the ISO is clarifying when a request for phasing can be made and associated timing considerations.

   The ISO is adding additional detail on this aspect of the proposal in response to comments received from stakeholders during the August 8 stakeholder meeting and in their written comments received August 22. Stakeholders feel that the previous description of this aspect of the proposal needs to be augmented to better describe the various points in time during the interconnection process when requests for phasing can be made and how the timing of the request for phasing may affect when an answer would be given to the interconnection customer regarding whether the request is approved.

4. Requirements when there is more than one owner of a project – In this paper the ISO has made a change in the proposal such that, where the interconnection customer contemplates more than one owner of the project, such as a different owner of each phase, the ISO will not require that all of the owners be affiliates of the interconnection customer.

   During the August 8 stakeholder meeting and in their August 22 written comments stakeholders asked the ISO to reconsider its current business practice that if there are phases and different owners among the phases, then the owners must be affiliates of the interconnection customer. The ISO has considered these comments and decided that in the interest of providing additional flexibility to interconnection customers it will no longer require that the different owners be affiliates of the interconnection customer. This change will allow additional opportunities for project developers and expand the potential pool of sponsors for a project.

However, the ISO will continue to require that all of the entities that own phases of the same proposed generating facility agree to assume joint and several liability for all of the obligations relating to the interconnection request. This means that all of the owners are both individually and collectively responsible for all of the interconnection obligations. The joint and several liability requirement, enforced through a single interconnection agreement which all owners must sign, is a key provision that provides the protection the ISO requires with regard to phased development and different owners of phases. Interconnection customers have the option to submit separate interconnection requests if they want to avoid joint and several liability or if they desire to have separate generator interconnection agreements for each owner.

5. <u>Changes to phasing will be in the business practice manual and not in the tariff</u> – Because the ISO tariff already allows for a Phased Generating Facility, additional tariff language is not needed. The ISO clarifies in this paper that it intends to address phasing principles in the business practice manual and not in the tariff.

4.1.4 *Revised Straw Proposal*

The ISO's revised straw proposal for this topic is provided below.

1. An interconnection project can be developed in phases, as a Phased Generating Facility, such that each phase may be planned to reach commercial operation upon the same or different date, subject to the reliability upgrades and interconnection facilities required for each phase being in service.
2. The option to develop an interconnection project in phases will be available to interconnection customers in all interconnection queues, including interconnection customers that submit interconnection requests under the GIDAP.
3. An interconnection customer is allowed to submit a request for phasing at almost any time during the life cycle of the generation project up to the final commercial operation date of the project.[15] Additional information on the timing of requests for phasing and how the interconnection customer requests phasing is provided below.
    a. <u>Interconnection Request</u>: An interconnection customer can request phasing when it submits its interconnection request. Attachment 1 to the GIP/GIDAP is the interconnection request form. The form requires information on project size, commercial operation date, deliverability status, and other interconnection

[15] As discussed in the stakeholder matrix, the ISO is willing to consider allowing phasing after a project has reached its commercial operation date, but the ISO wishes to understand from developers the need for such a provision.

information. The interconnection customer requesting phasing would reflect the phasing dates in the schedule section of the form (*e.g.,* Begin Construction Date: Phase A – January 1, 2014; Phase B – July 1, 2016). However, if a project requests phasing during the study process, the ISO would still assume a single COD and a single MW capacity based on the latest COD requested and total MW for the project in the study process. The first time the ISO will incorporate the phasing request is in the negotiation of the GIA.

b. Between Phase I and Phase II Studies: If the interconnection wants to request phasing during this period, the interconnection customer should include the phasing request when submitting GIP/GIDAP Appendix 2, Appendix B. Appendix B is an appendix to the interconnection request (a form) that the interconnection customer must submit after the phase I study to update the interconnection request for the Phase II study. The form requires information on project size, commercial operation date, deliverability status, and other interconnection information. The interconnection customer requesting phasing would reflect the phasing dates in the schedule section of the form (*e.g.,* Begin Construction Date: Phase A – January 1, 2014; Phase B – July 1, 2016). [DAL – no. See the sentence I put back into a.

c. After Phase II Study Results are published: Any phasing request made after the Phase II study results are published will require a material modification review to determine if the requested change would impact other projects. The interconnection customer requesting phasing would submit a request to QueueManagement@caiso.com. If the phasing request is determined to be a material modification, then the customer will not be permitted to implement its phasing proposal without submitting a new interconnection request.

d. If the interconnection customer requests phasing while either the Phase I or Phase II study is ongoing, the ISO will hold the request until after that phase's study results have been published and then process the request in accordance with either category b. or c. above, as applicable. The reason for this is that the ISO and PTOs cannot incorporate new data for a project and the data for a study cannot change once the study has commenced.

4. If an interconnection customer wishes to have a COD for one or more phases that is different than the customers' currently approved COD(s), then the interconnection customer would request that change at the same time as the phasing change through the same process as the phasing change discussed above. As an example, consider an interconnection request for a 400 MW generating facility with a requested COD of July 1, 2016:

   a. If, after Phase I study results have been published, the project wants to split into two phases of 200 MW with a COD for Phase A of July 1, 2015 and COD for Phase B of

July 1, 2016, then the interconnection customer would, between the Phase I and Phase II studies, submit an Appendix B form that states "Generating Facility size (MW): Phase A - 200 MW, Phase B – 200 MW" and "Commercial Operation Date: Phase A –July 1, 2015, Phase B – July 1, 2016".

b. If, instead, the project requests a split into two phases of 200 MW after the Phase II study results have been published, , then the interconnection customer would send a request to QueueManagement@caiso.com for phasing. If the interconnection customer wishes to have a COD for one or more of these phases that is different from the July 1, 2016 COD reflected in its interconnection request, then the customer would need to indicate those dates in its phasing request, and the ISO will evaluate the proposed COD changes along with the phasing proposal in its modification review. If the project does not yet know if it wants to change the COD of the phases, it may do so at a later date by submitting a request for modification.

5. In each instance, the requested phasing structure must be agreed to by the ISO and applicable PTO. If the interconnection agreement is already executed, then the parties will amend the agreement. If the interconnection agreement is not executed then the approved phasing will be addressed and included in the interconnection agreement as part of the generator interconnection agreement negotiation process. The interconnection customer's interconnection agreement will include discrete milestones for each phase of the project in the interconnection agreement to provide a mechanism to track and enforce obligations for each phase.
6. The minimum MW size of a phase of a project is 5 MW.
7. The maximum number of phases allowed for a project is five phases.
8. Because phasing may involve different dates for the commercial operation of the phases, the ISO will require that no more than one phase can reach commercial operation each month. The ISO will coordinate with the PTOs on the timing of the phases to ensure reliability of the grid. The ISO has found that there is a great deal of setup and integration work required for the start of commercial operation on the ISO grid, so it is not practical to integrate more than one phase of a project per month and still meet all the integration requirements to ensure reliable operation of the grid and efficient operation of the markets.
9. Once a project is phased and the phasing is incorporated into the customer's interconnection agreement, any request to modify the phasing plan will require a material modification review.
10. The ISO will allow an interconnection customer to develop its project in phases under a single interconnection agreement and allow the phases to have different owners. All of the

owners of the phases of a single project must agree to assume joint and several liability for all of the obligations relating to the interconnection request and specified in the interconnection agreement, *i.e.*, all of the owners are both individually and collectively responsible for all of the interconnection obligations specified in the interconnection agreement. The ISO proposes the following change to the current business practice: The ISO will not require that all of the owners be affiliates of the interconnection customer.

11. If a project is a Phased Generating Facility, then that does not necessarily mean that each phase is a discrete generating unit that can be scheduled and bid into the ISO's markets. The interconnection customer would need to meet the metering standards for each phase if that is the customer's objective.

4.2 Topic 4 – Improve Independent Study Process

The purpose of the Independent Study Process (ISP) enhancement effort is to revisit the tests for independence and to align the process timeline with the overall ISP intent. To qualify under the ISP, the interconnection customer must provide, along with its interconnection request, an objective demonstration that inclusion in a queue cluster will not accommodate the desired commercial operation date for the generating facility. Per the existing process, an IR submitted in the ISP will have its electrical independence tested against the study results of projects in the most recently completed studies of the latest cluster as well as earlier ISP projects in the ISO queue. Under the existing ISP, if the determination of electrical independence by ISO and PTOs is not completed prior to the close of any given open cluster application window, the customer's ISP project will have to wait for the studies of the recently closed cluster application window to be far enough along to be able to determine its electrical independence against the projects in that latest cluster.

4.2.1 *ISP working group*

In the June 3 issue paper the ISO proposed an ISP working group to take on the tasks outlined above. The PTOs perform the studies for reliability network upgrades under the direction of the ISO, and they perform the independence test for projects seeking to enter the ISP. Consequently, the working group includes both engineers and participants with policy expertise from the PTOs and the ISO. This technical input is of vital importance to achieving a workable and technically sound resolution to the issues associated with the ISP. Additionally, participants from the generation development community with both technical and policy expertise were also encouraged to participate.

The ISP working group held bi-weekly meetings starting from July 29, 2013. The intent was to hold working group meetings on a bi-weekly basis until a final proposal is developed that has been vetted with the broader IPE stakeholder group. It is anticipated that the final ISP proposal will be completed in early 2014 and be taken to the ISO Board of Governors for approval at its March 2014 meeting. The ISP working group and the Fast Track working group typically held back-to-back working group meetings as most of the participants in one work group also participated in the other.

The ISP working group reviewed the existing process and identified the following key areas in need of an enhancement:

1. Criteria for ISP Eligibility
2. Process and Timeline Enhancements
3. Tests for Electrical Independence
4. Clarification on BTM (Behind-the-meter) Expansion and its Impact on the NQC

These four areas are addressed as part of the straw proposal in section 4.2.3.

