Interconnection Process Enhancements

Straw Proposal

July 18, 2013

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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 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 a 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), the ISO offered straw proposals in the June 3 paper. For the remaining eight topics 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 expects to take these proposals to the September meeting of the ISO Board of Governors and will file the associated tariff amendments before the end of the year. As a result, topics 6-12 are not addressed in this straw proposal paper.

In this paper, the ISO addresses topics 1-5 and 13-15. The ISO is prepared to offer straw proposals on three topics (topics 1-3)[2] relating to the sizing and structuring of projects in the queue. The ISO

[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 three topics are (1) future downsizing policy; (2) disconnection of first phase of project for failure of second phase; and, (3) clarify tariff and GIA provisions related to dividing up GIAs into multiple phases or generating projects.

expects to resolve these three topics this autumn and is targeting the December meeting of the ISO Board for presentations of its final proposals on these three topics. The ISO also offers a straw proposal for topic 15 (inverter/transformer changes) in this paper; however, implementation of this proposal will be through the business practice manual change process rather than through tariff changes; where needs for tariff changes have been identified under topic 15, the ISO would incorporate those into the proposals for topics 1 and 2.

Lastly, this paper also addresses the remaining four topics within the scope of this initiative (i.e., topics 4, 5, 13, 14)[3]. At this time the ISO is not yet prepared to offer straw proposals for these four topics; nevertheless, this paper provides additional analysis of these topics based on stakeholder comments received and, for some, offers options for stakeholder consideration. The ISO does not expect to reach resolution on these topics until late 2013 or early 2014 and is targeting an early 2014 Board meeting for presentations of its final proposals on these four topics.

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.[4] For projects that entered the ISO queue prior to 2012 (i.e., up to and including Cluster 4), interconnection to the ISO grid is governed by the tariff provisions encompassed by the ISO's generator interconnection procedures ("GIP").[5] Successful 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,

[3] These four topics are (4) improve the Independent Study Process; (5) improve the Fast Track Process; (13) clarity regarding timing of transmission cost reimbursement; and, (14) distribution of forfeited funds.

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

[5] 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 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.

Generation Interconnection Procedures Phase 2 ("GIP 2") in 2011 and early 2012, and Generation Interconnection Procedures Phase 3 ("GIP 3") in 2012[6].

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.[7] 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 last year's GIP 3 stakeholder process a list of twenty-seven potential topics (including generator project downsizing) were compiled for consideration.
- Outside of the GIP stakeholder process, individual stakeholders have suggested GIP-related topics to the ISO over the past year.
- 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.
- An ISO internal need to improve the queue management process.

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

[6] 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.

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

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.[8]

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	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 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, the June 3 issue paper offered straw proposals for topics 6-12. Based on written stakeholder comments received on those proposals, the ISO developed a draft final proposal for topics 6-12 and posted that on July 2. This was followed with a stakeholder web conference on July 10 and written stakeholder comments on July 16. Based on this progress, the ISO anticipates presenting its final proposals for

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

IPE topics 6-12 to the ISO Board of Governors at its September 12-13 meeting. Details regarding the remaining stakeholder process for topics 6-12 are provided in the draft final proposal posted on July 2.[9] As a result, topics 6-12 will not be addressed in this paper.

The subject of this paper is the remaining eight topics of the IPE initiative. Straw proposals are offered on topics 1-3 and topic 15. The ISO is not yet prepared to offer straw proposals on topics 4, 5, 13, and 14 but will do so in subsequent papers. On topics 4 and 5 additional issue analysis is provided along with the working group schedule. For topics 13 and 14, issues and potential options are discussed.

Following presentation of the final proposals for topics 6-12 at the September Board meeting, the next targeted ISO Board of Governors meeting for presentation of final proposals on other IPE topics is the December 18-19 meeting. At this point in time, the ISO anticipates presenting final proposals for IPE topics 1-3 at the December meeting and presenting final proposals on all remaining topics (i.e., topics 4, 5, 13, 14) at an ISO Board meeting in early 2014. Implementation of the proposal for topic 15 involves adding clarifications to the BPM for GIP and similar language in the new BPM for the GIDAP and thus will not require Board approval; where needs for tariff changes have been identified under topic 15, the ISO would incorporate those into the proposals for topics 1 and 2.

3 Stakeholder process next steps

Table 2 summarizes the anticipated stakeholder process schedule for the remainder of the IPE initiative. Although the ISO's conventional naming jargon is used for the series of papers in this initiative, it's important to recognize that while each paper will likely contain proposals for some topics it may not on others. For example, the June 3 issue paper included straw proposals on topics 6-12 and the July 18 straw proposal is just that for topics 1-3 and topic 15 but does not include straw proposals for the remaining topics. Continuing with this logic, the September 12 draft final proposal will contain the draft final proposals for topics 1-3 but may contain straw proposals for topics 4, 5, 13, and 14.

Table 2 – Stakeholder process schedule

Step	Date	Milestone
Scoping proposal (all topics)	April 8	Post scoping proposal
	April 15	Stakeholder meeting (web conference)
	April 22	Stakeholder comments due

[9] http://www.caiso.com/Documents/DraftFinalProposal_Topics6-12_InterconnectionProcessEnhancements.pdf

Table 2 – Stakeholder process schedule

Step	Date	Milestone
Issue paper (all 15 topics)	June 3	Post issue paper
	June 11	Stakeholder meeting (web conference)
	June 25	Stakeholder comments due
Draft final proposal (Topics 6-12 only)	July 2	Post draft final proposal for topics 6-12
	July 10	Stakeholder web conference (Topics 6-12)
	July 19	Stakeholder comments due (Topics 6-12)
	Sept 12-13	ISO Board meeting (Topics 6-12)
Straw proposal (Topics 1-5 & 13-15)	July 18	Post straw proposal
	August 8	Stakeholder meeting (in person)
	August 22	Stakeholder comments due
Draft final proposal (Topics 1-5 & 13-15)	September 12	Post draft final proposal
	September 19	Stakeholder meeting (web conference)
	October 3	Stakeholder comments due
Present proposals on Topics 1-3 to Board	December 18-19	Board of Governors meeting (Topics 1-3)
Additional papers as needed for remaining topics (e.g., Topics 4, 5, 13, 14)	Q4 2013 / Q1 2014	Posting additional papers as needed for remaining topics, holding stakeholder web meetings, and soliciting written stakeholder comments
Present proposals on remaining topics to Board (e.g., Topics 4, 5, 13, 14)	Q1/Q2 2014	Board of Governors meeting (Topics 4, 5, 13, 14)

4 Topics

This section discusses the issues associated with Topics 1-5 and 13-15, summarizes stakeholder comments received in response to discussion of these topics in the June 3 Issue Paper, and for some of the topics, offers a 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.

Several stakeholders have pointed out that topics 1-3 are closely related with the the potential for providing additional flexibility to generator project developers in sizing and structuring their projects. Some stakeholders suggested that all three topics be combined into a single topic. The ISO decided to keep the three topics separate for purposes of developing proposals, in view of the fact that each topic contains multiple sub-issues that must be addressed individually anyway. This approach has not, however, prevented the ISO from properly considering the interrelationships among these topics and their sub-issues.

4.1 Topic 1 – Future downsizing policy

When the one-time generator project downsizing proposal was brought before the ISO Board on September 13, 2012, the Board directed ISO management to consider whether it was appropriate to provide a future, second downsizing opportunity following the ISO's completion of the interconnection studies for Cluster 5.[10] Pursuant to the Board's direction, the ISO has been considering a second downsizing opportunity for pre-Cluster 5 projects in this initiative. However, the narrow question of whether a second downsizing window should be provided is more properly addressed within the broader context of what should be the ISO's ongoing downsizing policy for pre-Cluster 5 projects should be more generally. Thus, the purpose of this topic has been to answer this broader question, and to do this in consultation with stakeholders and with the objective of presenting a final proposal to the ISO Board at its December meeting.

Generator project downsizing has been a topic of significant interest to generation developers in recent years. The state's renewable policy goals have resulted in significant development of new renewable solar and wind projects. The design of these projects is often scalable, and, as a result, the developer may, for a number of reasons, find it desirable or necessary to reduce the size of the project from what was originally proposed in their interconnection request. The reasons often cited for their need to downsize include the inability to secure a power purchase agreement for the full amount of the project, specific terms in their power purchase agreements, or reasons that may be beyond the control of interconnection customers such as the inability to obtain permitting and governmental approvals for the full capacity that was studied. In any case, interconnection customers have indicated that they may find themselves in a situation where the project size in their original interconnection request may be too large, thereby impeding their ability to comply with the requirements of their interconnection agreement.

While interconnection customers in the ISO interconnection queue already have existing opportunities to downsize, they have continued to express an interest in an additional mechanism to downsize their project. This interest resulted in development of the one-time downsizing opportunity approved by FERC in late 2012 and which is currently being implemented by the ISO (see discussion of this implementation in Section 4.1.2).

[10] As of this writing, the interconnection study process for Cluster 5 is not complete. The Phase I interconnection studies have been completed, but the Phase II studies are in progress and the study reports will be issued in December 2013.

4.1.1 *Existing options for reducing project size*

This section clarifies the existing options to reduce project size available to customers prior to the one-time downsizing opportunity approved by FERC in 2012. These pre-existing opportunities continue to be available today.

Changes during interconnection studies when all parties agree. Both ISO tariff Appendix U and Appendix Y provide that, at any time during the course of the interconnection studies, the interconnection customer, the applicable PTO, or the ISO may identify changes to the interconnection "that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request." If such changes are acceptable (with consent to such changes not to be unreasonably withheld), then the ISO modifies the interconnection configuration, in accordance with the agreed-upon changes.[11] Appendix Y also provides that during the period between the issuance of the Phase I study and five days after a customer's Phase I results meeting, a customer may submit certain types of modifications to its project, including a reduction in capacity.[12]

Material modification review. An interconnection customer may also seek to downsize its project after the study process has concluded pursuant to the terms of the customer's generator interconnection agreement. The generator interconnection agreements under the ISO tariff for both serial and cluster projects provide that an interconnection customer may undertake modifications to its facilities. Such modifications are subject to a material modification review in accordance with the relevant interconnection procedures and agreements.[13] The ISO, in coordination with the affected participating transmission owner(s), performs a material modification review for an interconnection customer's request. However, such modification requests are subject to a material modification review on a project-by-project basis in order to determine whether granting the requested modification would have a material impact on the cost or timing of later-queued interconnection requests. If the requested modification would not have such an impact, then the ISO will grant the request. If there is a material impact, or if a study would be required to determine if there is a material impact, then the modification request must be denied, and in such instances there are no provisions whereby which the interconnection customer can mitigate the material impact. Given the number of interconnection customers and the interdependencies of the projects in the ISO queue, it is highly unlikely that many projects requesting to downsize this way would be able to pass the material modification review. For projects seeking other types of changes other than reducing the size of their project, the ISO has approved many material modification review requests. The ISO has not and will not expand the

[11] Appendix U Section 4.4; Appendix Y Section 6.9.2.1; Appendix DD 6.7.2.
[12] Appendix Y, Section 6.9.2.2.
[13] Appendix T Article 6.2; Appendix U Articles 4.4.3, 4.4.5; Appendix Z Article 5.19.1; Appendix BB Article 5.19.1; Appendix CC Article 5.19.1; Appendix EE Article 5.19.1; Appendix FF Article 6.2.

material modification review process to evaluate downsizing requests. For the same reasons the ISO moved to a cluster study process for generator interconnection requests and away from the serial study process, studies of individual downsizing requests is impracticable. The ISO must be able to study downsizing MWs collectively and be able to incorporate the study results in the next cluster study. . Therefore, as explained below, the ISO is proposing to clarify that this option will not be available, going-forward, as a means to obtain project downsizing.

<u>Safe-harbor and substantial performance provisions.</u> A third option available to customers involves the "safe-harbor" provision. The *pro forma* large generator interconnection agreement, in effect as of January 31, 2012, contains a "safe-harbor" provision under which an interconnection customer may reduce the MW capacity of its generating facility by up to five percent for any reason, up until its commercial operation date, and may request authorization from the ISO to reduce the MW capacity of its generating facility by more than five percent under limited conditions where the interconnection customer reasonably demonstrates that the more-than-five-percent reduction is warranted due to any of three specified reasons beyond the control of the interconnection customer:

1. Failure to secure required permits and other governmental approvals to construct the generating facility at its total MW generating capacity specified in the interconnection request after making diligent efforts.
2. Written statement from the permitting or approval authority indicating that construction of the facility at the total MW size specified in interconnection request will likely result in disapproval due to significant environmental or other impact that cannot be mitigated.
3. Failure to obtain legal right to use the full site acreage necessary to construct/operate the total MW generating capacity size for the entire generating facility after making diligent efforts (only applies where an interconnection customer previously demonstrated and maintained its demonstration of site exclusivity for the full acreage required for the project).