4.2.2 *Stakeholder comments*

Stakeholder comments received August 22 following publication of the July 18 straw proposal are summarized below.

CPUC – It could be valuable to allow interconnection customers to utilize the independent study route if requesting energy-only status for initial interconnection and meeting all other criteria for independent study – and then at a later time to pursue full deliverability via whatever process and studies are necessary.

PG&E - Deliverability methodology reform should not be an objective of this track. Exempting ISP from deliverability methodology could create negative impacts for larger projects seeking deliverability. Offer deliverability as a separate add-on attribute that ISP projects could apply for via the standard cluster study process. Consider integrating the ISP into the FT process. The ISP would be similar to the FT, such as a hybrid FT process that includes the flexibility to accommodate ISP style characteristics. This could be done by allowing the hybrid FT process to allow projects to apply for deliverability separately through the normal cluster study process.

IEP - Allow energy-only status while waiting for deliverability.

CalWEA – Generally agrees with the CAISO's preliminary ideas in this area.

4.2.3 *Straw proposal*

The straw proposal on this topic is presented in four parts to address the following four key areas which are in need of an enhancement: (1) criteria for ISP eligibility; (2) process and timeline enhancements; (3) tests for electrical independence; and, (4) clarification on behind-the-meter (BTM) expansion and its impact on the NQC.

4.2.3.1 Criteria for ISP eligibility

Per the existing tariff, an Interconnection Customer that wishes to utilize the ISP must show that its desired Commercial Operation Date is physically and commercially achievable, by demonstrating at least two of the following:

1. The Interconnection Customer has obtained, or has demonstrated the ability to obtain, all regulatory approvals and permits needed to complete construction in time to meet the Generating Facility's requested Commercial Operation Date.
2. The Interconnection Customer is able to provide, or has demonstrated the ability to obtain, a purchase order for generating equipment specific to the proposed Generating Facility, or a statement signed by an officer or authorized agent of the Interconnection Customer demonstrating that the Interconnection Customer has a commitment for the supply of its major generating equipment in time to meet the Commercial Operation Date through a purchase agreement to which the Interconnection Customer is a party.
3. The Interconnection Customer can provide reasonable evidence of adequate financing or other financial resources necessary to make the Interconnection Financial Security postings.

The ISP working group recommends that all three conditions listed above be met (rather than only two) and two additional criteria be satisfied as part of the initial screening/validation. This proposed revision is intended to provide greater assurances that projects requesting this option truly have a need for this option versus the standard interconnection process, have the ability to perform under this option, and the project's requested COD is achievable based on the requested point of interconnection and any network upgrades expected to be needed for the customer's project.

4. The proposed point of interconnection must be an existing facility in the ISO Controlled Grid or a transmission upgrade approved in ISO transmission planning process (TPP) that has completed permitting and is currently under construction. The facility where the point of interconnection is proposed must be able to accommodate the interconnection of the ISP project. The most updated expected in-service date of this upgrade must be able to accommodate the proposed COD of the ISP project.
5. There is no network upgrade, already part of an existing GIP/GIDAP or TPP plan that is known to the ISO or PTO, that is needed to allow the project to reliably enter into commercial operation, that (i) is yet to be operational and (ii) has a completion date that is later than the ISP's requested COD or is not yet fully permitted and currently under construction.

4.2.3.2 Process and timeline enhancements

The following is a summary of enhancements proposed to the study process and timeline for projects which are deemed eligible for ISP based on the criteria described in the previous section.

1. Cluster/ISP Independence Test – The working group recommends that a project should be given an opportunity to go directly into a System Impact Study (SIS) if there are no other cluster projects or ISP projects under study in the study area, as defined in the current cluster study, where the ISP project is seeking interconnection. If there are no cluster projects that are yet to complete the Phase II study process or ISP projects that are yet to complete the SIS, in the same cluster study area as the proposed ISP project, then the ISP will pass this test and will move forward with a System Impact Study (SIS) and a Facilities Study without having to satisfy the electrical independence test, which will be performed pursuant to CAISO Tariff Appendix DD Sections 4.4 and 4.5. After the SIS and Facilities Study are completed, the project will be eligible to start GIA negotiations as an Energy Only (EO) project.
2. Tests for Electrical Independence – If the ISP project is in a study area which has projects that have yet to complete the Phase II study process, thus failing the Cluster/ISP Independence Test, then the Phase I results of the current cluster (the last cluster which opened up before the ISP request was received) and SIS results of any previous ISP project in the same study area will be used to assess the electrical independence of the ISP project. The nature of Tests for Electrical Independence is explained in section 4.2.3.3 of this proposal document. If the project passes all the tests for electrical independence, then an SIS and Facilities Study will be performed pursuant to CAISO Tariff Appendix DD Sections 4.4 and 4.5. After the SIS and Facilities studies are completed, the project will be eligible to start GIA negotiations as an EO project.
3. If the project has requested Full Capacity Deliverability Status (FCDS) or Partial Capacity Deliverability Status (PCDS), it will be studied for deliverability as part of the Phase I and Phase II studies for the next cluster.
4. If a project fails to satisfy any of the Tests for Electrical Independence, it will be given an option to be part of the next cluster study, or to withdraw.
5. A project requesting an ISP and seeking FCDS or PCDS will by default be an 'Option A' project.
6. A project consisting of asynchronous generators, requesting ISP shall provide 0.95 (lead/lag) power factor at the point of interconnection.

A simplified process flow diagram is as follows:

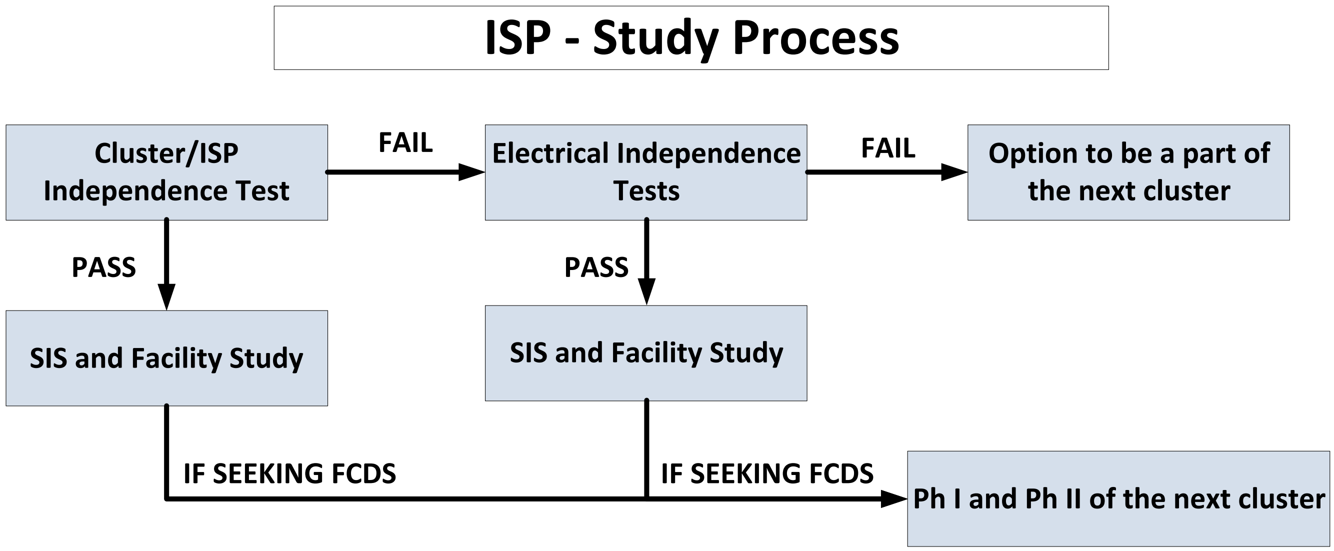

Figure 2 – Proposed Process Enhancement to ISP

The following timeline is proposed for completing the SIS and Facilities Study:

- 30 calendar days to perform IR validation and ISP eligibility screening
- 30 calendar days to perform Tests for Electrical Independence, once the necessary data becomes available (see below)
- 120 calendar days to complete the SIS and Facilities Study after the execution of an Independent Study Process Study Agreement. (CAISO tariff Appendix DD section 4.4.4)

For projects seeking FCDS or PCDS, the SIS and Facilities Study must be completed before the project's request for deliverability can be studied as part of the next cluster for deliverability assessment. If the SIS and Facilities Study cannot be completed in time, the project will be given an option to be part of the next cluster window.

With respect to a project requesting ISP in a study area with cluster projects in the current cluster the timeline for conducting the electrical independence test will commence only when: (i) Phase I results of the current cluster are available; and, (ii) there are no ISP projects in the same study area that have not had their SISs completed.

ISP projects will be required to forego the suspension rights currently included in the ISO's pro forma GIAs.

Consider the following examples to further illustrate the process timeline.

Example 1: Consider that an ISP request is received in May 2014 (after March 31, 2014). If it passes the Cluster/ISP Independence Test, then a SIS and Facilities study will be performed (using the latest cluster base case which is ready) and the project will be eligible to interconnect as an Energy

Only (EO) project after signing its EO GIA – as early as Q4/2014. If the project is seeking FCDS or PCDS, then it will be studied as an Option A project as part of the next cluster (Cluster 8) to receive its Phase II study as early as Q4/2016 and Transmission Plan Deliverability (TPD) allocation Q2/2017.

Compare this to the existing process – an ISP request received in May 2014 will be tested for independence after the Phase II results for the current cluster (Cluster 7) become available (Q4/2015). If the project passes the tests, then an SIS and Facilities Study will be performed after which the project can potentially interconnect as an EO project. If the project is seeking FCDS or PCDS, it will be studied as part of next cluster's (Cluster 8) Phase II study (Q4/2016) and receive its TPD allocation in Q2/2017.