<u>Use of non-conforming "partial termination" provision.</u> A fourth option available to customers is use of non-conforming "partial termination" provision. The ISO has filed and obtained FERC acceptance of four non-conforming generator interconnection agreements that include partial termination provisions allowing customers that are building generating facilities with multiple phases to invoke partial termination of their generator interconnection agreements with regard to later phases without breaching the generator interconnection agreements and without adverse impacts on the earlier phases. The partial termination provisions were developed in 2010 to address the unique circumstances of these interconnection customers. In each case, the construction of the final segments of the network upgrades for their phased generating facilities required at least three years past the requested in-service date and in some instances an extremely long lead time – 84 months – resulting in significant commercial uncertainty as to whether the

developer could find a counterparty for the generating capacity that could not be interconnected or would not be deliverable until the upgrades were built. The ISO continues to consider partial termination provision for cluster and serial projects that are similarly situated to the projects that were subject to the four earlier non-conforming agreements approved by FERC. Specifically, the ISO will consider the inclusion of partial termination provisions in the interconnection agreement of a cluster or serial project meeting the following criteria:

1. Total project size is at least 50 MW;
2. Project will be developed in phases;
3. The PTO will require three or more years, from the customer's requested in-service date of the first phase, to build the required transmission;
4. There is no material impact to later queued customers;
5. The customer agrees to post security for, and pay if partial termination is exercised, a partial termination charge, the amount of which is determined by the ISO to be proportional to the risk of stranded transmission infrastructure investment if the customer exercises the partial termination by cancelling a later phase of the project.

The ISO does not view use of the partial termination provision as a generally applicable downsizing option. It was developed to address extreme uncertainty for later phased projects dependent upon transmission upgrades with planned in-service dates significantly in the future. Although the ISO is willing to offer this option to similarly situated interconnection customers, the ISO does not support expansion of this limited option. Instead, the ISO is proposing an annual downsizing opportunity in this straw proposal to provide additional flexibility to generation developers.

<u>Reducing project size under GIDAP.</u> Lastly, for customers in Cluster 5 and later, several new provisions in the ISO's generator interconnection and deliverability allocation procedures (GIDAP) tariff amendment allow them to reduce the MW generating capacity of their proposed facility.[14] If a project is allocated TP Deliverability in an amount less than the amount requested, then the customer much choose amongst several options. The options relevant to reducing the MW generating capacity are discussed here. One option is for the customer to accept the allocated amount and reduce the MW capacity of the project such that the allocated amount of TP Deliverability will provide full capacity deliverability status (FCDS) to the reduced generating capacity. Under another option for Option (A) projects, the customer would accept the allocated amount of TP Deliverability and seek additional TP Deliverability for the remainder in the next allocation cycle. Based on the final amount of TP Deliverability allocated following the next allocation cycle the project could accept the final amount and reduce the MW generating capacity such that the allocated amount will provide FCDS to the reduced generating capacity.

[14] Appendix DD Section 8.9.5.

4.1.2 *One-time downsizing opportunity*

This section describes the one-time downsizing opportunity approved by FERC in 2012.

Generator project downsizing was a topic suggested by stakeholders in GIP 3 and received the highest priority in the March 2012 stakeholder survey in that initiative. In response to this stakeholder demand, in 2012 the ISO deferred work on the other topics in GIP 3 and instead focused its efforts on a separate stakeholder initiative to explore the possible expansion of opportunities for generator interconnection customers prior to Cluster 5 (see feature number 2 discussion below) to downsize the MW capacity of their proposed generating facilities. The ISO worked with stakeholders over the course of 2012 and developed a one-time opportunity for all customers in the ISO's interconnection queue that entered the queue prior to Cluster 5 to downsize their projects. Tariff amendments to implement this one-time downsizing opportunity were filed with FERC on October 26, 2012. The FERC approved the ISO's proposal on December 20, 2012. The FERC found that the one-time downsizing opportunity:

- provides a balanced approach to eliminate non-viable requests from the ISO's interconnection queue, while protecting non-downsizing customers from harm;
- is responsive to requests from affected interconnection customers for an opportunity to downsize their projects in addition to the ISO's existing downsizing options;
- will help facilitate completion and commercial operation of projects that would be viable but for an inability to construct the full generating capacity stated in the customers' interconnection requests;
- will help ensure that more projects can achieve commercial operation, even though at a smaller scale than originally planned; and,
- will help spur energy development and advance ISO's efforts to reduce non-viable interconnection requests from its queue.

The FERC also found:

- the cost cap on downsizing generators' study deposits to be reasonable; and,
- that downsizing generators should bear the costs of their downsizing on all impacted generators, regardless of whether the impacted generator is connected to the ISO-controlled grid or to the distribution system of one of the PTOs.

The ISO's one-time downsizing opportunity had the following important features:

1. <u>One-time opportunity.</u> The new downsizing opportunity was only offered as a one-time option. It established a one-time window for developers to submit a downsizing request to permit transmission planning engineers to evaluate the collective impacts of all requests.

2. Limited to pre-Cluster 5 customers. This was done for several reasons. First, at the time of the ISO's filing, customers in Cluster 5 had not yet received their Phase I interconnection study reports, and so still had the opportunity to downsize before entering Phase II. Second, customers in Cluster 5 would possibly have the opportunity to downsize again after receiving results of the transmission plan deliverability allocation pursuant to GIDAP.[15] Even after these downsizing opportunities, Cluster 5 customers will be able to avail themselves of the "safe harbor" provisions described earlier. Finally, it was premature to consider substantive changes to the GIDAP rules, which had just been approved by FERC and were in the early stage of their first implementation.
3. Obligation of downsizing generators for costs to process the requests. A $200,000 downsizing deposit was required to help defray costs incurred by the ISO and the participating transmission owners to process the requests. This deposit was applied as a pool of funds to pay for prudent costs incurred by the ISO, the PTOs, or third parties at the direction of the ISO or PTOS, as applicable, to perform and administer the generator downsizing process and to communicate with downsizing generators with respect to their generator downsizing requests. These include (1) costs associated with the generator downsizing study and associated reports and (2) costs associated with amending the generator interconnection agreements of downsizing generators and any generators affected by the downsizing requests. If the amount required to pay for those costs was determined to be more than $200,000, then the downsizing generator would be obligated to provide the additional amount, subject to the cost caps.[16] Conversely, if the amount required to pay for those costs was determined to be less than $200,000, then the downsizing generator would be refunded the unused balance of its deposit, with interest.
4. Downsizing study utilized to assess impacts of downsizing requests. The ISO conducted a special downsizing study to determine the impacts of the downsizing requests on the current customer interconnection plans of service developed through their earlier interconnection studies. The study process was substantially the same as the ISO's existing

[15] The ISO's generation interconnection and deliverability allocation procedures (GIDAP) tariff amendment, which was approved by FERC on July 24, 2012, includes several new provisions to allow customers in Cluster 5 and beyond to downsize their projects. These were briefly described previously in section 4.1.1 of this paper.

[16] Each downsizing generator was responsible for an equal share of all actual costs of the generator downsizing study and the generator downsizing study report. The downsizing generator's share was determined by dividing the total amount of actual study costs by the number of valid generator downsizing requests, with that resulting amount being capped at an amount no higher than 150 percent of the downsizing generator's equal share of the preliminary cost estimate. The preliminary cost estimate was determined to be $103,231 per downsizing project; thus, the cap was $154,846 per downsizing generator. Each downsizing generator's responsibility for the costs to amend generator interconnection agreements was $10,000 for its own such agreement and $10,000 for each such agreement of an affected generator that is amended, in whole or in part, due to the downsizing generator's generator downsizing request, subject to a cost cap of $100,000.

cluster study process. The costs of the downsizing study, and any resulting interconnection agreement amendments, were borne by customers requesting downsizing.

5. Withdrawal opportunities provided. Downsizing generators were given two "off-ramp" opportunities to withdraw from the downsizing effort. First, each downsizing generator had an opportunity to withdraw its generator downsizing request after being given a preliminary estimate of its obligation for downsizing study costs. There was a second opportunity to withdraw for each downsizing generator notified by the ISO that the generator's preliminary study results show that its estimated responsibility for network upgrade costs may significantly increase. None of the downsizing generators exercised the first and none met the rules to withdraw under the second.
6. Original cost allocations determined the cost assignment for refreshed configurations. If the downsizing required the upgrades to be modified or substituted, the resulting costs would be assigned in proportion to downsizing customers' responsibility for the costs of the original upgrades, thus preserving the original allocation of costs among interconnection customers in the queue.
7. Protection for customers who are affected but not downsizing. So that non-downsizing interconnection customers are left no worse off with regard to upgrade costs as a result of the decision of other customers to utilize this one-time opportunity to downsize, downsizing-related cost increases or cost shifts to non-downsizing customers were the responsibility of the downsizing customers.
8. Obligation to meet milestones. Each downsizing generator was required to relinquish its suspension rights in return for its opportunity to downsize.

In January 2013 the ISO began implementation of the one-time downsizing opportunity approved by FERC the previous month. Thirteen valid downsizing requests were received representing a downsizing reduction of nearly 4,000 MW. The ISO posted a list of the valid downsizing requests identified by queue position along with a preliminary estimate of study cost in February.[17] None of these projects exercised the first opportunity to withdraw their generator downsizing request

[17] The ISO, in consultation with the PTOs, developed a preliminary estimate of the cost to perform the downsizing study for the thirteen valid downsizing requests. This study cost was estimated to be $1,342,000 or $103,231 per downsizing project. In accordance with ISO Tariff Appendix GG, a downsizing generator is responsible for all actual costs incurred in connection with preparing the generator downsizing study and the generator downsizing study reports. A downsizing generator's share of actual study costs is determined by dividing the total amount of actual study costs by the number of valid generator downsizing requests, but is no higher than an amount equal to 150 percent of the downsizing generator's share of the preliminary estimate posted. If the generator downsizing deposit ($200,000) is insufficient to cover the costs for which the downsizing generator is responsible, the ISO will invoice the downsizing generator and such amount will be paid within thirty (30) calendar days of the date of the invoice.

under the rules of the one-time downsizing opportunity after being given the preliminary estimate of its obligation for downsizing study costs. None of these downsizing generators had a second opportunity to withdraw under the one-time downsizing rules.[18]

The generator downsizing study for the one-time downsizing study has now been completed and study reports were sent to the downsizing projects, as well as projects affected by the downsizing process, in early July 2013. A total of twelve projects remain in the downsizing process[19] and an additional 17 projects were impacted by the decrease in generating capacity. The final reduction in project capacity requested by the twelve projects totals 3,698 MW.

Appendix A provides a detailed summary of the steps and timeframes associated with this one-time generator downsizing process.

4.1.3 *Stakeholder comments*

Following publication of the June 3 issue paper, the ISO solicited stakeholder feedback on the topic of future downsizing policy by posing a number of questions in the June 11, 2013, stakeholder comments template. Using a question and answer format, these stakeholder comments are summarized below.

Question 1: Stakeholders were asked what demand there is for a second downsizing opportunity. Stakeholders were asked whether a second downsizing opportunity would be sufficient, or whether there will be further demand beyond a second downsizing opportunity.

Independent Energy Producers (IEP) – Supports a second downsizing opportunity. Also believes that there are benefits to additional downsizing windows for pre-Cluster 5 projects.

Large-scale Solar Association (LSA) – Believes a second downsizing opportunity should be provided, at a minimum, for Cluster 3-4 projects and those with CODs after 2016. Ideally this second opportunity should occur around the end of 2014. Supports annual downsizing opportunities open to all projects in coordination with the GIDAP Phase II pre-validation/reassessment studies. Downsizing should be subject to the "hold harmless" provisions of the one-time downsizing opportunity. Loss of project suspension rights should not be required for projects exercising this option.

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[18] In April, the ISO notified the downsizing generators that it had completed the preliminary analysis for the generator downsizing study and determined that no project participating in the downsizing study would have their cost responsibility increase; therefore, no downsizing project will had a second opportunity to withdraw. Per the CAISO Tariff, Appendix GG Section 5.1 (ii), the Downsizing Generator would have a second opportunity to withdraw when the preliminary results of the Generator Downsizing Study indicated that the Downsizing Generator's cost responsibility for Network Upgrades increased by more than five percent (5%) or five million dollars ($5,000,000), whichever was lower, from its cost responsibility identified in its Interconnection Facilities Study or Phase II Interconnection Study report.

[19] One downsizing project withdrew its Interconnection Request prior to the deadline for the second interconnection financial security ("IFS") posting. In accordance with the rules of the one-time downsizing opportunity, the project forfeited its downsizing deposit which helped defray the downsizing costs of the remaining twelve projects.

NRG Energy (NRG) – Would like to see at least a second downsizing opportunity for all customers prior to Cluster 5. Supports regular ongoing downsizing opportunities, subject to restrictions such as a limited request window.

Silver Ridge Power – A second downsizing opportunity should be provided, at a minimum, for projects with a COD after 2016. Ideally this second opportunity would come around the end of 2014. Supports annual downsizing opportunities open to all projects in coordination with the GIDAP Phase II pre-validation/reassessment studies. Additional downsizing opportunities will help clear out the queue. Downsizing should be subject to the "hold harmless" provisions of the one-time downsizing opportunity. Loss of project suspension rights should not be required for projects exercising this option.

Southern California Edison (SCE) – Does not see a benefit in providing unlimited downsizing opportunities to the same set of pre-Cluster 5 projects each year. Believes that there should be limits on the number of downsizing requests that a generating facility can submit, perhaps limiting to one or two such requests during the lifecycle of a project.

SunEdison – Strongly supports an annual downsizing opportunity without unnecessary prerequisites. Such downsizing should be allowed to the extent that later-queued projects are not adversely impacted.