Example 2: Consider that an ISP request is received in May 2014 (after March 31, 2014). If it fails the Cluster/ISP Independence Test, then the Tests for Electrical Independence will be performed using Phase I results of the current cluster (cluster 7) (Q1/2015). If the project passes the Tests for Electrical Independence, then a SIS and Facilities Study will be performed (using the latest cluster base case which is ready) and the project will be eligible to interconnect as an Energy Only (EO) project after signing its EO GIA – as early as Q1/2015. If the project is seeking FCDS or PCDS, then it will be studied as an Option A project as part of the next cluster (Cluster 8) to receive its Phase II study as early as Q4/2016 and TPD allocation in Q2/2017.

Compare this to the existing process – an ISP request received in May 2014 will be tested for independence after the Phase II results for the current cluster become available (Q4/2015). If the project passes the tests, then an SIS and Facilities Study will be performed after which the project can potentially interconnect as an EO project. If the project is seeking FCDS or PCDS, it will be studied as part of next cluster's Phase II study (Q4/2016) and receive its TPD allocation in Q2/2017.

4.2.3.3 Tests for electrical independence

The ISP timeline is dependent on the timing of the tests for electrical independence. The existing tariff specifies that the electrical independence of a project submitted under ISP needs to be tested on the base case that is being used for the most recent queue cluster. Also, if the current queue cluster studies or earlier queued ISP studies have not yet determined which transmission facilities electrically impacted by the generating facility being tested require network upgrades, and the ISO cannot reasonably anticipate whether such transmission facilities will require network upgrades from other data, then the ISO will wait to conduct the independence analysis until sufficient information exists in order to make this determination. This existing process can introduce delays and uncertainties in the commencement of tests for electrical independence. The ISO is therefore proposing to use Phase I results of the current cluster to test for electrical independence.

The existing Flow Impact Test against "network upgrades" does not delineate between Reliability Network Upgrades (RNUs) and Deliverability Network Upgrades (DNUs) and the practice has been to test against both. Testing for electrical independence based on DNUs is not required since a project requesting FCDS will go through a separate deliverability assessment.

Consistent with the existing tariff, the Tests for Electrical Impact will be performed using the network upgrades identified or reasonably expected to be needed by generating facilities currently being studied in a queue cluster, or as a result of network upgrades identified or reasonably expected to be needed by earlier queued generating facilities currently being studied through the ISP.

Following is a summary of proposed changes to the Tests for Electrical Independence:

a. Flow Impact Test:

   i. The flow impact will only be tested on RNUs where the need for the RNU was related to flow concerns. Testing Area Delivery Network Upgrades (ADNUs) and Local Delivery Network Upgrades (LDNUs) for independence creates unnecessary hurdles to interconnection of projects as EO resources. Due to the nature of RNUs, it is expected that the flow impact test will seldom be required since RNUs are rarely related to flow concerns. If an RNU is related to flow concerns, the flow impact will be tested on the limiting elements that drive the need for RNUs. Flow impact on System Protection Scheme (SPS) RNUs will not be tested.

b. Short Circuit Test:

   i. The existing threshold for the short circuit contribution of the ISP project is 100 ampere. This threshold can be too restrictive in certain areas. A blanket 100 ampere threshold does not serve the intent of testing electrical dependence across a diverse topology. The working group recommends using a proportional threshold instead of an absolute threshold, as follows:

      Short circuit contribution (in aggregate with previous ISP projects in the study area) must be less than 5% of the available capacity AND total fault duty on the identified breaker upgrade must be less than 80% of the nameplate capacity.

c. Transient Stability Test:

   The ISO is proposing this as a new component to the independence test. If the project is connecting in an area where transient stability issues are identified in the current cluster, then it fails the test.

d. Reactive Support Test:

   The ISO is proposing this as a new component to the independence test . If the project is connecting in an area where reactive support needs are identified as RNUs in the current cluster, then the project fails the test.

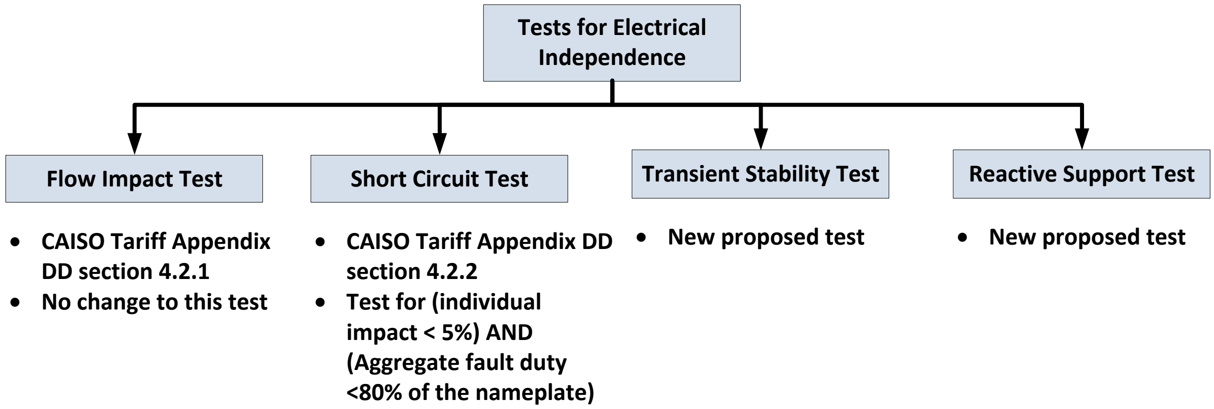

Figure 3 – Proposed Tests for Electrical Independence

Failure to pass the Tests for Electrical Independence: If a project fails any of the Tests for Electrical Independence, the Interconnection Customer will be notified and given an option to be a part of the next cluster.

4.2.3.4 Clarification on behind-the-meter (BTM) expansion and its impact on the NQC

The following modifications/clarifications to the existing BTM expansion section are recommended. Note that although the ISO is presenting this information in the form of draft changes to its existing tariff language, the ISO is doing so only for ease of stakeholder review. The ISO will conduct a tariff stakeholder process for this and other IPE proposals in which the specific tariff language may be revised as necessary in order to best reflect the final proposal. Therefore, stakeholders are encouraged to provide general comments at this time in lieu of line-edit suggestions to the tariff language.

1. Prime Mover Technology

Modify CAISO Tariff, Appendix DD, Section 4.2.1.2 to permit all prime mover technologies – not just wind and solar – to utilize the tariff section, so long as such generating facilities satisfy all of the requirements in the section.

CAISO Tariff, Appendix DD, Section 4.2.1.2 states:

> "This Section 4.2.1.2 applies to an Interconnection Request relating to a behind-the-meter expansion where the existing Generating Facility prime mover is wind technology or solar technology. Such an Interconnection Request submitted under the Independent Study Process will satisfy the requirements of Section 4.2.1 if it satisfies all of the following technical and business criteria for behind-the-meter capacity expansion of a Generating Facility:"

The recommended modification is:

> "This GIP Section 4.2.1.2 applies to an Interconnection Request relating to a behind-the-meter capacity expansion of a Generating Facility. Such an Interconnection Request submitted under the Independent Study Process will satisfy the requirements of GIP Section 4.2.1 if it satisfies all of the following technical and business criteria:"

2. Size of the expansion

CAISO Tariff, Appendix DD, Section 4.2.1.2.(i)(1) states:

> "The total nameplate capacity of the existing Generating Facility plus the incremental increase in capacity does not exceed in the aggregate one hundred twenty-five (125) percent of its previously studied capacity and does not exceed, in the aggregate, one hundred (100) MW."

The recommended modification is:

> "The total nameplate capacity of the existing Generating Facility plus the incremental increase in capacity does not exceed in the aggregate one hundred twenty-five (125) percent of its previously studied capacity, and the incremental increase in capacity does not exceed, in the aggregate including any prior expansions implemented pursuant to this section, one hundred (100) MW."

3. Need for RNUs to be in-service

Modify ISO Tariff, Appendix DD, Section 4.2.1.2.(i)(2) to state that only all reliability network upgrades (not both delivery and reliability network upgrades) for the original generating facility must be placed in service prior to commercial operation of the behind-the-meter capacity expansion.

CAISO Tariff, Appendix DD, Section 4.2.1.2.(2) states:

> "The behind-the-meter capacity expansion shall not take place until after the original Generating Facility has achieved Commercial Operation and all Network Upgrades for the original Generating Facility have been placed in service."

The recommended modification is:

> "The behind-the-meter capacity expansion shall not take place until after the original Generating Facility has achieved Commercial Operation and all Reliability Network Upgrades for the original Generating Facility have been placed in service. An Interconnection Request for a behind-the-meter capacity expansion may be submitted prior to the Commercial Operation Date of the original Generating Facility."

4. Requirement for a separate expansion breaker

Section 4.2.1.2(i)(3) requires that the expanded capacity for the generating facility be placed behind a separate breaker (the expansion breaker) such that the expansion can be metered separately at all times. The working group recommends that this requirement be removed, because BTM expansion has to be behind the main gen-tie breaker for the existing generating facility.

5. Impact of BTM expansion on NQC

Some stakeholders had questions regarding possible increase in Net Qualifying Capacity (NQC) as a result of BTM expansion. The existing process does not allow for any increase in NQC per CAISO Tariff, Appendix DD, Section 4.2.1.2.(i)(5):

CAISO Tariff, Appendix DD, Section 4.2.1.2.(i)(5): states:

> "The processing of an Interconnection Request for behind-the-meter expansion under the Independent Study Process shall not result in any increase in the rated Generating Facility electrical output (MW capacity) beyond the rating which pre-existed the Interconnection Request. Further, the processed Interconnection Request shall not operate as a basis under the CAISO Tariff to increase the Net Qualifying Capacity of the Generating Facility beyond the rating which pre-existed the Interconnection Request."

The recommended modification is:

> "The processing of an Interconnection Request for behind-the-meter expansion under the Independent Study Process shall not result in any increase in the rated Generating Facility electrical output (MW capacity) beyond the rating which pre-existed the Interconnection Request submitted under this section. Further, the monthly value of NQC of the expanded Generating Facility will be limited to the maximum NQC of the Generating Facility during the last three years before the Interconnection Request submitted under this section."

If the proposed BTM expansion project is seeking FCDS/PCDS for the expanded MW capacity, then it will have to submit a new IR into the ISO interconnection queue.

6. Deliverability status of BTM expansion

CAISO Tariff, Appendix DD, Section 4.2.1.2.(ii)(1) states:

> "The Deliverability Status (Full Capacity, Partial Deliverability or Energy-Only) of the capacity expansion is the same as the Deliverability Status specified for the formally studied Generating Facility".

The recommended modification is:

> "The expansion of the Generating Facility pursuant to this Section will not affect the deliverability status of the Generating Facility, including the amount of capacity that is treated as fully deliverable. For example, an Energy Only Generating Facility will remain an

Energy Only Generating Facility and a Full Capacity Deliverability Generating Facility will be treated as having Partial Capacity Deliverability with respect to its pre-expansion capacity.

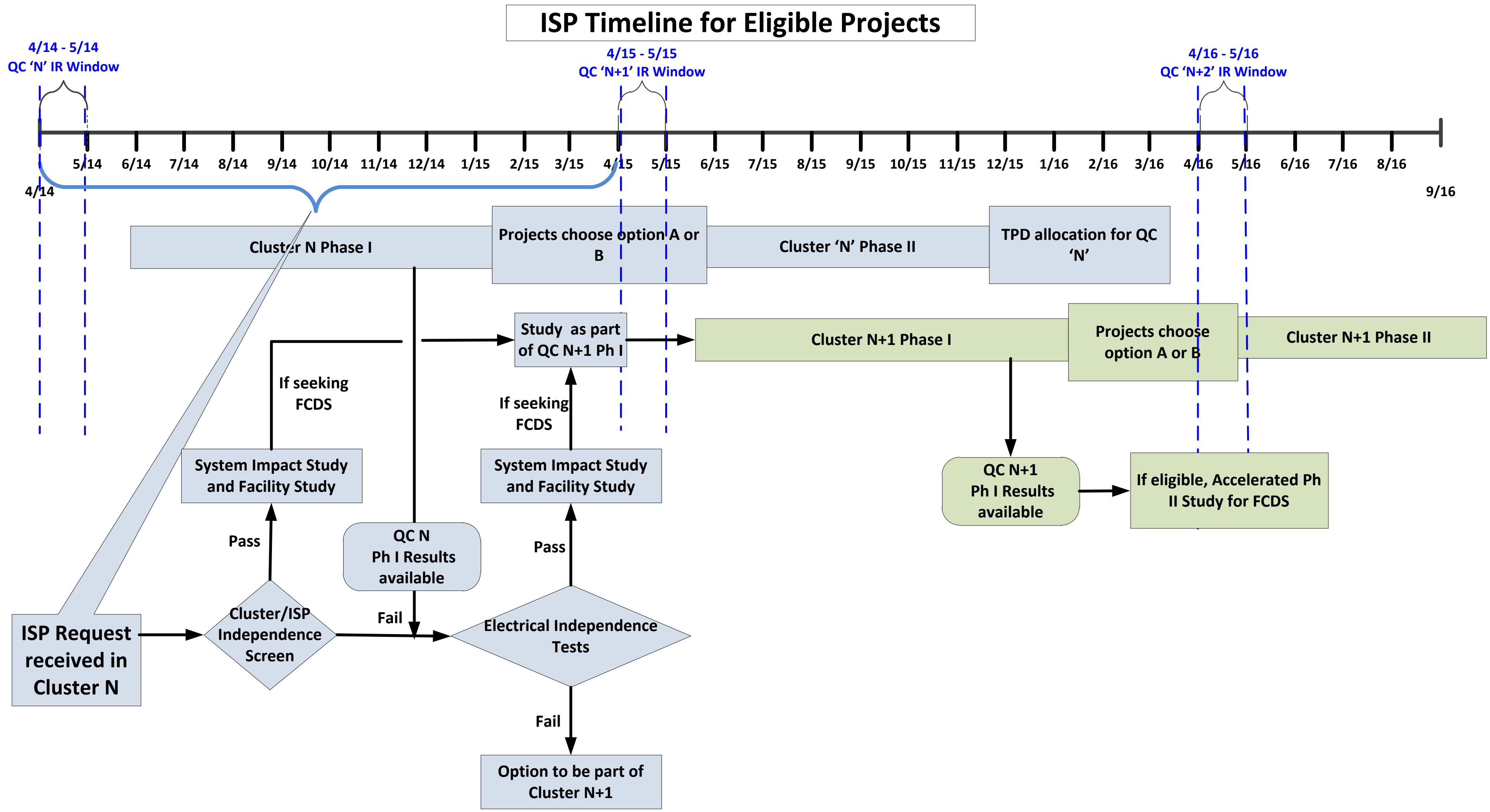

Figure 4 – Proposed ISP Timeline Enhancement

4.3 Topic 5 – Improve Fast Track

The purpose of this topic is to develop Fast Track (FT) screening criteria based on appropriate criteria for projects seeking FT treatment to interconnect the ISO's higher voltage networked transmission system. While clarification of the general tariff process is within the scope of this topic, the current 5 MW FT project size limitation will not be considered for revision. Furthermore, with the ongoing FERC Notice of Proposed Rulemaking on Small Generator Interconnection Agreements and Procedures, FT revisions will not go beyond revising the FT screens as it is anticipated that FERC will be providing future guidance and requirements in the not too distant future that the ISO will need to incorporate into the FT process. Additional revisions to the FT process will be considered after the FERC final ruling on the SGIP NOPR is available.

4.3.1 *FT working group*

In the June 3, 2013 Issue Paper the ISO proposed a FT working group to take on the tasks outlined above. The PTOs perform the studies for reliability network upgrades under the direction of the ISO, and they perform the screening process for projects seeking to qualify for FT treatment. Consequently, the working group includes both engineers and participants with policy expertise from the PTOs and the ISO. This technical input is of vital importance to achieving a workable and technically sound resolution to the issues associated with the FT process. Additionally, participants from the generation development community with both technical and policy expertise participated in the working group.

The work group held its first meeting August 12 and has been generally meeting bi-weekly in an effort to develop a final proposal that can be vetted with the broader IPE stakeholder group.

It is anticipated that the final FT proposal will be completed in early 2014 and be taken to the ISO Board for approval in March 2014.

4.3.2 *Stakeholder comments*

Stakeholder comments received August 22 following publication of the July 18 straw proposal are summarized below.

PG&E – Consider integrating the ISP into the FT process. The ISP would be similar to the FT, such as a hybrid FT process that includes the flexibility to accommodate ISP style characteristics. This could be done by allowing the hybrid FT process to allow projects to apply for deliverability separately through the normal cluster study process. Recommends removal of the 15 BD requirement to provide an Interconnection Agreement. This requirement can create uncertainty for generators successfully interconnecting and meeting their contractual off take obligation as quickly as possible due to inaccurate knowledge of the engineering scope of work and cost estimates to interconnect the project by the PTO. Recommends projects move directly to the supplemental review and the screening process to allow PTOs to conduct sufficient studies that will provide an accurate representation of required Interconnection Facilities and Network Upgrades in the IA.

4.3.3 *Straw proposal*

The proposed revisions to the FT screens and the procedures for the FT process that follows the screening process are described below in the Table 4. The straw proposal includes changes to all screens, the removal of one screen and the addition of two new screens.

Note that although the ISO is presenting this information in the form of draft changes to its existing tariff language, the ISO is doing so only for ease of stakeholder review. The ISO will conduct a tariff stakeholder process for this and other IPE proposals in which the specific tariff language may be revised as necessary in order to best reflect the final proposal. Therefore, stakeholders are encouraged to provide general comments at this time in lieu of line-edit suggestions to the tariff language.

Table 4 – Straw proposal to improve the FT process

Appendix DD-Section No.	Appendix DD-Sub Section No.	Current Tariff Language	Proposed Tariff Language
5.1, 3rd Paragraph.		Initiating the Fast Track Interconnection Request. To initiate an Interconnection Request under the Fast Track Process, and have the Interconnection Request considered for validation the Interconnection Customer must provide the CAISO with: (i) a completed Interconnection Request as set forth in Appendix 1 ; (ii) a non-refundable processing fee of $500 and a study deposit of $1,000; and	Initiating the Fast Track Interconnection Request. To initiate an Interconnection Request under the Fast Track Process, and have the Interconnection Request considered for validation the Interconnection Customer must provide the CAISO with: (i) a completed Interconnection Request as set forth in Appendix 1 ; (ii) a non-refundable processing fee of ***<u>$1000</u>*** and a study deposit of ***<u>$5,000</u>***; <u>Discussion of Changes</u> The work group has proposed some significant changes to the screening process. These changes will help further clarify the intent and the application of the screens. However, this does impact the amount of work and data required for the screening process. The proposed fees should address the additional workload required for the proposed screening process.