Wellhead – Until the queue is cleared of all pre-Cluster 5 projects, there will likely remain a desire for downsizing opportunities. The ISO should require a project that receives the benefits of downsizing to agree to the GIDAP requirements related to how long it can remain in the queue and for receiving deliverability.

California Wind Energy Association (CalWEA) – Supports a downsizing option that would allow projects to continuously reduce their size based on well-established eligibility criteria and reasonable evaluation protocols including financial consequences.

<u>Question 2:</u> Stakeholders were asked their view on the ISO's position that a downsizing request window of limited time duration should be utilized in any future downsizing opportunity.

IEP – Supports using a time window to limit the period within which interconnection customers may submit a downsizing request.

LSA – Supports downsizing opportunities offered in coordination with regular study processes.

NRG – Does not object to downsizing windows of limited duration if regular downsizing opportunities are provided.

Pacific Gas and Electric (PG&E) – Agrees with ISO, and strongly recommends consolidating any future downsizing windows with the existing annual queue cluster windows.

SCE – Downsizing request windows should coincide with annual queue cluster interconnection request submission window.

Silver Ridge Power – Downsizing opportunities should be offered in the regular study process as this would allow consideration of the "collective impact" of all downsizing requests.

Six Cities[20] - Agrees with ISO that any future downsizing opportunities should be submitted during a request window of a limited time duration to assess the collective impacts of all downsizing requests at the same time. Agrees with the ISO that such request windows should coincide with existing study cycles.

Wellhead – If more downsizing opportunities are to be provided to pre-Cluster 5 projects, it is entirely rational/reasonable for it to be done in "groups".

CalWEA – Setting frequency/timing limitations on downsizing requests will reduce the usefulness of a downsizing policy.

Question 3: The ISO explained its belief that funneling downsizing requests through such a window permits ISO and PTO transmission planning engineers to evaluate the collective impacts of all downsizing requests in the most efficient manner possible (in contrast to the inefficiency and associated chaos of having to review the impacts of downsizing requests sequentially, at any time that an interconnection customer chooses to submit such a request). Similarly, expansion of the ability to downsize through a "material modification" review would essentially allow downsizing requests to be submitted at any time and would thus present the same problems. Stakeholders were asked their view on this.

California Public Utilities Commission (CPUC) – Believes that future downsizing opportunities should be limited to one per year or every other year, and timed to synchronize with the ongoing interconnection process study cycle.

IEP – Understands the concern about the frequency and unpredictable nature of downsizing requests that could conceivably arise from an expansion of material modification rules. Recommends an annual downsizing opportunity.

LSA – The ISO should allow downsizing without any study required where the customer agrees to pay for its allocated share of transmission costs for the original project. Otherwise, supports incorporating downsizing studies with the GIDAP Phase II pre-validation/reassessment studies.

NRG – Understands the reasons for considering downsizing requests in a "cluster" and does not object to this approach.

PG&E – Agrees with the ISO position. However, PG&E would be open to very narrow use of out-of-cycle downsizing requests provided it met certain conditions: (a) no changes are made to scope of

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[20] Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.

work for any network upgrades in the downsizing generator's GIA; (b) the GIA's Exhibit A is in no otherwise way changed; (c) no restudy required; (d) in order to hold harmless ratepayers, the downsizing generator agrees to forgo reimbursement for a pro-rata share of network upgrades (e.g., if a project is downsized by 25 percent then the customer can only seek reimbursement for 75 percent of network upgrades); and, (e) other generators, ratepayers, and PTOs are not financially or otherwise affected.

Silver Ridge – The ISO should allow downsizing without any study required where the customer agrees to pay for its allocated share of transmission costs for the original project. Otherwise, supports incorporating downsizing studies with the GIDAP Phase II pre-validation/reassessment studies.

SCE – Any possible future downsizing opportunity should be open for a limited and defined duration only and should be scheduled concurrently with the queue cluster interconnection window. A limit to the number of downsizing requests should be implemented.

Wellhead – Projects eligible for any additional proposed downsizing opportunities would seemingly have no need to use a material modification request to downsize. The ISO should not eliminate the material modification request, but have higher hurdles for a project to demonstrate why it cannot wait for the next group downsizing opportunity.

CalWEA – Believes that any generator that needs to reduce its size should be allowed to make a downsizing request at the time when the need for such downsizing arises and there should be no request window. Believes that the ISO should study downsizing requests individually as soon as they are received unless it is determined that a cluster study is required. Suggests that a cluster study should be used if the individual studies of three or more downsizing requests that have a common impact on one or more reliability or delivery network upgrades in an approved GIA would overlap in time. In such a case, the study of these downsizing requests would be combined with the next annual cluster study process.

<u>Question 4:</u> Stakeholders were asked that to the extent there was a need for additional downsizing opportunities, what would be the optimal frequency of downsizing request windows? For example, should there be one per year or one every two years? How many downsizing request windows do stakeholders believe should be considered? What should be the timing of a downsizing request window? The ISO suggests that the timing of a downsizing request window should be such that there is sufficient time to validate the requests received and study their combined impacts at the same time the re-assessment study is conducted in accordance with the GIDAP timeline. Stakeholders were asked their view on that.

IEP – Recommends an annual downsizing process consistent with the timing of the ISO's cluster study schedule. Does not believe it necessary to set any limits on the number of downsizing request windows (the number of future downsizing request windows needed is likely to be self-limiting).

LSA – Believes that annual consideration of downsizing requests should take place in the GIDAP pre-validation/reassessment process.

NRG – There should only be one downsizing window per year. Supports regular windows for some period of time (if and when the number of downsizing requests cease, the continued need for regular request windows can be re-examined). Supports the ISO's suggested timing for downsizing request windows.

PG&E – Believes downsizing windows should occur at a maximum annually; less frequently would be preferred. If limited to pre-Cluster 5, then the process should have a defined end date where no additional downsizing request windows would be provided (perhaps 2016 to correlate to a timeframe when most legitimate pre-Cluster 5 projects should have advanced towards commercial operation). Agrees with the ISO's position on the timing of a downsizing request window; moreover, urges that downsizing results are released in conjunction with GIDAP study results.

Silver Ridge Power – Annual consideration of downsizing requests should take place in the GIDAP pre-validation/reassessment process.

Six Cities – The timing of a downsizing request window should allow for adequate time to validate and study the requests in conjunction with the study timelines provided for under the GIDAP.

SCE – The frequency should not be greater than one per year, and the timing of a downsizing request window should coincide with annual queue cluster interconnection request window and should not interfere with the timelines of the annual transmission planning process.

Wellhead – An annual downsizing opportunity at most seems sufficient. Coordinating any downsizing opportunities with existing study efforts is definitely reasonable. Questions whether a project should be able to downsize more than once.

CalWEA – There should be no limit on the frequency of downsizing requests.

<u>Question 5:</u> Stakeholders were asked to comment on the ISO's position that future downsizing options should be limited to pre-Cluster 5 customers because the GIDAP already provides certain opportunities to downsize projects that were not available under the GIP.

CPUC – Believes that until we have full experience and assessment regarding the GIDAP process, downsizing options should not be offered to Cluster 5 and later interconnection customers. When we do have that experience and assessment, extending additional downsizing opportunities to Cluster 5 and later customers could be considered if needed.

IEP – Considers the GIDAP provision for reducing project generating capacity in the event that a project's deliverability allocation is less than the project's full size a valuable tool to protect commercial interests of generators. Suggests that annual project downsizing windows may be beneficial in Cluster 5 and later and should be carried forward by the ISO for future review, however, the issue is not ripe for consideration in the IPE initiative given GIDAP's immature status.

LSA – Believes that there is insufficient information available at this early point in the implementation of GIDAP to determine whether that process requires additional downsizing flexibility beyond that already available. If the ISO limits its proposal for additional downsizing opportunities to pre-Cluster 5, then that element of the proposal should be re-evaluated after the first GIDAP study cycle is complete.

NRG – Especially interested in ensuring downsizing opportunities for pre-Cluster 5 projects and does not object to the ISO's position on this issue.

SCE – Agrees that any future downsizing options should be limited to pre-Cluster 5 customers. Not only does GIDAP provide certain opportunities to downsize projects that did not exist for pre-Cluster 5 customers but the GIDAP is undergoing initial implementation and it would be difficult to gauge its effectiveness in accomplishing its intended objectives if new concepts or issues are superimposed prior to the benefit of having completed at least one cycle of GIDAP implementation.

Wellhead – Depending on how future downsizing opportunities are implemented, there will be significantly more flexibility than is available to Cluster 5 and later projects (there's no reason to discriminate against Cluster 5 and later projects).

CalWEA – Even with the additional opportunities that projects will have under GIDAP to downsize, there will always be a need for additional opportunities to reduce project size.

<u>Question 6:</u> Stakeholders were asked to comment on other important features of the one-time downsizing opportunity. For example, customers who are affected by but are not downsizing should be protected. As an additional example, downsizing projects should bear the costs of the downsizing study and any resulting interconnection agreement amendments.

CPUC – Downsizing customers should bear all of the costs and non-downsizing customers should not be negatively impacted. Downsizing customers should be permanently (without refund) responsible for transmission costs that were originally the responsibility of that customer prior to downsizing if those costs cannot be avoided.

IEP – Believes that the interconnection customer requesting downsizing should bear the cost responsibility for that request and that a non-downsizing customer should be held harmless with respect to the costs created by the study and costs due to modification of network facilities and, as much as possible, timing of network upgrades.

LSA – Supports the "hold harmless" protection for non-downsizing customers but opposes charges for ISO/PTO costs to amend the agreements for such customers. Annual GIDAP pre-validation/reassessment studies are likely to result in multiple GIA amendments and it will be difficult if not impossible to separate out the amendments due to downsizing from the amendments due to other causes.

PG&E – Affected non-downsizing customers should be protected. Ratepayers must be protected against having to fund upgrades that are underutilized due to downsizing. PTOs must be protected against having to self-fund upgrades that are only partially funded by customers due to a downsizing.

Silver Ridge Power – Supports the "hold harmless" protection for non-downsizing customers but opposes charges for ISO/PTO costs to amend the agreements for such customers. Annual GIDAP pre-validation/reassessment studies are likely to result in multiple GIA amendments and it will be difficult if not impossible to separate out the amendments due to downsizing from the amendments due to other causes.

Six Cities – Customers that are availing themselves of downsizing opportunities should bear all costs associated with their downsized projects.

SCE – Any future downsizing opportunity should be structured to minimize, if not fully mitigate, any adverse impacts on other ICs as well as the PTOs. Downsizing customers should bear the costs of downsizing studies and amending GIAs. ISO needs to close a loophole of the one-time downsizing opportunity: that is, customers should not be allowed to downsize to some *de minimus* amount (such as 0.5 MW) to avoid or lower its interconnection financial security postings.

Wellhead – As a minimum, downsizing projects should be required to accept the deliverability allocation and time in the queue provisions applicable under GIDAP.

CalWEA – Does not object to requiring downsizing generators to bear the cost of their downsizing studies and any resulting GIA amendments, or to bear the costs of compensating affected customers.

<u>Question 8:</u> Stakeholders were asked about their view on the continued use of the non-conforming partial termination provisions as a future downsizing option. Although the ISO does not view this as a generally applicable downsizing option, stakeholders were asked if they viewed its continued availability as critical.

CPUC – Under any kind of future partial termination provisions, the cost of any transmission upgrade initially the responsibility of the "partially terminated" project should be borne, both initially and ultimately, by the project developer, to the extent that this cost cannot be avoided.

IEP – Believes the non-conforming partial termination provisions should continue in the event that the non-typical situations for which that provision was intended arise in the future for an interconnecting customer.

LSA – Believes that this option should continue to be available for those meeting the specified conditions that desire advance cost certainty. In addition, the ISO should re-visit the GIP 2 proposal to make this option more widely available.

PG&E – Believes all downsizing, including partial termination, should occur through the same process. If partial terminations were to be requested, they should either have to apply during the study window or meet the criteria for an out-of-cycle request (suggested by PG&E above).

Silver Ridge Power – Believes that this option should continue to be available for those meeting the specified conditions that desire advance cost certainty. In addition, the ISO should re-visit the GIP 2 proposal to make this option more widely available.

Six Cities – Do not oppose its continued use as long as ratepayers are held harmless from stranded investment costs as a result of partial termination. To the extent that other downsizing opportunities are available, the ISO's continued use of partial termination provisions only on a limited, case-by-case basis appears to be reasonable.

SCE – Agrees that the non-conforming partial termination provisions should generally not be considered as a future downsizing option.

SunEdison - Believes that this option should continue to be available for those meeting the specified conditions that desire advance cost certainty. In addition, the ISO should re-visit the GIP 2 proposal to make this option more widely available.

Wellhead – The procedures currently allow for partial termination for certain events and this should not be eliminated.

CalWEA – Finds these partial termination provisions to be very excessive and that, instead, the material modification mitigation criteria should be used to address the consequences of generator downsizing requests. Believes that a downsizing project should be obligated to finance the network upgrades that the project at its full size triggered if later-queued projects are shown to need such upgrades. Further believes that the network upgrade refund to the project should be limited to only the completed portion of the project (perhaps using a pro-rata algorithm to determine the level of refund).