Table 4 – Straw proposal to improve the FT process

Appendix DD-Section No.	Appendix DD-Sub Section No.	Current Tariff Language	Proposed Tariff Language
5.2		Within fifteen (15) Business Days after the CAISO notifies the Interconnection Customer that the Interconnection Request is deemed complete, valid, and ready to be studied, the applicable Participating TO shall perform an initial review using the screens set forth in Section 5.3 below, shall notify the Interconnection Customer of the results, and shall include with the notification copies of the analysis and data underlying the Participating TO's determinations under the screens.	Within ***Thirty (30) Business Days*** after the CAISO notifies the Interconnection Customer that the Interconnection Request is deemed complete, valid, and ready to be studied, the applicable Participating TO shall perform an initial review using the screens set forth in Section 5.3 below, shall notify the Interconnection Customer of the results, ***in a report that provides the details*** of the analysis and data underlying the Participating TO's determinations using the screens. Discussion of Changes The group is proposing to increase the time required to perform the initial screening from 15 to 30 Business days. This will ensure that the ISO and PTO have enough time to screen the fast track project for any potential issues. The group is also proposing to issue a report that will provide the details around the application of the screens.
5.3	**5.3.1.2**	For interconnection of a proposed Generating Facility to a radial transmission circuit, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation. For purposes of this Section 5.3.1.2, a line section shall be considered as that portion of a Participating TO's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the transmission line.	For interconnection of a proposed Generating Facility to a radial transmission circuit, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation. For purposes of this Section 5.3.1.2, a line section shall be considered as that portion of a PTO's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the transmission line. ***This screen will not be required for a proposed interconnection of a Generating Facility to a radial line with no load.*** ***In cases where the circuit lacks the telemetry needed to provide the annual peak load measurement data, power flow cases from recently completed***

Table 4 – Straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Sub Section No.**	**Current Tariff Language**	**Proposed Tariff Language**
			<u>Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen.</u> <u>Discussion of Changes</u> The proposal to use the latest Generation interconnection Phase I/ Phase II study base case eliminates the confusion about the type of base case needed for the analysis.
	5.3.1.3	For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 percent of a spot network's maximum load or 50 kW. For purposes of this Section 5.3.1.3, a spot network shall be considered as a type of distribution system found in modern commercial buildings for the purpose of providing high reliability of service to a single retail customer.	***Eliminate this screen.*** <u>Discussion of Changes</u> This screen deals with the interconnection of generation facility on the load side of the spot network protector. We are **proposing to remove the screen** from the current FT screening process. The current screen is not appropriate for the interconnection of generators to an ISO controlled facility. It is more suitable for interconnection at distribution level voltages.
	5.3.1.4	The proposed Generating Facility, in aggregation with other generation on the transmission circuit, shall not contribute more than 10 percent to the transmission circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.	The proposed Generating Facility, in aggregation with other ***active FT*** projects on the transmission circuit, shall not contribute more than ***<u>5 percent</u>*** to the transmission circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership. ***The short circuit study data from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform the scree in this Section.*** <u>Discussion of Changes</u> The proposed 5% threshold provides adequate margin to ensure existing relay settings and coordination are not adversely affected due to the proposed generation in this high level screening process. The Typical margin is 120% which factors in the CT, relay and other modeling errors. The existing 10% limit infringes on the typical margins, and

Table 4 – Straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Sub Section No.**	**Current Tariff Language**	**Proposed Tariff Language**
			could lead to relay misoperations. The lower threshold also ensures safety and reliability in absence of a detailed short circuit study.
	5.3.1.5	The proposed Generating Facility, in aggregate with other generation on the transmission circuit, shall not cause any transmission protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 percent of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5 percent of the short circuit interrupting capability.	The proposed Generating Facility, in aggregate with other generation on the transmission circuit, shall not cause any transmission protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed ***<u>80 percent</u>*** of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds ***<u>80 percent</u>*** of the short circuit interrupting capability. ***The short circuit study data from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform the scree in this Section*** <u>Discussion of Changes</u> The proposed 80 percent threshold provides additional margin to account for the X/R multiplier. This threshold also ensures safety and reliability in absence of a detailed short circuit study.
	5.3.1.6	The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the Point of Interconnection).	The Generating Facility, shall not be permitted to interconnect pursuant to the process set forth in this Section 5 in an area where there are known • transient stability limitations; • *voltage & thermal limitations; or* • *any other known reliability limitations (e.g., existing or new Special Protection Systems)* to generating units located in the general electrical vicinity (*e.g.*, three or four transmission busses from the Point of Interconnection). <u>Discussion of Changes</u> The existing 10 MW threshold was removed and the additional reliability

Table 4 – Straw proposal to improve the FT process

Appendix DD-Section No.	Appendix DD-Sub Section No.	Current Tariff Language	Proposed Tariff Language
			criteria for screening purposes are proposed. This is to ensure safety and reliability of the system in the absence of technical studies.
Proposed Additional Screens			
	5.3.X1	None	The proposed Generating Facility must interconnect to an existing Substation. The proposed interconnection: • Shall be subject to availability of sufficient available infrastructure at the substation, including but not limited to necessary telecommunications equipment. • Taps to an existing transmission line shall not be acceptable and the project will fail the screen.
	5.3.X2	None	The proposed Generating Facility, in the aggregate with other Generating Facilities interconnected to the same transmission circuit, shall not cause the violation of ISO voltage standards, per ISO planning guidelines, on any CAISO controlled facility. Power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen.
	5.3.X3	None	The proposed Generating Facility, in the aggregate with other Generating Facilities interconnected to the same transmission circuit, shall not cause the Power flow on any CAISO-controlled facility to increase by 5 percent, and shall not exceed 80 percent of the same facility's normal rating. Power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen.
5.3.2		If the proposed interconnection passes the screens and no Upgrades are	Delete this provision. Existing Screen 5.3.4 will address this requirement.

Table 4 – Straw proposal to improve the FT process

Appendix DD-Section No.	Appendix DD-Sub Section No.	Current Tariff Language	Proposed Tariff Language
		reasonably anticipated, the Interconnection Request shall be approved. Within fifteen (15) Business Days thereafter, the Participating TO will provide the Interconnection Customer with a Small Generator Interconnection Agreement for execution.	<u>Discussion of Changes</u> The group is proposing to eliminate this requirement . The current proposal is to perform both System Impact and Facilities studies for projects failing the screen, and to perform only a Facilities Study for projects passing the screen. . This proposal will ensure that the ISO and PTO accurately reflect upgrade costs in the SGIA.
5.3.3.		If the proposed interconnection fails the screens and no Upgrades are reasonably anticipated, but the CAISO and Participating TO determine that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Participating TO shall, within Fifteen (15) Business Days, provide the Interconnection Customer with a Small Generator Interconnection Agreement for execution.	If the proposed interconnection fails the screens ***then, in accordance with section 5.2, the ISO and applicable Participating TO will provide the Interconnection Customer with copies of all data and analyses underlying this conclusion. Also, in accordance with section 5.4, the ISO and Applicable Participating TO will offer to convene a Results meeting***. <u>Discussion of Changes</u> It was hard for the group to think of a potential scenario that fits the situation described in this provision. The proposed language better addresses the consequences of failing the screens.
5.4		Customer Options Meeting	Change the name to **Results meeting**.
	5.5.1	Within ten (10) Business Days following receipt of the deposit for a supplemental review, the CAISO and Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably.	Within ***Fifteen(15)*** Business Days following receipt of the deposit for a supplemental review, the CAISO and Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably. ***If a Generating Facility has passed the screens set forth in Section 5.3, the ISO and Applicable Participating TO shall perform a facilities study for that Generating Unit.*** <u>Discussion of Changes</u> The WG determined that to interconnect a FT project that passes the screens a facilities study will be needed to define the scope of the interconnection that will be reflected in the SGIA. The Supplemental Review section of the tariff

Table 4 – Straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Sub Section No.**	**Current Tariff Language**	**Proposed Tariff Language**
			does not specify the types of studies that would be offered to be performed when a FT project fails the screens. The WG considered defining the studies as being similar to system impact and facility study, and/or a hybrid of the two studies. While the tariff will not be changed to define the type of studies to be performed the timeline is proposed to be extended to 15 Business days to accommodate the type of studies envisioned.

4.4 Topic 12 – Consistency of suspension definition between serial and cluster

The ISO had planned to present its proposal for topic 12 at the ISO Board meeting on September 12, 2013, along with its proposals for topics 6-11. However, in advance of the Board meeting the ISO received a letter from the Large-scale Solar Association (LSA) raising a concern with approval of the ISO's proposal for topic 12. Due to this concern, ISO management withdrew this item from the Board agenda to allow further discussions to take place.

After giving further consideration to this topic and its proposal, the ISO has determined to withdraw this topic. Since the generator interconnection agreement is a three-party agreement, any party may request changes during negotiations. Thus, it is the ISO's intention to seek incorporation of this change on a case-by-case basis as part of its negotiations on the applicable LGIAs.

4.5 Topic 13 – Clarity regarding timing of transmission cost reimbursement

4.5.1 *Background*

On November 30, 2011, the ISO filed proposed tariff revisions to its generator interconnection process following the completion of the Generator Interconnection Procedures Phase 2 ("GIP 2") stakeholder process.[16] Item #6 in the GIP 2 effort addressed repayment of interconnection customer funding for network upgrades associated with a phased generating facility. That provision, Section 12.3.2.2 of the ISO's Generator Interconnection Procedures, provides that upon commercial operation of a phase of a generating facility, the generator is entitled to repayment of the costs of the network upgrades associated with that phase, provided that the network upgrades are in-service.

This "in-service" requirement for repayment is not explicitly included in the ISO's tariff provision regarding the repayment of network upgrades for non-phased facilities, which refers only to the requirement that a generator have achieved commercial operation in order to qualify for repayment of network upgrade costs funded by that generator.

LSA and CalWEA both urged FERC to reject the ISO's proposed in-service requirement for repayment of network upgrade costs for phased facilities. These entities argued that this requirement violated Commission precedent, reasoning that the Commission has never required any other conditions to repayment other than commercial operation of the generator.

In its January 30, 2012 order on the GIP 2 amendment, the Commission rejected this argument, in particular the notion that "the achievement of commercial operation is the sole condition required before an interconnection customer becomes eligible for repayment."[17] Instead, the Commission explained that in order to ensure that an interconnection customer "bears an appropriate level of risk that network upgrades associated with its generating facility may become unnecessary should the interconnection customer's facility becomes commercially infeasible, the Order No. 2003 series of orders required as a general policy that repayment begin once transmission service to deliver the output of the interconnection customer's generating facility is provided."[18] Because it found that repayment of network upgrades is appropriately tied to the utilization of the transmission provider's network, the Commission concluded that the ISO's proposal to require that network upgrades associated with a particular phase be in service prior to the generator being eligible to receive repayment for the costs of those upgrades was just and reasonable, and consistent with the Commission's interconnection policies.

Despite the fact that the Commission decided this matter in the context of phased facilities, the Commission did not state or suggest that its reasoning was limited to phased facilities, nor is there any logical reason that it would be. As with a phased facility, if certain upgrades associated with a non-phased facility have not been placed in service, those upgrades are not being utilized by the generator. Therefore, per FERC's reasoning that the repayment of network upgrades is appropriately tied to the utilization of those upgrades, the ISO does not believe that there is a

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[16] FERC Docket No. ER12-502.
[17] 138 FERC ¶ 61,060 (2012) at P 53.
[18] *Id*.

sound basis for retaining the rule that non-phased generators need only achieve commercial operation in order to be eligible for repayment for all network upgrade costs up-front funded by the generator.

Although the ISO explained in pleadings submitted in the GIP 2 proceeding that it interpreted the tariff provision regarding non-phased facilities as inherently including an in-service requirement, the Commission, in a subsequent order clarifying its GIP 2 order, rejected this interpretation.[19] The Commission explained that the "plain language" of the ISO tariff states that eligibility for repayment for non-phased generators is based solely on the commercial operation date of the generator. The Commission indicated that if the ISO interprets this provision differently, the ISO should "file revised tariff language to clarify the timing of refunds associated with a non-phased project."

Based on the Commission's GIP 2 clarification order, the ISO proposed, in its April 12, 2013 tariff amendment in FERC Docket No. ER13-1274, to revise Section 11.4.1 of Appendices CC and EE to remove language in *pro forma* generator interconnection agreements that require an interconnection customer with a non-phased[20] generating facility to wait until the in-service date of corresponding network upgrades prior to being entitled repayment for the cost of those network upgrades.[21] The ISO explained in that proceeding that its proposed changes to Section 11.4.1 of Appendices CC and EE only serve to implement FERC's GIP 2 clarification order and remove any ambiguity from the ISO tariff regarding what conditions apply to repayment of network upgrades cost for non-phased projects.

Thus, under the ISO's existing rules, the timing of transmission cost reimbursement for phased and non-phased projects is as follows:

- For phased projects, transmission cost reimbursement does not begin until the commercial operation date of each completed phase and all network upgrades to support the desired level of deliverability for each completed phase are in service.
- For non-phased projects, transmission cost reimbursement begins upon the commercial operation date of the generating facility.

[19] *Cal. Indep. Sys. Operator Corp.* 140 FERC ¶ 61,168 at P 7, citing ISO tariff, Appendix Y, § 12.3.2.1

[20] A phased generating facility is a generating facility that is structured to be completed and to achieve commercial operation in two or more successive sequences that are specified in the generator interconnection agreement, such that each sequence comprises a portion of the total megawatt generation capacity of the entire generating facility. In contrast, a non-phased generating facility is a generating facility that is structured to be completed and to achieve commercial operation in one sequence.

[21] Appendix CC of the ISO's tariff is a Large Generator Interconnection Agreement for Interconnection Requests in a Queue Cluster Window that are tendered a Large Generator Interconnection Agreement on or after July 3, 2010. Appendix EE of the ISO's tariff is Large Generator Interconnection Agreement for Interconnection Requests Processed under the Generator and Deliverability Allocation Procedures (GIDAP).

4.5.2 *Summary of July 18 straw proposal*

In the July 18 straw proposal the ISO stated that for customers who have already received a generator interconnection agreement, regardless of whether they represent phased or non-phased projects, the ISO does not believe it appropriate to consider modifications to these existing rules in the IPE initiative. That said, the ISO did indicate a willingness to consider as part of this initiative whether, beginning with the appropriate Queue Cluster depending upon timing of FERC approval, cost reimbursement for network upgrades should be harmonized for both phased and non-phased projects by requiring, for both types of projects, that a generator have achieved commercial operation and that the network upgrades are in service in order for cost reimbursement to commence.

Thus, on a going forward basis, the ISO indicated that it is open to at least considering other approaches. However, a review of stakeholder comments received prior to publishing the July 18 straw proposal did not reflect any agreement among stakeholders on what that approach should be.[22] Some stakeholders asserted that eligibility for cost reimbursement for all projects should commence only with the completion of two events: (1) the commercial operation date of the generation facility and (2) the in-service date of required network upgrades for the facility. In contrast to this, other stakeholders hold the view that eligibility for cost reimbursement should require only that the generating facility has achieved commercial operation. Also, at least one stakeholder asserted that if there is to continue to be differential treatment between phased and non-phased projects, that a phased generating facility with all phases completed should be treated the same as a completed non-phased project is under existing rules (i.e., eligible for reimbursement solely based on the commercial operation date of the completed generating facility).

Based on this stakeholder feedback, the ISO proposed the following options, on a going forward basis, in the July 18 straw proposal for stakeholder consideration:

- Status quo. Make no changes to the existing rules on a going forward basis. This would continue the differential treatment between phased and non-phased generating facilities.
    - If this rule was to be retained going forward, then a sub-issue is whether a phased project that has completed all its phases should be treated, at that point, as a non-phased project for purposes of cost reimbursement, and therefore eligible to receive reimbursement for any remaining costs that it funded commencing upon the COD of the final phase.
- Eligibility for cost reimbursement should commence upon the completion of two events: (1) the commercial operation date of the generating facility or phase of a phased generating facility and (2) the in-service date of required network upgrades for the generating facility or phase of the upgrades for a phased generating facility.

[22] These were written stakeholder comments received on June 25 in response to the June 3 IPE issue paper.

The ISO requested that, in the stakeholder comments due on August 22 in response to the July 18 straw proposal, stakeholders express their preference for a particular option and explain their reasons why.

4.5.3 *Stakeholder comments*

Stakeholder comments received August 22 following publication of the July 18 straw proposal are summarized below.

California Public Utilities Commission ("CPUC") staff – CPUC staff believes that modifications to existing tariff requirements should apply to projects not yet tendered an interconnection agreement and that projects having already made security deposits should not be subject to less favorable conditions than exist under current tariff requirements. Phased projects should not be treated unfavorably relative to non-phased projects when it comes to reimbursement. Starting reimbursement upon reaching commercial operation appears reasonable as does partial reimbursement upon a phase reaching commercial operation. This would motivate timely completion of transmission. If it can be demonstrated that this would place undue financial burden on transmission owners when transmission completion is delayed, then delaying partial reimbursement until the transmission is completed might be considered.

California Wind Energy Association ("CalWEA") – CalWEA believes that reimbursement for either a phased or non-phased project should start upon the project reaching commercial operation and without regard to the completion of the network upgrades themselves. If the project reaches COD before the network upgrades have been fully implemented, then it should not be asked to post financial security for the implementation portion of the upgrades that have not yet been started or are not complete.

Independent Energy Producers ("IEP") – IEP supports the status quo, triggering repayment on the COD of the customer's generation only and not on the combination of generator COD and transmission upgrade in service date. Generators would be placed at risk if their repayment for funding transmission upgrades were to be tied to the in service date of network upgrades over which they have no direct control.

Large-scale Solar Association ("LSA") – LSA opposes extending the same treatment to non-phased projects as for phased projects. LSA argues that there is no justification for retention of interconnection customer funds for years after the generating facility reaches commercial operation, especially when the customer has no control over the timing of transmission upgrade construction. LSA suggests that if any change is made, it should not apply to any project that has posted financial security at the time that the change is approved. Though LSA does not agree with FERC's decision with respect to phased projects, LSA does not see any purpose in raising it again so soon. Given the choice of either extending the same treatment to non-phased projects or the status quo, LSA supports the status quo. If any change is made, it should not apply to any project that has posted financial security at the time the change is approved. LSA proposes that phased projects with all phases completed should be treated the same as completed non-phased projects—i.e., the former should be eligible to begin reimbursement upon the COD of the last phase, without waiting for network upgrade completion. Based on its belief that the purpose of up-front funding by generators is to demonstrate project viability and that the upgrades will be used and useful, LSA believes that refunds should be started and payments stopped for unfinished network upgrades when a generation project is complete (since the project has demonstrated its viability). LSA proposes the following for all completed projects (whether phased or non-phased):

- Reimbursement would begin at the COD of the entire project (for non-phased projects) or no later than the last phase (for phased projects) for the amounts paid up to that point. Reimbursement would be spread on a levelized basis over the next five years.
- The customer would continue to pay network upgrades each month for new construction. Starting in the following month, the amount paid the prior month will begin to be refunded over the next five years. This process would continue for payments made each month until five years after all the network upgrades are completed.

NRG Energy ("NRG") – NRG believes that reimbursement should begin when the generating project reaches commercial operation. Waiting to begin reimbursement until the network upgrades are completed does not create an incentive for the participating transmission owner to complete the upgrades in a timely fashion.

Pacific Gas & Electric Company ("PG&E") – PG&E supports clarifying that both phased and non-phased projects should become eligible to receive transmission cost reimbursement starting at COD, up to the costs billed to the customer by the participating transmission owner at the time COD is achieved. PG&E recommends two options for cost reimbursement of post-COD work at the discretion of the generator:

- The customer pre-funds the remaining work at COD and begins to receive reimbursement of the fully funded amount starting at COD; or,
- The customer continues to pay for work as billed by the participating transmission owner post-COD, which would accrue until the network upgrades are complete, at which point a second reimbursement period would begin for the post-COD work.