4.1.4 *Straw proposal*

Based on a review of the stakeholder comments received, it is clear that there continues to be demand for additional generator downsizing opportunities. The ISO appreciates the many constructive views and opinions expressed by stakeholders regarding the potential features of future downsizing opportunities. Based on this stakeholder feedback, the ISO proposes that additional downsizing opportunities be provided. The elements of the ISO's proposal are as follows:

- Annual downsizing opportunity. The ISO proposes that there be one downsizing opportunity each year. The ISO does not propose to limit the number of annual downsizing opportunities but allow them to continue until there is no further demand.
- Eligibility to submit a downsizing request. The ISO proposes that the annual downsizing opportunity will be open to any active[21] project in Cluster 4 or earlier that wants to downsize for any reason.
- Downsizing request window. The ISO proposes that there be a one month "request window" for submitting downsizing requests. The downsizing request window will open in mid-October of each year and all downsizing requests must be received by mid-November in order to be studied in the subsequent annual GIDAP reassessment process.[22] The first submission deadline will be mid-November 2014.
- Downsizing study. The ISO proposes to study the combined impacts of the valid downsizing requests in the annual GIDAP reassessment process. Downsizing requests received by mid-November will be validated by the ISO by mid-December. A validation process equivalent to that in existing tariff Appendix GG will be used. Knowing the set of valid downsizing requests by mid-December will make it possible to incorporate this information into the annual GIDAP reassessment process which begins in January of each year.
- Number of downsizing requests. The ISO does not propose to limit the number of annual downsizing requests that a generating facility can submit. However, the limit on the number of years a project can remain in the interconnection queue will remain in effect (10 years in the queue from the interconnection request date to the in-service for serial projects and 7 years in the queue from the interconnection request date to the commercial operation date for cluster projects).
- Size of downsizing request. The ISO does not propose a limit on the MW amount of downsizing permitted. The one-time downsizing process imposed no such limit and the ISO received some downsizing requests representing a substantial decrease in project capacity (e.g., in the case of one downsizing request, a 400 MW project downsized to 0.5 MW). Although some stakeholders view this as a means to avoid or lower interconnection financial security postings, the ISO suggests that this should be balanced against the

[21] For purposes of this proposal, the term "active" is used to refer to projects that satisfy the following requirements: (i) the interconnection request has not been previously withdrawn or deemed withdrawn by the ISO; (2) the customer is in compliance with all applicable ISO tariff requirements; and, (3) the customer is in compliance with the terms of the generator interconnection agreement, meaning that any notice of breach or default has been cured.

[22] Under Appendix DD Section 7.4 (GIDAP), the ISO will perform a reassessment of the Phase I Interconnection Study base case prior to the beginning of the GIDAP Phase II Interconnection Studies. For example, this reassessment will include information concerning Interconnection Request withdrawals that occurred after the completion of the Phase II Interconnection Studies for the immediately preceding Queue Cluster. Under this straw proposal, the ISO is proposing to also include information concerning the downsizing requests received by mid-November. The reassessment is used to develop the base case for the Phase II Interconnection Study.

benefits this may provide relative to the ISO's efforts to reduce non-viable interconnection requests from its queue.

- Protection for customers who are affected but not downsizing. Downsizing customers are obligated to finance the network upgrades that the project at its full size triggered if later-queued projects are shown to need such upgrades.
- Generator downsizing deposit. The ISO believes that all downsizing customers should bear the costs of downsizing studies and amending their GIA. To accomplish this, the ISO proposes that downsizing generators be required to provide a generator downsizing deposit to be applied as a pool of funds to pay for prudent costs incurred by the ISO, the participating transmission owners, or third parties at the direction of the ISO or participating transmission owner(s), as applicable, to perform and administer the generator downsizing process. These include (1) costs associated with the generator downsizing study and production of the downsizing generator's study report and (2) costs associated with amending the generator interconnection agreement of the downsizing generator. Thus the generator downsizing deposit will consist of two parts. With regard to study costs associated with each downsizing request, the ISO proposes that the generator downsizing study portion of the generator downsizing deposit be equal to $50,000.[23] The downsizing generator's share of the actual study costs will be equal to the actual costs of that particular annual GIDAP reassessment multiplied by a ratio with the quantity of one in the numerator and the sum of three quantities in the denominator. The three quantities in the denominator would be (i) the number of new downsizing requests; (ii) the number of Interconnection Request withdrawals since the last GIDAP reassessment; and, (iii) the number of projects that have reduced the MW generating capacity or changed deliverability status of their proposed facility under the GIDAP rules. Quantities (ii) and (iii) are the drivers that the GIDAP reassessment was originally designed to account for. With regard to the costs associated with amending the GIA of the downsizing generator, the ISO proposes that the downsizing generator's responsibility for the costs to amend its own generator interconnection agreement but not the costs to amend generator interconnection agreements other than their own because under this proposal the effects of downsizing will be assessed along with other factors unrelated to downsizing (e.g., Interconnection Request withdrawals) in the annual GIDAP reassessment process and it will not be possible to separate out those GIA amendments attributable to a downsizing project from amendments attributable to other causes. Therefore the ISO proposes to charge each

[23] The Interconnection Study Deposit applied in the ISO's GIP and GIDAP is equal to $50,000 plus $1,000 per MW of electrical output of the Generating Facility, up to a maximum of $250,000. The ISO is proposing to omit the variable term for purposes of the downsizing deposit. As the ISO previously stated during the development of the one-time downsizing opportunity, the ISO reviewed historical cost data from past queue cluster studies and found that, on average, queue cluster study costs have not exceeded $50,000 per interconnection customer.

downsizing project to cover only the cost of amending its own GIA. Although $10,000 per amended GIA was the amount used in the one-time downsizing process, sufficient information is not yet available for the ISO to ascertain whether that amount will be adequate. Rather than propose a specific amount in this straw proposal, the ISO will wait and make a proposal in the draft final proposal based on the best available information at that time.

- Withdrawal of a downsizing request. For the one-time downsizing process each downsizing generator had two opportunities to withdraw their downsizing request. First, because a generator downsizing study had never previously been performed and because downsizing customers faced uncertainty regarding the ultimate costs of the downsizing studies when submitting its downsizing request, each downsizing generator was provided with an opportunity to withdraw its generator downsizing request after being given a preliminary estimate of its obligation for downsizing study costs. Under this straw proposal, however, the ISO believes that this first withdrawal opportunity is no longer warranted because uncertainty about study costs has been reduced due to experience with the costs associated with queue cluster studies and the costs associated with the one-time downsizing process. The ISO does propose, however, to provide a downsizing generator an opportunity to withdraw if the ISO determines that its estimated responsibility for network upgrade costs may significantly increase.[24] If a downsizing generator withdrawals under this withdrawal opportunity, it will not receive a refund of the generator downsizing deposit.
- Clarification of relationship between downsizing and modification requests. Consistent with existing practice and because the ISO will be offering a downsizing opportunity on an annual basis, the ISO is proposing to clarify in the tariff that the ISO will not review requests to downsize a project's capacity pursuant to the general "material modification" review provisions. The purpose of making this clarification is to ensure that all downsizing requests are processed and analyzed in a manner that operates in harmony with the ISO's ongoing cluster study process. This will not, however, affect customers' rights to downsize during the interconnection studies, insofar as that right is explicitly provided in the applicable interconnection procedures, or the ability of customers to utilize the five percent "safe harbor" provision.[25]

Stakeholders are invited to comment on the ISO's straw proposal on this topic.

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[24] A significant increase is defined as a downsizing generator's responsibility for network upgrade costs increasing by more than five percent of $5 million, whichever is lower, from its cost responsibility identified in its interconnection facilities study, Phase II interconnection study report, or generator interconnection agreement (if it has executed one).

[25] In addition, this clarification will not prevent customers with partial termination provisions in their GIAs from exercising those rights consistent with the terms thereof.

4.2 Topic 2 – Disconnection of first phase of project for failure of second phase

4.2.1 *Scope of topic*

This topic relates to the rights one or more of the contracting parties under the *pro forma* generator interconnection agreement (i.e., the interconnection customer, the participating transmission owner, and the ISO) to declare another contracting party who fails to perform or observe any material term or condition of the GIA to be in breach of and to default on the GIA. The *pro forma* GIA provides that termination of the GIA is a potential remedy for default, and further provides for disconnection of the generating facility if the GIA is terminated. The question of whether and how a contracting party actually exercises these rights is entirely fact specific and can only be determined on a case-by-case basis. Section 4.2.4 below outlines the steps of the process that would have to be followed before a GIA breach could result in termination of the GIA.

The specific scenario addressed in this topic is where a portion or phase of the interconnection customer's project has been completed and has commenced commercial operation, and where the customer has determined not to complete all phases or the full MW size of the project as stated in the executed GIA (i.e., the stated MW size less the 5 percent "safe harbor"). In such a scenario, the termination of the GIA would mean that an operating generator that represents a portion or phase of a project could be disconnected from the ISO grid if the customer fails to fully complete the entire project.

This topic was originally suggested by the Large-scale Solar Association (LSA), CalWEA, and Tenaska in the March 2012 stakeholder survey, and was recently proposed again by LSA.[26] Stakeholders raising this issue assert that the possibility of the ISO fully terminating a GIA, in the situation where one phase of a project is already operating but a later phase of the project is cancelled, causes severe project financing problems. In the comments submitted on June 25 several stakeholders reiterated this concern, stating that the potential for disconnection would cause a financial institution to add a substantial risk premium or perhaps even decline to finance the project at all. Although the ISO has acknowledged this concern on the part of project developers, the ISO has also expressed its own concern about any blanket elimination of its right to terminate a GIA.

Several of the comments submitted on June 25 offered suggestions for potential approaches to address this concern, which the ISO has considered in developing the straw proposal described in the next subsection.

A related issue is the provision for "substantial performance" by an interconnection customer of its obligations under the GIA. In the GIP 2 initiative in 2011, the ISO clarified that a customer will have

[26] This issue was also raised in the complaint filed at FERC by CSOLAR earlier this year in FERC Docket No. EL13-37-000. FERC denied the complaint.

a safe harbor of five percent (5%) of its project's MW capacity as specified in the GIA. This means that the completed MW capacity of the project could be as much as 5 percent less than the MW specified in the GIA, for any reason, and the customer would be considered to have complied with "substantial performance" of its contractual obligations and thus would not trigger default of the GIA. In addition, if the completed project capacity is more than 5 percent below the MW specified in the GIA and the size reduction is the result of environmental or permitting limitations, the ISO will consider the merits of the reduction on a case-by-case basis.

Recent experience with projects in the interconnection process has suggested that the 5% safe harbor could be revised to allow size reductions up to "the greater of 5% of the project capacity or 10 MW" for any reason, and that this would be helpful to project developers without having adverse unintended consequences. Several stakeholders commented on this issue in their June 25 comments, and in response the ISO offers its straw proposal in the next subsection.

4.2.2 *Summary of stakeholder comments*

Several stakeholders reiterated the difficulty in obtaining project financing, or the increased cost of such financing, due to the risk that an operating generator could have its GIA terminated and be disconnected from the ISO grid due to the IC's failure to build the full MW of the project. In response to the ISO's request for suggested solutions to the problem, CalWEA clarified that it is asking the ISO to eliminate GIA termination only for those phases of a phased project that are completed (or being completed) if the later phases of that project do not materialize, rather than asking for a blanket waiver by the ISO of all termination rights in all circumstances. Other parties – CPUC, SunEdison, LSA, PG&E and Silver Ridge – agreed with CalWEA's position, while IEP suggested that options the ISO offers under topics 1 and 3 could enable the IC to avoid the scenario in question.

Most parties supported certain qualifications to elimination of GIA termination in the situation in question. CPUC, CalWEA and Six Cities said that the IC should be responsible for the full costs of network upgrades without reimbursement for the proportionate share of such upgrade costs that is associated with the project capacity that does not achieve commercial operation. PG&E said that an IC that utilizes this proposed provision in order to avoid termination of the GIA, must fully perform on all other provisions of the GIA including its financial responsibilities. Some other parties – IEP, LSA, Silver Ridge and SunEdison – suggested that the ISO perform a study to assess the impacts of the IC's cancellation of a project phase, for example to determine if the transmission capacity associated with the cancelled phase is used by other projects, and only withhold reimbursement to cover actual impacts or capacity that is unused by other projects.

On the question of redefining the safe harbor provision to read "the greater of 5 percent or 10 MW," CalWEA, IEP and Wellhead supported the change. CalWEA also asked that the 5 percent be increased to 10 percent. SCE said that 10 MW safe harbor reduction should not be allowed if it represented a significant percent of the overall project size.

4.2.3 *Straw proposal*

The ISO proposes to adopt the following modifications to the default provisions and termination rights specified under the pro forma GIA.

1. If an IC has completed and achieved commercial operation for a portion or phase of its project, the ISO will not seek to terminate the GIA *solely* for the IC's failure to complete the full MW required under the GIA (i.e., stated MW size less 5% safe harbor), unless it is determined that such failure results in adverse consequences that the IC cannot mitigate.

The ISO suggests that the above policy should address the concern stakeholders have been raising without compromising the ISO's ability to proceed toward GIA termination in instances where there are adverse impacts that must be addressed. At the same time, given the straw proposals being offered under topic 1 of this initiative to provide additional downsizing opportunities, the ISO wants to be sure that the policy proposed here would not create an incentive for customers to delay or avoid participating in a formal downsizing opportunity or somehow avoid responsibility for downsizing costs that could result from a downsizing study. The ISO must also ensure that this policy proposal does not create incentives for nonviable projects to linger in the queue or for customers to submit oversized project proposals. The ISO therefore proposes the following companion provision, which was suggested in some of the stakeholder comments, and the ISO is still considering whether any additional provisions are needed to prevent unintended uses of the proposed policy.

2. In a situation where the IC cancels a later portion or phase of its project and has not downsized the project either through a formal ISO downsizing opportunity or by exercise of partial termination provisions incorporated in its GIA, the IC will still be responsible for all security postings and costs associated with the full MW size of the project as stated in the GIA. Moreover, with regard to security postings and other costs for which the IC is normally reimbursed, the pro rata portion of such postings and costs associated with the cancelled portion or phase(s) of the project will not be eligible for reimbursement.

Assuming that ICs will have some additional downsizing opportunities to be developed under topics 1 and 3, the ISO does not support refining the cost responsibility provision further as some have suggested, by assessing the actual impacts of the cancellation of a project phase or determining whether the associated transmission capacity is used by other projects. To the extent the IC has other opportunities to downsize a project, where the ISO would assess actual impacts through a study process, the IC should use such opportunities. Under topic 2 the ISO is narrowly addressing the risk of disconnect issue and proposing to provide relief for this risk. The ISO does not intend to provide, through this limited waiver of GIA termination, yet another downsizing opportunity that might be more attractive than the other options being developed under this IPE initiative.

3. With regard to the idea of modifying the "safe harbor" provision to read "the greater of 5 percent or 10 MW," the ISO now proposes an additional refinement that would affect smaller resources. The ISO proposes to define the "safe harbor" to read "the greater of 5 percent or 10 MW, but no greater than 25 percent of the project's MW capacity as stated in its GIA."

The concept of "safe harbor" is narrowly intended to address situations where an IC completes most but not all of the MW capacity of its project. Under such a scenario, we would find that the IC has "substantially performed" with respect to the requirements of the GIA. If the reduction in size constitutes a significant percentage of the overall project size – for example, completing only 4 MW of a 20 MW project – it would not be consistent with the concept of "substantial performance" to allow this under the safe harbor.

4.2.4 *The process required to disconnect an operating project for GIA breach*

In summary, before a large or small generating facility can be disconnected from the ISO controlled grid due to the interconnection customer's default on a GIA, the customer must be notified of and fail to cure a default of the agreement, and FERC must accept a notice of termination filed by the ISO and/or PTO. The specific steps are described in more detail as follows.

- A breach of the interconnection agreement occurs if a party fails to perform or observe any *material* term or condition of the interconnection agreement.[27]
- A default occurs if a party fails to cure a breach of the interconnection agreement.[28]
- The ISO and/or PTO is required to provide a written notice of breach to the interconnection customer, providing an opportunity to timely cure the breach within a specified number of days:
    - Five (5) business days to timely cure a failure to post interconnection financial security required by the interconnection agreement.[29]
    - <u>For a large generating facility only</u>: Thirty (30) calendar days to timely cure any other breach of the interconnection agreement; provided, however, that if the cure cannot be completed within 30 calendar days, the defaulting party must commence

[27] Article 1 of ISO tariff Appendices V, Z, BB, CC, and EE (definition of breach).
[28] Attachment 1 of ISO tariff Appendices T and FF (definition of default); Article 1 of ISO tariff Appendices V, Z, BB, CC, and EE (definition of default).
[29] Article 6.4.2 of ISO tariff Appendices T and FF; Article 11.5.1 of ISO tariff Appendices Z, BB, CC, and EE.

the cure within 30 calendar days after notice and continuously and diligently complete such cure within ninety (90) calendar days from receipt of the notice.[30]

- For a small generating facility only: Sixty (60) calendar days to timely cure any other breach of the interconnection agreement; provided, however, that if the cure cannot be completed within 60 calendar days, the defaulting party must commence the cure within twenty (20) calendar days after notice and continuously and diligently complete such cure within six (6) months from receipt of the notice.[31]
- If a breach is not timely cured, or if a breach is not capable of being timely cured within the applicable period described above, the non-breaching parties may declare a default and terminate the interconnection agreement by written notice at any time until cure occurs.[32] The tariff does not, however, require the ISO or PTO to seek termination of the GIA upon declaring a default. The tariff states that the non-breaching party can "recover from the breaching party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or equity" regardless of whether or not the non-breaching party terminates the GIA. Thus, it is possible at this point for the contracting parties to try to identify and seek FERC approval of an alternative, equitable, non-termination remedy that is appropriate to the situation.

- A party that disputes a written notice of default can initiate dispute resolution procedures pursuant to the interconnection agreement.[33] Termination of the GIA would not occur while the dispute resolution procedures are in progress.
- Absent the parties identifying a mutually acceptable non-termination alternative, the ISO and/or PTO will file any notice of termination of the agreement with FERC. The termination can become effective only after FERC determines that termination of the GIA – and the consequences, in this case disconnection of the operational phase of the generating facility – are just and reasonable, and accepts the notice.[34]
- Upon approval by FERC to terminate the agreement, the parties will "take all appropriate steps" to disconnect the generating facility from the ISO controlled grid.[35]

[30] Article 17.1.1 of ISO tariff Appendices V, Z, BB, CC, and EE.
[31] Article 7.6.1 of ISO tariff Appendices T and FF.
[32] Article 7.6.2 of ISO tariff Appendices T and FF; Article 17.1.2 of ISO tariff Appendices V, Z, BB, CC, and EE.
[33] Article 10 of ISO tariff Appendices T and FF; Article 27 of ISO tariff Appendices V, Z, BB, CC, and EE.
[34] Article 3 of ISO tariff Appendices T and FF; Article 2.3.4 of ISO tariff Appendices V, Z, BB, CC, and EE.
[35] Article 3.3.3 of ISO tariff Appendices T and FF; Article 2.5 of ISO tariff Appendices V, Z, BB, CC, and EE.

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

The discussion on this topic that was in the June 3, 2013 issue paper is provided below in section 4.3.1. Stakeholder comments on the issue paper are summarized in section 4.3.2, including the ISO's analysis of those comments. The ISO's straw proposal is provided in section 4.3.3.

4.3.1 *Discussion in issue paper*

The general situation that this topic addresses is where an interconnection customer has submitted an interconnection request for a specific project, and then at a later time – generally in the process of negotiating the interconnection agreement – the interconnection customer wishes to develop the project in a number of phases, each phase having the same or different CODs, such that the MW capacities of the phases add up to the MW of the original project, and the COD of the last phase to be completed is the same as the COD of the original project. Within this general situation, customers have requested several different scenarios:

1. The interconnection customer will retain ownership of all phases and include them in a single GIA;
2. The interconnection customer wishes to assign ownership of each phase to a different owner, with all phases under a single GIA; and
3. The interconnection customer wishes to assign ownership of each phase to a different owner, with a separate GIA for each phase. {ISO note: Although interconnection customers have requested this, the ISO has not allowed separate GIAs for each phase.)

Stakeholders may wish to identify additional scenarios for discussion within this topic. Each of the scenarios will have some specific sub-issues that need to be addressed, as discussed below.

This topic is supported by many 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 and/or make financing more manageable as long as the parties involved (e.g., the different limited liability companies or LLCs) are "related" to the entity that submitted the interconnection request. The ISO permits interconnection customers to develop a project in phases, which are reflected in the interconnection agreement. The ISO asked stakeholders in the April 8, 2013 scoping proposal to provide additional information so that the ISO could assess what additional capability is desired, and some stakeholders did provide this information in their written comments.

The ISO envisions that the scope of this topic would include interconnection customers up through Cluster 4. The ISO is open to discussing whether the topic should also include interconnection customers that apply under the GIDAP, but is concerned that consideration of GIDAP may make the entire topic more complicated and require more time to resolve. The GIDAP already provides certain opportunities to downsize projects that were not available under the GIP, and thus it may be difficult to assess whether there may be complications or unintended consequences from allowing expanded project phasing opportunities under the GIDAP. Moreover, because the ISO has not yet implemented a full cycle of the GIDAP, it is premature to assess how well the existing provisions meet the needs of interconnection customers.

This topic is not intended to cover phased implementation during construction to avoid damage to equipment or to ease testing ability for the project. The ISO already allows projects to test prior to completion of all reliability network upgrades, provided a Limited Operation Study determines that testing energy can be supported by the then current configuration of the grid. The ISO also already allows projects to achieve actual COD prior to the COD specified in the GIA if all reliability network upgrades and interconnection facilities are completed. Depending how far in advance, the interconnection agreement may need to be amended to effectuate this action, or parties may desire to amend the contract.

Provided below is a list of what the ISO allows under its business practice, based on current tariff provisions.

1. Only one interconnection request is allowed per proposed generation project.
2. Each interconnection request is reflected in one interconnection agreement. If the interconnection request relates to an expansion of an existing project, then the existing interconnection agreement can be amended to incorporate the expansion interconnection request. If the same entity (i.e., LLC) has two or more projects at the same point of interconnection, and the entity desires to aggregate the projects under one interconnection agreement the ISO will allow that configuration.
3. An interconnection customer is allowed to develop its project in phases, such that each phase may be planned to reach commercial operation at the same or a different date, subject to the reliability upgrades and interconnection facilities required for each phase being in service, as long as the last phase achieves commercial operation by the COD specified in the interconnection request for the project.
4. To date, the ISO has allowed, based on previous requests from customers, an interconnection customer to develop a project in a maximum of four phases. The ISO requested that stakeholders interested in phasing comment on whether more than four phases should be allowed and describe why this is needed.
5. Where an interconnection customer has developed its project in phases under a single GIA, 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 (typically set up as distinct LLCs) must agree to assume joint and several liability for

all of the obligations relating to the interconnection. This means that all of the owners are both individually and collectively responsible for all of the interconnection obligations.

Issues to be addressed for this topic include:

- The need for a minimum total MW size threshold for a project to be eligible for development in phases. For example, would it make sense to allow a 5 MW project to be developed in smaller phases?
- A maximum number of phases into which a project can be developed.
- A minimum MW size of each phase.
- Criteria that include both a minimum total MW threshold and a minimum phase size in MW or a percentage of the total project. For example, in its written comments on the scoping proposal PG&E suggests that "Projects > 20 MW may have additional phases, provided no additional phase is smaller than the larger of 20 MW or 10% of the nameplate capacity."
- When during the interconnection process an IC may request to implement a phased structure for its project.

Phasing of a GIA is different than the construction implementation and testing requirements for a solar PV or wind project. The ISO and PTOs are working with projects during testing to determine if a "little-p" phased implementation is needed to avoid damage to equipment (i.e., bring groups of collectors on line).

Interconnection customers have asked in the past to be able to divide their projects into phases as described above, but have requested arrangements where all of the co-owners do not have to agree to joint and several liability with respect to the interconnection obligations for the entire project. The ISO believes that if an interconnection customer desires to divide its project into phases as described above it is essential that the co-owners agree to joint and several liability for the obligations relating to the whole project. The ISO does not envision being persuaded in this stakeholder process to modify this practice. The ISO believes that this is a reasonable outcome that strikes the appropriate balances between allowing customers flexibility in developing their projects while at the same time ensuring that the ISO and participating transmission owner can effectively administer interconnection arrangements. In particular, the ISO does not believe that it should be in the position of having to navigate the contractual relationship between individual owners of phases with respect to projects that have been processed and studied as single interconnection requests and share interconnection facilities in order to administer and enforce the obligations set forth in its tariff and agreements.

4.3.2 *Stakeholder comments*

The following comments were received on this topic from stakeholders on June 25 in response to the June 3 issue paper.

CPUC – CPUC Staff do not at this time offer comments on the phasing parameters (MW sizes, number of phases) mentioned above. Interconnection Customers (ICs) should be able to request a phased structure up until the point of GIA execution, which we understand is when such requests are typically made now. However, ICs should understand (and should be provided information to help them assess) the potential benefits of requesting a phased structure as early as possible, since earlier determination of phasing might facilitate more efficient design or sequencing of transmission upgrades. Phasing is apparently already available under the GIDAP, and CAISO should further consider and explain why any useful phasing reforms should not also be applied to GIDAP-vintage ICs.

CalWEA - CalWEA cannot think of any other scenario outside of the three identified by the CAISO. Given that phases are driven by a range of commercial needs that cannot be anticipated, and given that there is no technical reason to limit project phasing, CAISO should not establish any size or timing limits for phasing a project. Further, even after the project has gone into full operation for its entire GIA size, if in the future its PPA expires and new commercial arrangements would require the project to be broken into smaller project sizes, that should be allowed.

IEP - IEP does not understand from the ISO's comments or discussion if the ISO or PTO's have had issues with large numbers of customers subdividing projects into unmanageable numbers of phases. It appears that the limit of "4" phases resulted from prior customer request, and indeed IEP expects that so long as the final phase must reach COD as per the original project that most projects will subdivide into a relatively small number of phases anyway. Ultimately, IEP believes that any phasing decisions should be up to the interconnection customer. If there must be limitations on phasing (and it would be helpful to understand why), IEP recommends setting a threshold of 4 phases up and until which the customer does not need to provide any explanation to the ISO. Beyond 4 and up to a maximum of 10 the ISO could require some justification regarding the need to split the project and provide that justification to the ISO whose approval would not be unreasonably withheld.