San Diego Gas & Electric ("SDG&E") – SDG&E's policy is to reimburse advanced construction funds cost in one lump sum upon the generating project reaching commercial operation. SDG&E believes that FERC's rationale for requiring customers to advance construction funds is that it provides the customer with incentives to (i) site generation projects at locations that tend to minimize the amount of construction funds that must be advanced (i.e., where there is adequate existing or planned transfer capability) and (ii) bring the generation projects on-line since the COD for the generation project must be determined before the advanced construction funds are reimbursed.

SDG&E does not believe it is necessary for all of the network upgrades to be in place before the advanced construction funds are reimbursed. SDG&E believes that utilities have ample financial capacity to fund the construction of network upgrades for which the advanced construction funds were reimbursed to the customer prior to completion of the network upgrades identified in the interconnection agreement.

Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside ("Six Cities") – The Six Cities believes that eligibility for cost reimbursement for both phased and non-phased projects should require both (i) that the project have achieved commercial operation and (ii) that the required network upgrades are in service. The Six Cities believes that reimbursement for up-front payments associated with network upgrades should not begin until those upgrades are actually placed into service.

Southern California Edison ("SCE") – SCE believes that reimbursement should commence with the completion of two events: (i) the commercial operation date of the generating facility (or phase of the facility for phased projects) and (ii) the in-service date of required network upgrades for the generating facility (or phase of the facility for phased projects).

4.5.4 *Straw proposal*

A review of the August 22 stakeholder comments does not indicate that there is consensus on either of the potential options offered in the July 18 straw proposal paper. Some stakeholders prefer the status quo or some variant of the status quo, while others maintain that eligibility for cost reimbursement should commence upon the completion of both the commercial operation date of the generating facility or phase of a phased generating facility and the in-service date of required network upgrades for the generating facility or phase of the upgrades for a phased generating facility.

Despite this lack of consensus, the ISO has nevertheless developed a straw proposal in an attempt to establish a common approach for phased and non-phased generating facilities with regard to commencement of reimbursement for network upgrade costs. This straw proposal is an attempt to strike a balance between a number of considerations:

1. Alignment with the policies and requirements of the Order No. 2003 series of orders that repayment for transmission assets begin once those assets are utilized to deliver the output of the interconnection customer's generating facility
2. Elimination of the differential treatment of phased and non-phased projects with respect to timing of reimbursement. Some stakeholders have argued that there is no basis for the difference in treatment for phased versus non-phased generating facilities with respect to commencement of transmission credits.
3. Further incentivize timely completion of upgrades by the PTO.

4. Avoid retention of interconnection customer funds for an unreasonable number of years after the COD of the generating facility, or phase of the facility for phased projects.

Thus, the ISO proposes that reimbursement commence once the following two conditions are met:

1. The generating facility, or phase of the facility for phased projects, achieves commercial operation; and,
2. The earlier of: (i) the in-service date of the required network upgrades for the facility or phase of the facility; and (ii) a specified period of time after the facility or phase of the generating facility has achieved commercial operation. The ISO is considering two years as the specified period of time; but, invites stakeholders to suggest other alternatives.

In addition, the ISO proposes that in instances where some of the required network upgrades are in service and others are not, reimbursement for the in-service upgrades can commence upon commercial operation of the generating facility or phase. For example, if RNUs are in service at the time a generator achieves commercial operation but DNUs are not, reimbursement for the RNUs would begin at that time, while reimbursement for the DNUs would commence per the two conditions articulated above.

Lastly, the ISO proposes to apply these new rules on a going forward basis. The ISO believes that the appropriate balance between harmonizing the repayment rules and existing customer expectations is to apply this new policy beginning with customers who have not yet received a generator interconnection agreement. However, in order to avoid a situation in which customers in the same cluster, or even in the same study group, could be subject to different repayment rules, the ISO proposes to apply these new rules beginning with all customers in the first cluster in which all projects have not yet been tendered a generator interconnection agreement at the time of FERC approval of the ISO proposal on this topic.

The ISO invites stakeholders to comment on this straw proposal.

4.6 Topic 14 – Distribution of forfeited funds

The ISO tariff currently provides that funds forfeited by interconnection customers that withdraw from the generator interconnection queue, including both study deposit funds and interconnection financial security (IFS) postings, will be redistributed on an annual basis to scheduling coordinators. Many stakeholders argued that this approach should be changed in the current initiative. In the July 18 paper the ISO identified a number of alternative approaches for redistributing forfeited funds. On August 22 stakeholders submitted written comments on these alternatives. In the the present paper the ISO responds to stakeholders' comments and presents two alternative straw proposals on this topic for stakeholder consideration.

4.6.1 *Amount of forfeited funds 2009-2013*

Stakeholders have requested that the ISO provide the dollar amounts of study deposits and IFS funds that have been forfeited and distributed to scheduling coordinators. Table 6 below shows forfeited study deposits and financial security amounts since 2009. The total forfeited amounts collected since 2009 is $55.1 million, including interest. This amount comprises approximately $30.6 million in study deposits and approximately $24.5 million in financial security. At this point the amounts for 2009-2011 have been distributed to scheduling coordinators; the 2012 amounts have not yet been distributed, though the ISO has submitted a filing to FERC to distribute these funds to scheduling coordinators and is awaiting FERC approval. When the current initiative is concluded the ISO intends to seek FERC approval to distribute the 2013 forfeited funds in accordance with the new approach that results from this initiative.

Table 6 – Amount of forfeited funds 2009-2013

Forfeited Funds	Total
Forfeited Study Deposits – 2013*	$1,000,000
Forfeited Interconnection Financial Security Deposits – 2013*	$14,270,794
	$15,270,794
Forfeited Study Deposits – 2012**	$15,598,149
Forfeited Interconnection Financial Security Deposits – 2012**	$4,143,612
Forfeited Interconnection Financial Security Deposits – 2011** (collected in 2013)	$423,264
	$20,165,025
Forfeited Study Deposits – 2011	$1,399,899
Forfeited Interconnection Financial Security Deposits – 2011	$4,931,615
	$6,331,514
Forfeited Study Deposits – 2009	$11,350,286
Forfeited Study Deposits – 2010	$1,209,879

Table 6 – Amount of forfeited funds 2009-2013

Forfeited Funds	Total
Forfeited Interconnection Financial Security Deposits – 2010	$805,819
	$13,365,984
Total Forfeited Amounts	$55,133,317

** Estimated 2013 collections*

***2012 forfeited funds pending FERC approval*

4.6.2 *Stakeholder Comments*

CalWEA stated that the ISO should use all forfeited funds to pay for network upgrades resulting from the interconnection study processes.

The CPUC offered a number of suggestions: (a) Use study deposits to offset impacts on customers whose study costs increase, or to offset study costs generally. (b) Use security deposits to offset impacts on customers whose deposits increase, or to offset TAC generally. (c) Use the funds to offset costs of particular transmission projects related to the forfeited funds. (d) If FERC ruling identifies stranded unrecoverable costs associated with forfeiture, funds should be used to offset these costs. (e) Consider refunding funds to the interconnection customer for capacity later used.

IEP stated that the funds should be applied first to entities impacted by withdrawal, then to offset TAC, either on a system-wide basis or in the PTO area where withdrawal occurred.

LSA stated that forfeited study deposits should offset study costs for projects in the same cluster that remain in queue, and that forfeited financial security funds should be used to reimburse interconnection customers whose reliability network upgrade costs exceed the GIDAP reimbursement limits.

NRG stated that forfeited funds should offset impacts of withdrawn projects on costs incurred by other customers in the same cluster.

PG&E stated that the funds should be used to hold harmless generators, ratepayers, and PTOs affected by the project withdrawals. Any excess funds should be used to cover negotiation costs of interconnection agreements, and any remaining excess to reduce TAC by PTO area.

SCE stated that the funds should reduce TAC in the PTO territory of the withdrawn projects.

SDG&E stated that the funds should reduce TAC system wide.

Silverado stated that study deposits should offset study costs for projects in the same cluster that remain in queue, and that forfeited security funds should be used to fund costs of shared network upgrades that are still needed for projects in the same cluster.

Six Cities stated that the funds should be used to offset cost of network upgrades associated with the withdrawn project, if still needed. Any excess funds should offset costs of other network upgrades for same cluster; any further excess to offset TAC system-wide.

4.6.3 *ISO responses*

As described more fully in the next subsection, one of the two ISO straw proposals is to redistribute forfeited funds to transmission ratepayers via offsets to the high voltage (or "regional" in accordance with the terminology of FERC Order 1000) transmission revenue requirements (HVTRR) recovered through the ISO's TAC. Nearly all of the stakeholder comments expressed support for using at least a portion, if not all of the funds, to reduce the costs paid by ratepayers for transmission facilities. Some comments supported the very broad allocation of these funds as the ISO now proposes, whereas others proposed more refined allocations in order to target funds to offset costs of specific facilities or costs in specific PTO service areas.

Under Option A below, the ISO proposes the broadest allocation of these funds for simplicity and to avoid creating any perverse incentives. Regarding simplicity, it is important to realize that the amounts of forfeited funds collected annually are relatively minuscule compared to the combined size of the annual system-wide HVTRRs for all the PTOs. For this reason the ISO believes that the complexity of trying to target forfeited funds to offset costs of specific network upgrades would render the effort involved greater than the benefits. At a minimum such targeting would create timing problems, as the funds forfeited by withdrawn projects would often become available before the final cost of the targeted network upgrades is known. Such an approach would therefore require complex tracking of forfeited funds against specific network upgrade costs potentially over several years. The same problem would arise in trying to reimburse the customer that forfeited the funds if the associated transmission capacity is used by later projects. The ISO believes that the amount of funds involved makes these approaches less desirable given the effort required to conduct such detailed tracking.