IEP believes that commercial terms will, in most cases, determine these sizes – as it will the number of phases – and as such need not have an arbitrary limit on size. That said, IEP does find concern in the potential for a project to split into phases that, had they been managed independently, would have been under the SGIP and not the LGIP. We realize that may not have been the intention of the customer but it could be the reality. We raise this concern only as far as the ISO may identify benefits for a "small" project getting LGIP treatment and therefore inequities for projects that didn't split into 20 MW or less phases.

IEP believes that the ISO would benefit the most stakeholders (developers and LSEs) by allowing a phased approach to be implemented as late as feasible in the interconnection process. The likelihood of an interconnecting customer will know their ultimate commercial position occurs later rather than earlier in the development cycle, and as such, a later opportunity to subdivide would be welcomed; certainly after the GIA is in place.

LSA - The CAISO should also let projects combine (e.g., to facilitate Stand-Along NUs), if all obligations to the CAISO and PTO are covered. (This possibility was mentioned in the earlier Scoping Proposal but was dropped without explanation in the Scoping Paper.)

LSA supports consideration of the third option listed in the paper – potential splitting of a project into multiple GIAs, and without "joint and several liability" provisions as long as all obligations to the CAISO and PTO are covered. In fact, this approach could be simpler than the current multiple-LLC structure and could also address the problems associated with cancellation of later project phases above (since an entire LGIA for that project/phase could be canceled). LSA was disappointed that the CAISO seemed to distance itself from this option and believes that it is worth considering in this initiative.

LSA has no objection to a 20-50MW or smaller minimum phase size, given commercial considerations (e.g., RFO participation limits).

LSA has no opinion on whether there should be a minimum total MW size threshold to be eligible to divide a project into phases.

LSA does not see any reason to limit the number of project phases.

LSA does not see any reason to limit the timing for dividing a project into phases. Phased projects are studied as entire projects in interconnection studies, so a later division into phases would not require any re-studies. In fact, this is one of the changes recommended below for a modification that should be allowed outside the MMA process.

PG&E – PG&E is open to a reasonable degree of additional phasing flexibility and suggests the following criteria, which it believes is an acceptable balancing of providing additional flexibility with managing the contract management and operational issues that excessive flexibility would create:

a) ≤20 MW projects may have up to two phases, with no individual phase smaller than 5 MW

b) > 20 MW projects may have additional phases, provided no additional phase is smaller than the larger of 20 MW or 10% of the nameplate capacity

PG&E believes 10 MW should be the minimum size for projects to be split into multiple phases.

The maximum number of phases should be based on the project size, with large projects being allowed more phases. In no case should projects exceed 10 phases.

PG&E believes the timing of phasing requests should be limited to after the Phase I or Phase II study results meeting. Following execution of an IA, modifications to project phasing might also be allowed provided the milestone schedule and funding schedule for all PTO-built upgrades and IC-built standalone network upgrades is not modified.

Silver Ridge – Silver Ridge supports consideration of the third option listed in the paper – potential splitting of a project into multiple GIAs, and without "joint and several liability" provisions as long as all obligations to the CAISO and PTO are covered. While the CAISO included this option in the Issue Paper, it appeared to pull back in the June 11th conference call, leaving confusion about whether this option would be considered. In fact, this approach could be simpler than the current multiple-LLC structure and could also address the problems associated with cancellation of later project phases above (since an entire LGIA for a later project/phase could be canceled).

Silver Ridge has no objection to a 20-50MW or smaller minimum phase size, given commercial considerations (e.g., RFO participation limits).

Silver Ridge believes that projects smaller than 20 MW need not be phased.

The proposed 20-50 MW minimum phase size would naturally limit the number of phases – no further restrictions are needed.

Silver Ridge does not see any reason to limit the timing for dividing a project into phases. Phased projects are studied as entire projects in interconnection studies, so a later division into phases would not require any re-studies. In fact, this is one of the changes recommended for a modification that should be allowed outside the MMA process. Silver Ridge believes that changes in project phasing (dividing into phases, adding phases, splitting projects into multiple projects/GIAs, or combining projects) should be allowed without an MMA study, assuming that no applicable CODs are moved forward and that the IC continues to bear its share of allocated transmission costs.

Six Cities – The Six Cities are not, at this time, proposing for the ISO's consideration any additional scenarios related to the dividing of projects into phases other than those described at page 29 of the issue paper. However, the Six Cities support the ISO's current requirement that when a project is divided into phases under a single GIA with different owners, all of the co-owners remain jointly and severally liable for all obligations related to the interconnection for the full project and are individually and collectively responsible for all interconnection obligations for the full project. The Six Cities concur with the ISO that joint and several liability as among owners of phased projects is "essential" (see Issue Paper at 31) and that the ISO should not be compelled to navigate contractual relationships among phased project owners in order to administer and enforce the GIA and associated tariff requirements. Thus, the Six Cities support the ISO's position that no change in this practice is warranted.

The Six Cities have no position on the following issues at this time:

- What thresholds should be used in allowing projects to be broken into multiple phases;
- Should there be a minimum total MW size threshold to be eligible to divide a project into phases;
- Should there be a maximum number of phases into which a project can be divided;
- Should there be a minimum MW size for each phase;
- Should criteria be imposed that include both a minimum total MW threshold and a minimum phase size in MW or a percentage of the total project; and
- When during the interconnection process should an IC be allowed to request to implement a phased structure for its project?

SCE - SCE believes the ISO is overreaching if it were to expand phasing beyond the three scenarios identified – (1) IC retains ownership of all phases and includes all phases in a single GIA; (2) IC assigns ownership of each phase to a different owner, with all phase under a single GIA; (3) same as (2) except separate GIA for each phase. SCE does, however, agree with the ISO that it is essential for co-owners agree to joint and several liability for the obligations relating to the whole project, if this type of phasing agreement is permitted. Any additional phasing would further complicate an already overly complex process.

SCE generally responds to questions 2 – 7 below as follows. Irrespective of thresholds, the breaking of a single interconnection request into multiple phases or generation projects must come with certainty that progress will be made on all phases or "generation projects" that constitute a single interconnection request. Absent such certainty, the queue will transform from one that is clogged by projects failing to make progress towards commercialization, to one that is clogged with partially built projects that include portions that are unviable. Such outcome can hinder the PTO's ability to execute on upgrades in a timely manner as actual need of physical upgrades is tied not only to physical interconnection but also to the amount of actual generation materializing. It should also be understood, and in all likelihood expected, that moving towards this approach will come with a high degree of certainty that partially constructed projects will exist. As a consequence, the tariff and GIA provisions should clearly spell out timeframes to complete full projects as well as what will happen to unconstructed phases of a single interconnection request. In addition, a careful examination should be made that evaluates the potential impact to PTO's financing obligations associated with partial construction. If such examination is not made prior to allowance, it is conceivable that financing obligations for upgrades could shift to the PTO's since queued behind projects can state that they do not need to finance the upgrade given that such upgrades are in someone's GIA.

SunEdison - SunEdison is open to the ISO clarifying its phasing policy but encourages a solution that does not hinder ICs' ability to phase projects.

Wellhead - The ISO is rightfully concerned about creating a windfall commodity – a piece of a long held queue position that is not subject to provisions which allow the ISO to remove it from the queue. There should be some nexus between the initial and the reformulated/phased project. For example, it would not be reasonable to allow a 500 MW gas fired project that has been in the queue for many years to change technology and then break itself into twenty-five 20 MW projects. That is clearly well beyond any intent of the developer when the interconnection request was filed. That said, the market has changed significantly and it is not unreasonable for a project that was originally contemplated as, for example, 50 MW to now be developed as three smaller projects. And it would also not be unreasonable for the ISO to look for some reasonable form of relationship between the various phases (i.e. the interconnection request was not simply a queue speculator looking to broker the queue position as a commodity).

ISO summary of stakeholder comments – The following is a summary of the written comments discussed above, organized by subject area in the form of questions.

<u>Should phasing be allowed?</u>

SCE - Breaking a single interconnection request into multiple phases must come with certainty that progress will be made on all phases that constitute a single interconnection request, and tariff and GIA provisions should spell out timeframes to complete full projects as well as what will happen to unconstructed phases of a single interconnection request, including potential impacts to PTO's financing obligations associated with partial construction.

SunEdison - Open to ISO clarifying its phasing policy, but encourages solution that does not hinder interconnection customer's ability to phase projects.

Wellhead - Should be some nexus between initial and reformulated/phased project and it would not be unreasonable for ISO to look for some reasonable form of relationship between various phases, i.e. interconnection request was not simply a queue speculator looking to broker queue position as a commodity.

<u>Which interconnection customers will breaking projects into phases be available to?</u>

CPUC - ISO should explain why phasing reforms should not be applied to customers that seek interconnection through the GIDAP.

<u>When can interconnection customer submit a request for phasing?</u>

CalWEA - Should not establish any timing limits for phasing a project - even after project has gone into full operation for its entire GIA size.

LSA and **Silver Ridge** - Do not see any reason to limit timing for dividing a project into phases.

CPUC - Should be able to request a phased structure up until the point of GIA execution.

IEP - Should be able to subdivide after the GIA is in place.

PG&E - Should be limited to after the Phase I or Phase II study results meeting.

Should there be a MW size threshold for a project to be eligible to be divided into phases?

CalWEA - Should not establish any size limits for phasing a project.

IEP - Need not have arbitrary limit on size, but does find concern in potential for project to split into phases that, had they been managed independently, would have been under SGIP and not LGIP.

PG&E - 10 MW should be minimum size for projects to be split into multiple phases.

Silver Ridge - Projects smaller than 20 MW need not be phased.

LSA and **Silver Ridge** - Have no objection to a 20-50 MW or smaller minimum phase size, given commercial considerations.

Should there be a limit on the number of phases allowed?

LSA - Do not see any reason to limit number of project phases.

IEP - If there must be limitations on phasing, recommend setting a threshold of four phases up and until which the customer does not need to provide any explanation to ISO; beyond four and up to a maximum of 10 ISO could require some justification regarding the need to split project and provide that justification to ISO whose approval would not be unreasonably withheld.

PG&E - ≤20 MW projects may have up to two phases with no individual phase smaller than 5 MW, and > 20 MW projects may have more than two phases provided no additional phase is smaller than the larger of 20 MW or 10% of the nameplate capacity, but in no case should projects exceed 10 phases.

Silver Ridge - Proposed 20-50 MW minimum phase size would naturally limit the number of phases – no further restrictions are needed.

Once project is phased, can phasing plan be modified?

PG&E - Following execution of IA, modifications to phasing might be allowed provided milestone schedule and funding schedule for all PTO-built upgrades and IC-built standalone network upgrades are not modified.

Silver Ridge - Changes in project phasing (dividing into phases, adding phases, splitting projects into multiple projects/GIAs, or combining projects) should be allowed without an MMA study, assuming that no applicable commercial operation dates are moved forward and that the interconnection customer continues to bear its share of allocated transmission costs.

Can projects be broken into phases without joint and several liability provisions?

Six Cities - Support current requirement that when a project is divided into phases under a single GIA with different owners all of the co-owners remain jointly and severally liable for all obligations related to interconnection for full project and are individually and collectively responsible for all interconnection obligations for full project - no change in this practice is warranted.

SCE - Essential for co-owners agree to joint and several liability for the obligations relating to whole project if this type of phasing agreement is permitted.

Can there be multiple interconnection agreements for one interconnection request?

LSA and **Silver Ridge** - Support consideration of potential 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.

4.3.3 *Straw proposal*

The ISO's straw proposal for this topic is as follows.

1. An interconnection customer will be allowed to develop its project in phases, such that each phase may be planned to reach commercial operation at the same or a different date, subject to the reliability upgrades and interconnection facilities required for each phase being in service, as long as the last phase achieves commercial operation by the commercial operation date specified in the interconnection request for the project. Once a phased structure for a project is agreed upon, it will be incorporated into the customer's GIA.
2. The option for an interconnection customer to develop its project in phases will be available to interconnection customers in all interconnection queues, including GIDAP.
3. 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.
4. An interconnection customer that is seeking to phase an interconnection request must contact the ISO and request phasing. If the request for phasing comes after the interconnection studies have been completed, the request for phasing will go through the material modification request process and the request for phasing must be agreed to by the ISO and applicable participating transmission owner as part of the GIA negotiations.
5. There will not be a requirement that an interconnection request must be of a certain MW size to be eligible to request phasing, i.e., all interconnection requests are eligible to request phasing no matter what MW size they are.
6. There will not be a limit on the total number of phases allowed per interconnection request, i.e., there will be no maximum number of phases allowed per interconnection request.
7. There will not be a limit on the MW size of each phase.
8. Because phasing may involve different dates for the commercial operation of phases, then the ISO will require that no more than one phase can reach commercial operation each month. 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 GIA, any request to modify the phasing plan will need to be negotiated with the ISO and PTO and the GIA will need to be amended.
10. The ISO will not allow one interconnection request to be broken into multiple interconnection agreements. However, the ISO will continue to allow an interconnection customer to develop its project in phases under a single interconnection agreement, and will allow the phases to have different owners, provided that all of the owners are affiliates of the interconnection customer and all of the co-owners agree to assume joint and several liability for all of the obligations relating to the interconnection and specified in the GIA, i.e., all of the owners are both individually and collectively responsible for all of the interconnection obligations specified in the GIA. The ISO continues to believe that requiring joint and several liability is an important predicate to permitting developers to assign individual project phases to different owners. Because each GIA relates to a single project, it would be unreasonable for the ISO and PTO to be required to attempt to parse liability between the various phase owners, or to assume the risk of under- or non-recovery of the financial obligations set forth in the GIA, which would be inherent in a situation in which each owner has distinct and severable liabilities. Requiring all of the owners of the phases of a single project to assume joint and several liability protects the ISO and PTO by ensuring that, if the need arises, they can enforce the obligations of the GIA against phase owners both jointly and individually.

The ISO does not see a compelling reason to impose generalized restrictions on which interconnection customers can phase their projects, nor how an interconnection customer may choose to structure its phasing. The ISO will require that interconnection customers formally request phasing, and, if the request for phasing comes after the interconnection studies have been completed, agreement will be required from both the ISO and the applicable participating transmission owner for phasing to be allowed as part of the GIA negotiations. The ISO agrees with stakeholder comments that commercial considerations will drive how phasing is requested and it is unlikely that the ISO will see interconnection customers requesting unreasonable phasing plans.

The ISO will allow phasing for all interconnection requests, including interconnection requests that come in under the GIDAP tariff provisions. The GIDAP tariff currently includes provisions that contemplate phased projects. The GIDAP tariff provisions regarding the allocation of transmission plan deliverability ("TPD") already state that the scoring criteria may apply to a portion of the MW of a project and, on this basis, TPD may be allocated to a portion of a project on the basis of that portion's score. These provisions should apply to phased projects in a straightforward manner.

The ISO does not see a compelling reason to restrict interconnection customers as to when they can request phasing. Commercial considerations may cause interconnection customers to request a phased project either at the beginning of the interconnection process, after the interconnection studies have been completed, after the interconnection agreement has been executed, or after the initial phases of the generation portion of the project have come on-line. The ISO proposes to allow interconnection customers to request phasing at any time in the life cycle of development of the project. Any approved phasing will be incorporated into the study models in all future Phase II studies.

With respect to the issue of splitting projects into multiple interconnection agreements, there appears to be a misunderstanding regarding a sentence that was included in the June 3 issue paper regarding "scenario 3" that stated, "The interconnection customer wishes to assign ownership of each phase to a different owner, with a separate GIA for each phase." The June 3 issue paper discussion was meant to provide a list of the various things that stakeholders have requested over the years. It was not intended as a list of possible options that the ISO is exploring in the IPE initiative. The June 3 issue paper is correct in noting that interconnection customers have requested an interconnection arrangement as described in scenario 3. However, in hindsight the paper also should have clearly stated the ISO's policy and business practice: which is that the ISO has never allowed separate interconnection agreements for each phase and the ISO is not proposing to change its policy in the IPE initiative on this aspect of the interconnection process. The ISO views the tariff provision that there will be one interconnection agreement for each interconnection request as a fundamental provision of the interconnection process. This outcome best aligns with the ISO's policy goals of promoting realistic and viable interconnection requests and effective queue management policies. The ISO recognizes that interconnection customers and stakeholders desire flexibility in the interconnection process. However, the ISO notes that it already provides significant flexibility to interconnection customers, such as through the co-tenancy provisions and the downsizing opportunities that are discussed in this straw proposal. Moreover, interconnection customers have the option, at the outset, of choosing to file separate interconnection requests for contemplated phases or filing a single request that would include phases. The former approach will result in separate GIAs for each phase. As a result, the ISO is not proposing to change its policy, which is to allow only one interconnection agreement per each interconnection request.

4.4 Topic 4 – Improve Independent Study Process

The purpose of the Independent Study Process (ISP) effort will be to align the tests for independence with the overall ISP intent. As written, the ISP allows for a project to be studies for reliability network upgrades (RNUs) on an expedited study track. ISP projects requesting Full Capacity Deliverability Status (FCDS) are required to be studied for deliverability network upgrades (DNUs) separately in the standard cluster study process along with other projects in the next scheduled cluster study. The current tests for independence require that the project be electrically independent of Interconnection Requests included in an existing cluster, and in addition, must be electrically independent of any other project that is currently being studied under an earlier-queued ISP Interconnection Request. To determine independence the project must pass both the flow impact test and the short circuit test to determine whether the project would have had to share in the cost responsibility allocation of any network upgrades required by any existing cluster projects or ISP projects currently under study. The test against "network upgrades" does not delineate between RNUs and DNUs and the practice has been to test against both. This process, while being consistent with the tariff, does not appear to be consistent with the practice of performing the reliability studies independently and performing the FCDS study as part of a cluster. As the tariff is currently written it would be more appropriate to change the language from testing against "network upgrades" to "reliability network upgrades." Furthermore, the ISP is overly complicated and needs to be simplified and made more straight forward. If specific details of the study methodology are needed for ICs to understand, that detail may be more suited to be incorporated into the appropriate BPMs.

Lastly, the behind the meter expansion (BTME) component of the ISP has shown to be an option of increasing interest and this area of the ISP will be reviewed for improvements based on experience the ISO has gained in processing behind the meter expansion requests and on ICs interest in the BTME process.

4.4.1 *Stakeholder comments*

CPUC – Believes that improvements to the Independent Study (IS) process could be valuable. The CAISO proposes to explicitly provide that the independence test and the actual IS itself can be based on consideration of Energy-Only status, i.e., considering reliability but not delivery network upgrades. This should increase the potential for some projects to qualify for IS. If an intended Full Capacity generation project might thus have Energy-Only status for a number of years this may impact contracting. CPUC Staff request clarification of (and hope that) pursuit of IS via an Energy-Only route should not hinder or delay a generation project's ability to ultimately achieve Full Capacity status (although it might not expedite achieving FC status).

NRG – NRG would be interested in an ISP that allows for behind the meter expansion, especially in the context of adding BTM storage to a project that would increase the amount of hours (but not the amount of instantaneous output) that a solar project could provide energy.

SCE – The independent study process evaluation should be extended to also include an assessment of whether or not the behind the meter expansion can be integrated into the system independent of construction activities associated with other projects. As an example, it does no good to pass all ISP filters only to discover that we cannot execute on the project until we finish someone else's work. As a consequence, this conclusion would suggest that the project is not entirely independent of the rest.

PG&E - Agrees with the ISO's inclusion of behind the meter expansion track as part of the ISP track. PG&E wishes to participate, and in particular wishes to work with stakeholders on establishing appropriate criteria for behind the meter expansions to qualify for the ISP.

Wellhead – The ISP was created in recognition that some projects could be well located and developed to commercial operation much faster than the interconnection process would otherwise allow. It seems that projects which were the model for the original ISP process would no longer qualify. There needs to be a process so that projects which can be developed quickly are not held hostage to the long, and frequently delay, interconnection process. And a project going through ISP should not be delayed/prevented from getting deliverability. It's not clear why behind the meter expansion should be treated differently if it is going to increase the total output to the grid at any instant in time.

4.4.2 *ISP working group*

In the June 3, 2013 Issue Paper the ISO proposed an ISP working group (ISP-WG) be formed 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 consists of a team of engineers along with policy related participants 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, volunteer participants from the generation development community with both technical expertise and policy interests will participate on the working group. The ISO looks forward to stakeholder participation in the working group and at that time will address the comments received to date. Further stakeholder input will be requested after the straw proposal is developed by the working group. It is clear that addressing the issue of behind the meter expansion is important to the stakeholders and this topic will be addressed during the working group.

The working group will present its recommended revisions to the ISP process to the entire IPE stakeholder group as straw proposals are developed to the point of being ready for broader stakeholder input.

4.4.3 *ISP working group schedule*

The ISP-WG will strive to hold its first meeting by July 19 and meet biweekly thereafter 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 by the end of 2013 and be taken to the ISO Board of Governors for approval in early 2014. Initially the ISP-WG and the Fast Track working group will hold back-to-back working group meetings as most of the participants will be participating in both working groups.

4.5 Topic 5 – Improve Fast Track

The purpose of the Fast Track (FT) effort will be to develop 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 will be in scope, the current 5 MW FT project size limitation will not be open 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 the 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. More broad revisions to the FT process will occur after the FERC final ruling on the SGIP NOPR is available.

4.5.1 *Stakeholder comments*

CPUC – Believes that improvements to the Fast Track process could be valuable and look forward to results of a working group effort in this area.

4.5.2 *FT working group*

In the June 3, 2013 Issue Paper the ISO proposed a FT working group (FT-WG) be formed 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 consists of a team of engineers along with policy related participants 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, volunteer participants from the generation development community with both technical expertise and policy interests will participate on the working group. The working group will present its recommended revisions to the FT process to the entire IPE stakeholder group as straw proposals are developed to the point of being ready for broader stakeholder input.

4.5.3 *FT working group schedule*

The FT-WG will strive to hold its first meeting by July 19 and meet biweekly thereafter until a final proposal is developed that has been vetted with the broader IPE stakeholder group. The ISO looks forward to stakeholder participation in the working group and at that time will address the comments received to date. Further stakeholder input will be requested after the straw proposal is developed by the working group.

It is anticipated that the final FT proposal will be completed by the end of 2013 and be taken to the ISO Board of Governors for approval in early 2014. Initially the FT-WG and the ISP-WG will hold back-to-back working group meetings as most of the participants will be participating in both working groups.

4.6 Topic 13 – Clarity regarding timing of transmission cost reimbursement

In its April 12, 2013 tariff amendment in FERC Docket No. ER13-1274, the ISO proposed 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[36] 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.[37]

In its May 14, 2013 filing in the same proceeding, the ISO clarified that the purpose of these revisions was to ensure its tariff is internally consistent as interpreted by a prior FERC order. FERC had previously determined that the ISO's generator interconnection procedures provide, with respect to non-phased projects, refunds for network upgrades begin upon the commercial operation date of the generating facility.[38] The ISO reaffirmed that its proposed changes to Section 11.4.1 of Appendices CC and EE only serve to implement FERC's prior order and remove any ambiguity from the ISO tariff regarding what conditions apply to repayment of network upgrades cost for non-phased projects.

Thus, the ISO has already addressed, and FERC has ruled on, this issue with respect to existing tariff requirements. Therefore, 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 the existing rules in the IPE initiative. Moreover, having added the requirement for phased facilities that upgrades must first be in service before reimbursement commences in GIP 2, the ISO does not believe that policy should be revisited here. The ISO agrees, however, 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..

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[36] 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.

[37] 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).

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

4.6.1 *Stakeholder comments*

Following publication of the June 3 issue paper, the ISO solicited stakeholder feedback on this topic by posing a number of questions in the June 11, 2013, stakeholder comments template. Using a question and answer format, these stakeholder comments are summarized below.

Stakeholders were asked to express their views on going forward whether cost reimbursement should require both commercial operation and network upgrades in service.

CPUC – Believes that phased projects should receive reimbursement via the same timing and criteria as non-phased projects. There should be reimbursement when an early phase of a project meets the required conditions, but that reimbursement should only involve deposited funds associated with upgrades identified for that phase, not any additional deposit amounts for construction of transmission linked to later phases. Requiring only commercial operation, not completion of network upgrades, as the criterion for reimbursement of deposits appears to be not only reasonable but also an incentive for PTOs to strive to complete network upgrades by the stated COD. At a minimum, projects reaching commercial operation by their stated COD should be reimbursed a substantial portion of their construction deposits, regardless of the advancement of the associated transmission construction.

CalWEA – If a generator reaches COD before its delivery network upgrades have been completed (or construction even begun), then that generator should not be required even to post security for such upgrades and should receive all delivery network upgrade financial security deposits that it may have posted up to that time.

IEP – Does not support the proposal.

LSA – Adamantly opposes the proposal, on the same grounds that it opposed such reimbursement conditions for phased projects. And since the issue was recently decided by FERC no reason to bring it up again. Simply seeks clarification that a phased project with all phases completed be treated the same as completed non-phased projects.

PG&E – Agrees transmission cost reimbursement needs to be clarified on a going forward basis. Supports clarification that reimbursement for generator-funded upgrades can begin at COD, provided reimbursement is capped at the lesser of (a) capital investment in completed upgrades (e.g., if 80 percent of a generator's upgrades, on a financial basis, are in operation then reimbursement could not exceed 80 percent) or (b) for phased projects the pro-rate share of network upgrades required for the phases that have achieved COD. For pre-Cluster 6 changes versus current practice for existing projects with PPAs would only serve to transfer wealth between ratepayers and developers. Loosening rules for projects with existing PPAs would simply boost the returns generators' projects at the expense of ratepayers.

Six Cities – Eligibility for cost reimbursement should require both (i) that the project has achieved commercial operation and (ii) the required network upgrades to be in service.

SCE – There is no basis for the difference in treatment currently in the GIP surrounding the commencement of transmission credits for phased versus non-phased generating facilities. Transmission credits should commence with the completion of two events: the commercial operation date of the facility (or phase of facility for phased projects) and the in-service date of required network upgrades for the facility (or phase of facility for phased projects). FERC has invited the ISO to make necessary revisions to the existing tariff language to make clear that the commencement of transmission credits should be conditioned upon both the commercial operation date of the generation facility and the in-service date of the associated network upgrades.