Regarding perverse incentives, a general principle the ISO advocates in considering all the options is to avoid having specific entities benefit from the failure of specific projects in the queue. A related incentives principle is to avoid using the forfeited funds to alter the balance of incentives for interconnection customers that were developed in prior initiatives to enhance or reform the interconnection procedures. These principles apply to a number of the suggestions offered by stakeholders, such as applying the funds to offset study costs or security deposits for other projects in the same cluster, or to pay down costs of reliability network upgrades that exceeded the reimbursement cap established in the GIDAP.

Regarding the use of forfeited funds to offset adverse impacts on interconnection customers remaining in queue or on PTOs, the ISO offers Option B described below.[23]

4.6.4 *Straw proposal*

The ISO offers two alternative straw proposals for stakeholder consideration, and requests stakeholders to comment on the pros and cons and their preferences for either of these alternatives.

Option A. Use the funds to reduce the high voltage transmission access charge.

Under Option A the ISO would redistribute forfeited funds to transmission ratepayers via offsets to the high voltage transmission revenue requirements (HVTRR) recovered through the ISO's TAC. For this purpose the ISO would utilize the credit mechanism allowed in the transmission revenue balancing accounts (TRBA) of the PTOs for the HVTRR, as described below, and would allocate pro rata shares of the forfeited funds to each PTO in proportion to the ratio of each PTO's HVTRR to the total of all PTOs' HVTRR at the time existing funds are allocated to the TRBA.[24]

The TRBA is used to track monies that the PTO receives towards its TRR outside of the TAC payments from the ISO. For a non-load serving PTOs, the TRBA also includes amounts by which the TAC collections, from loads and exports, each month may exceed or fall short of the amount required to exactly recover their HVTRR.[25]

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[23] On the general idea of using forfeited funds to offset costs of studies or other interconnection activities that are recovered through the GMC, the ISO realized that it would not be prudent to rely on this highly uncertain source of funds to cover the costs of specific business activities that must be performed on a regular ongoing basis. Even if the ISO did adopt such a provision, there would need to be a backup funding source for the same activities in years when the forfeited funds were not sufficient

[24] Today, the ISO uses the TRBA credit mechanism to allocate excess funds from wheeling service, LCRIG with respect to a LCRIF, revenues from Existing Rights, and the annual congestion revenue rights balancing account to offset the HVTRR of the PTOs. (See Appendix F, Schedule 3, Section 6.1(b) of the ISO Tariff, and the definition of Transmission Revenue Credit)

[25] The reason for this additional nuance for the non-load serving PTOs' TRBA is that they do not have a GWh load as a basis for calculating their monthly shares of TAC revenues, and instead are expecting to receive 1/12 of their filed annual HVTRR per month. However, when the TAC revenues are allocated to the PTOs on a monthly basis, they are first allocated (a) to the load serving PTOs based on the actual GWh load for that PTO in that month times the HV Utility Specific Rate and (b) to the non-load serving PTO in proportion to their HVTRR. Then, the sum of (a) and (b) is compared to the total TAC for the month and the difference is allocated to the load-serving PTOs in proportion to

The TRBA works on an annual cycle that runs from October 1 to September 30, so that the PTO can include the TRBA results in its annual filing at FERC for its TRR to be recovered the next year. Under the present proposal, the ISO would distribute the forfeited funds to PTOs each year prior to September 30, in time to be included in the PTOs' FERC filings for the coming year's TRBA adjustment to the TRR. In order to minimize the delay between when the funds are forfeited and when they are reflected in TAC reduction, the ISO proposes to accumulate and re-distribute forfeited funds on an annual cycle that runs from July 1 to June 30.

The following example illustrates how this annual procedure would work in practice. Consider the year from July 1, 2014 through June 30, 2015, and suppose that a total of $X were forfeited during that period by interconnection customers dropping out of the ISO queue. The ISO would distribute pro rata shares of these funds to each PTO in proportion to the amount of its HVTRR as of June 30, 2015. The PTO would then account for these funds in its TRBA that closes on September 30, 2015, to be reflected in the PTO's FERC filing of its TRBA, which would become effective January 1, 2016 for purposes of establishing the TRR amount that would be collected via the TAC during 2016.

The example above is a good illustration of how this proposal would work on an annual basis going forward. For the first year, however, the ISO proposes to accumulate all the funds forfeited from January 1, 2013 through June 30, 2014 and distribute these to the TRBA cycle that closes on September 30, 2014, to each PTO in proportion to its HVTRR as of June 30, 2014.

Finally, the ISO proposes not to make any revisions or adjustments to the allocation of forfeited funds after the shares for each PTO have been determined based on the June 30 HVTRR amounts in the relevant year.[26]

Option B. Use the funds to offset adverse impacts of project withdrawals on customers remaining in queue and PTOs.

In response to questions raised in the context of discussions on topics 1 and 2 of this IPE initiative, the ISO explained how the annual reassessment study implemented under the GIDAP could result in modified cost responsibilities for projects in queue.[27] In particular, when some projects withdraw from the queue or downsize, the reassessment study may indicate needed changes to the network upgrades required to meet the needs of projects remaining in queue, and this could

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HVTRR of load-serving PTOs. As a result, the monthly amounts paid to each non-load serving PTO may not exactly equal 1/12 of its filed annual HVTRR.

[26] If the PTO has a HVTRR in effect on June 30 that is subject to refund, the ISO is proposing to allocate the forfeited based on that effective rate and ***not*** reallocate the forfeited funds once the PTO's HVTRR is approved by FERC.

[27] The discussion provided here is intended only as a brief summary of certain aspects of the reassessment study and its potential outcomes. For a more complete explanation, see the ISO's technical bulletin on this subject, *Technical Bulletin: Reassessment Process Reallocation of Cost Shares for Network Upgrades and Posting* which can be found on the ISO website at: http://www.caiso.com/Documents/TechnicalBulletin_GIDAP-ReassessmentProcessReallocation-CostShares-NetworkUpgrades-Posting.pdf

result in modifications to the allocation of costs among remaining projects. In general the ISO expects that the reassessment would allow some upgrades to be reduced or eliminated, thereby lowering overall cost responsibilities. But this may not always be the case.

The potential impacts on remaining interconnection customers and PTOs are best explained through an example. Suppose Project 1 in the queue has a cost cap for network upgrades of $10 million as a result of its Phase I and Phase II studies. At this point, $10 million is also Project 1's cost responsibility. Then some projects in Project 1's electrical area drop out or downsize, and the reassessment study reveals that a network upgrade can be eliminated, reducing Project 1's cost share to $6 million. Next, in the following year another project in the area drops out, but this time the reassessment study reveals that no reduction is network upgrades is possible. Due to the fact that the network upgrade costs are not reduced while there are fewer remaining projects to fund them, Project 1's cost share will increase, although its maximum cost responsibility of $10 million will remain the same.

In this scenario, suppose Project 1's new cost share is $8 million. In this case Project 1 sees a $2 million increase in its allocated costs over the prior year's reassessment study. Some stakeholders have argued that this would constitute an adverse impact on Project 1 as a result of withdrawals from the queue, and that the ISO should implement provisions to mitigate the risk of such impacts. Option B of the proposal would utilize $2 million from the available forfeited funds to cover the increase in Project 1's cost responsibility.

In another scenario suppose Project 1's new cost share is $12 million. The $10 million cost cap established for Project 1 would still apply, so Project 1 would see an increase in its cost share back up to its cost cap, while the PTO would have to cover the additional $2 million. In this case, Option B of the proposal would utilize $6 million from the available forfeited funds to cover the increase in Project 1's cost responsibility as well as the gap that would otherwise fall to the PTO.

Of course, Option B would be effective only to the extent there are sufficient forfeited funds to cover these impacts. To maximize the availability of such funds to cover these impacts, the ISO proposes under Option B not to redistribute any of the forfeited funds through some secondary distribution method, but instead to retain all forfeited funds in an ongoing account to cover such impacts of the annual reassessment study. In a situation where the amount of available funds was not sufficient to fully offset all the targeted impacts of one year's reassessment, the ISO suggests allocating the available funds to all affected customers and PTOs in a pro rata fashion, in proportion to the amount of the financial impact on each party. As a possible variant of the ongoing account concept, the ISO suggests monitoring the rate at which these retained funds were being utilized, and in the event that a significant under-utilized surplus is accumulated, distributing the surplus in accordance with Option A above.

The ISO invites stakeholders to comment on both of these alternative straw proposals.

4.7 Topic 15 – Material modification review

Although this topic started as an inquiry about project requests to make inverter/transformer changes without having to go through material modification review, the ISO broadened the topic somewhat in response to stakeholder comments. As a consequence, the title of this topic has been modified to more broadly encompass the material modification review process rather than remain limited to inverter/transformer changes. Stakeholders want to allow certain project revisions without a need for a material modification assessment and are looking for more transparency in the modification process. Over the past year, the ISO and PTOs have put in place significant process structure around requests for modification and are now in a position to better communicate that structure to stakeholders and commit to developing language in this initiative to be included in the BPMs. Once developed, the ISO would propose to add the language to the BPM for GIP and similar language in the new BPM for the GIDAP.

4.7.1 *July 18 straw proposal*

The ISO's straw proposal on this topic is to develop BPM language that can be added to the GIP and GIDAP BPMs to provide greater transparency regarding the modification review that is performed by the ISO and PTO.

4.7.1.1 Proposed BPM development timeline

The ISO held a stakeholder call on October 29 with interested stakeholders to discuss modifications that stakeholders want to see as "automatic" and what "automatic" means. This stakeholder call was announced by market notice dated October 22.[28] Based on that discussion, the ISO is developing draft BPM language regarding the modification process with a target posting date of November 18, 2013. Stakeholder comments would be due to the ISO on December 9th and a stakeholder call to discuss the comments on December 16, 2013 from 1:00pm to 2:30pm. This schedule will allow the ISO to then propose draft BPM language in the BPM change management process starting in January 2014 with a target approval in March 2014.

[28] http://www.caiso.com/Documents/InterconnectionProcessEnhancementsTopic15CallOct29_2013.htm