4.6.2 *Potential options for stakeholder consideration*

Under existing rules, transmission cost reimbursement for non-phased projects begins upon the COD of the generating facility and for phased projects network upgrades must first be in service before reimbursement begins. As already stated, the ISO does not propose to consider modifications to existing rules for transmission cost reimbursement for customers that have already received a generator interconnection agreement, regardless of whether they represent phased or non-phased projects. The ISO maintains that it has already addressed, and FERC has ruled on, this issue with respect to existing tariff requirements.

However, on a going forward basis, the ISO has indicated that it is open to at least considering other approaches. That said, based on a review of stakeholder comments, there does not appear to be agreement among stakeholders on what that approach should be. Some stakeholders assert 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 asserts 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 COD).

This suggests the following options for consideration on a going forward basis:

- 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.

The ISO requests stakeholder express their preference for a particular option and explain their reasons why.

4.7 Topic 14 – Distribution of forfeited funds

The ISO tariff provides for forfeiture by an interconnection customer (IC) of certain portions of its study deposits and interconnection financial security (IFS) postings upon withdrawal of its interconnection request from the ISO generator interconnection queue. The ISO manages interconnection study deposits on account to cover the costs of interconnection studies as they are incurred by the ISO and PTOs. After the study process is completed and the IC has executed the generator interconnection agreement (GIA), the IC is refunded any excess of its study deposits beyond the actual study costs it is responsible for. The relevant PTO manages IFS funds in conjunction with construction of the network upgrades required for the IC. IFS funds that have not been used by the time the IC withdraws will be deemed forfeited, except where the IC is eligible for refund of a portion of those funds in circumstances specified in the ISO tariff.

The forfeited funds are currently distributed to scheduling coordinators on an annual basis, in proportion to the amount of grid management charge (“GMC”) that each scheduling coordinator paid during the calendar year in which the funds were deemed forfeited. This is the same as the approach by which the ISO distributes the funds collected as penalties assessed to market participants. A number of stakeholders have suggested that there are more appropriate ways to distribute these funds, for example, to reduce the costs of the generator interconnection process or the costs of constructing transmission facilities needed to support generator interconnections.

This section provides some relevant information on the magnitude of forfeited funds, a summary of stakeholder comments, and a preliminary review of the options the ISO is considering based on stakeholder input. At this point the ISO wants to have further discussion on these options and is not yet offering a single straw proposal as its preferred option.

4.7.1 *Amount of forfeited funds 2009-2012*

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 $40.1 million, including interest. This amount comprises approximately $29.8 million in study deposits and approximately $10.3 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.

Table 6 – Amount of forfeited funds 2009-2012

Forfeited Funds	Total
Forfeited Study Deposits - 2012*	$ 15,886,748
Forfeited Interconnection Financial Security Deposits - 2012*	$ 4,566,413
	$20,453,161
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
Forfeited Interconnection Financial Security Deposits – 2010	$805,819
	$13,365,984
Total Forfeited Amounts	$40,150,659
**Estimated 2012 collections (not yet distributed)*	

4.7.2 *Timeline for implementing potential tariff changes*

Based on the 2013 timeline for the IPE stakeholder process in 2013 and approvals from the Board and FERC in 2014, the earliest implementation of tariff changes would be 2014. Tariff changes regarding the distribution of forfeited funds approved by FERC in 2014 would become effective prospectively. If we consider the approach as applying annually based on the calendar year, then the change would be implemented for forfeited funds collected during 2015, which would typically be re-distributed in 2016. However the ISO is open to considering alternative distribution schedules that do not necessarily align with the calendar year so that a new distribution approach could be implemented earlier, if appropriate.

4.7.3 *Summary of Stakeholder Comments*

This subsection provides a summary of stakeholder comments received on June 25, 2013 in response to four questions posed by the ISO as part of the June 11, 2013 IPE Conference Call.

Question 1: If some stakeholders believe that the scheduling coordinator approach should be abandoned, then do stakeholders have any specific ideas for alternative approaches to the distribution of forfeited funds?

PG&E – PG&E reiterates prior comments that, in instances when a PTO is still required to build network upgrades despite withdrawal of generation from the queue, forfeited funds go toward the cost of upgrades for which the IFS posting was made. The overarching principle that PG&E supports is that forfeited funds should be used to offset the adverse impacts of generation withdrawing from the queue. Remaining funds, if any, could then be used to offset stranded costs of incremental work not reimbursed by generators or allocated per the existing methodology.

Six Cities – The Six Cities support changes to the current approach of allocating forfeited funds to Scheduling Coordinators. Forfeited funds should first be used to pay for or offset the cost of any restudy activities and upgrades associated with the interconnection request (including any additional or modified upgrades that may be necessary as a consequence of withdrawing an interconnection request from the queue). Interconnection customers that have forfeited funds should not be entitled to reimbursement for any portion of their forfeited funds that are used to pay for upgrades. To the extent that any additional funds remain after having been used for restudy and upgrade costs, such additional funds should be distributed to ISO transmission customers in the form of a credit against the ISO's Transmission Access Charge.

CPUC – If specific current interconnection customers can be clearly identified as facing identifiable study cost increases attributable to actions causing study deposit forfeiture, the forfeited study deposits in question should be used to offset those specific customers' study cost increases.

If specific transmission projects that cannot be avoided can be clearly identified as incurring funding shortfall attributable to actions causing forfeiture of security (construction) deposits, the forfeited security deposits should be used to offset the costs of those specific transmission projects, including avoiding increases in other customers' security deposits. To the extent that these distributed forfeiture funds are never reimbursed, this should be reflected in (and all parties should support) corresponding reduced rate-based asset amounts for these transmission projects.

CAISO and stakeholders may discuss whether a portion of the forfeited security deposits (for construction) should ultimately be refunded if the transmission projects in question become needed by future interconnection customers, but only within the next yearly planning/interconnection cycle.

Otherwise, forfeited funds should be used to offset the TAC. If distribution methods a, b and c prove unworkable or undesirable, then method d alone should be used.

IEP – IEP believes that the current allocation of forfeited funds to the SC's is inappropriate and inconsistent with their source. IEP recommends that the ISO consider applying forfeited study, design, and construction funds in order to offset transmission interconnection costs that are currently collected in the TAC, including use of those funds to conduct the studies required to determine if a delay in COD has a "material impact" on other queue projects.

LSA – Forfeited Study Deposit funds should be used to offset study costs for the projects remaining in the same cluster, since those ICs will likely pay more for the remaining studies in the interconnection process.

SCE – SCE believes the current process works and should be retained. Further, as the ISO points out, FERC has already determined that the ISO's distribution of forfeited IFS funds is just and reasonable.

CalWEA – As CalWEA has indicated in the past, all forfeited funds from the interconnection process, regardless of whether they are study security deposits or financial security deposits, should be used to pay for network upgrades that result from interconnection study processes.

Question 2: Please comment on the possible use of forfeited IFS funds to offset resulting cost increases for projects remaining in queue as a way to mitigate impacts of withdrawals on other interconnection customers.

PG&E – PG&E supports this approach, provided it also offsets any PTO-funded costs caused by queue withdrawal; for example, if a PTO must self-fund an upgrade or portion of an upgrade above the remaining queue's cumulative cost cap. See comments on #1.

Six Cities – Please see the Six Cities' response to Question No. 1 above.

IEP – While IEP does not prefer the approach as described, we do view the suggested approach as an improvement over the current protocol of distributing funds to the scheduling coordinators.

LSA – LSA supports this concept – see #1 above.

SCE – SCE opposes using forfeited IFS funds to offset the resulting cost increases for projects remaining in queue as a way to mitigate impacts of withdrawals on other interconnection customers.

CalWEA – Please see CalWEA's response to Question 1 above.

<u>Question 3:</u> Please comment on the stakeholder-suggested idea of applying forfeited IFS funds to a PTO's transmission revenue requirement to reduce the transmission access charge and thereby benefit ratepayers who ultimately bear the costs of the transmission upgrades.

PG&E – PG&E views this as being a blunter instrument than application to offset the direct adverse impacts of queue withdrawals. PG&E would prefer a methodology that more directly offsets cost causation/adverse impacts.

Six Cities – Please see the Six Cities' response to Question No. 1 above.

IEP – This suggestion is similar to our comments above in item # 1; however, IEP's preference would be that forfeited funds related to the interconnection process be "rolled up" to the ISO to lower its cost of interconnection-related services funded by the TAC.

LSA – Ratepayers bear the costs of Network Upgrades ultimately because FERC has ruled that they benefit from these system enhancements. Therefore, LSA believes that its proposal is more equitable than this one.

SCE – SCE opposes applying forfeited IFS funds to a PTO's transmission revenue requirements. Transmission ratemaking is complex and most ISO PTOs determine their base transmission revenue requirements ("TRR") based on a forecast of costs, meaning that any forfeit revenues received by such a PTO would not affect their base TRR dollar for dollar unless the revenue was forecast, which is unlikely. Thus, it presents a significant administrative challenge to PTOs. When combined with the fact that the current tariff does not allow PTOs to capture all of the expenses associated in negotiating an agreement, imposing this additional burden may not be justified.

CalWEA – Please see CalWEA's response to Question 1 above.

<u>Question 4:</u> Please comment on the possible use of forfeited funds by the ISO and PTO for study costs previously incurred that an interconnection customer defaults on.

PG&E – PG&E would support this as a good use of remaining funds after application to offset costs per the method described in item #2 above.

Six Cities – Please see the Six Cities' response to Question No. 1 above.

IEP – Insofar as costs of customer default contribute to the TAC, IEP would support the ISO's proposed use of forfeited funds in this manner.

LSA – LSA has no objection to using Study Deposit funds for this purpose prior to implementation of its suggestion above for those funds

SCE – SCE does not understand this proposal, since PTOs get study deposits upfront, there should be no study costs that are defaulted on by the customer (unless PTOs spend more than is deposited). SCE looks forward to receiving clarity and having further discussion on this topic during the stakeholder process.

CalWEA – Please see CalWEA's response to Question 1 above.

ISO clarification – As further clarification, the suggestion behind question 4 is for when the PTO and ISO combined spend more than is deposited and the IC defaults on the invoice. SCE is correct that PTOs do not incur the cost of uncollectible study amounts when an IC defaults because these charges are billed to the customer by the ISO, not the PTO.

4.7.4 *Initial review of options*

Based on comments received to date, most stakeholders favor developing a different way to distribute the forfeited funds. Several stakeholders favor using the funds to offset ICs' costs of interconnection (e.g., the cost of studies or the construction costs for interconnection-related transmission facilities).

The ISO has considered the comments and constructed the table below to characterize the main approaches at a high level. The ISO believes that the most fundamental question to be addressed is: *Who should be the beneficiaries of the distribution of funds?* The table below therefore emphasizes this question. For the next round of comments, the ISO requests that stakeholders offer more detailed suggestions about how exactly they believe the targeted set of beneficiaries should be specified.

Within several of the options – see options 5, 6 and 7 – there could be different ways to specify the targeted beneficiaries as particular subsets of ratepayers or ICs. In the case of options 2-5 the beneficiaries are transmission ratepayers. In options 6 and 8 the beneficiaries are parties who pay the ISO's GMC and, in some variations, the costs of the PTOs. In option 7, there could be a number of possible ways to benefit particular subsets of ICs.

In identifying the options below, for simplicity the ISO as considered all forfeited funds as a single bucket of money, rather than distinguishing between how to distribute the study deposit funds and how to distribute the IFS funds. As this initiative moves forward, the ISO is open to considering different distribution approaches for the two categories of funds, if that seems appropriate, but points out that this would make the distribution process more complicated.

The ISO is not expressing a preference at this point, but will instead pursue the assessment of the pros and cons of these options in terms of considerations such as fairness, incentives, economic efficiency, ease of implementation, etc. The ISO requests that stakeholders refer to these basic criteria as they advocate for or against the options below.

	Option	Beneficiaries	Comments
1	Retain current approach and distribute to SCs	SCs	Requires no changes Most stakeholders oppose

2	Reduce TAC system wide; allocate pro rata shares to TRRs of all PTOs	All transmission ratepayers	Very little stakeholder support Not related to location of withdrawn project
3	Reduce TAC by PTO area; entire amount to TRR of PTO where withdrawn project was interconnecting	Ratepayers in territory of PTO where project is withdrawn	Very little stakeholder support
4	Costs of network upgrades (NU) associated with the withdrawn project, if still needed	Ratepayers that would otherwise reimburse NU costs PTO, in a case where PTO would have to up-front fund some portion of needed NU Later queued project that otherwise would face higher costs for needed NU	Reflects principle that funds should offset impacts of project withdrawal Ratepayers benefit as the portion of NU costs covered by forfeited funds does not need to be reimbursed Still need to specify what to do with excess funds, if any
5	Some larger set of NU for interconnections	Some subset of ratepayers, depending on how the target set of NU is selected	Need to specify the scope of NU to be funded – Same cluster? Same geographic area? Other criteria?
6	Costs of studies & other interconnection services, to offset costs recovered through GMC.	Payers of GMC. One possible use would be to pay for the new re-assessment study created under GIDAP.	Could cover both ISO and PTO costs. If there are any excess forfeited funds, retain them and apply to the next cycle.
7	Costs of studies & other interconnection services, to offset costs for other ICs	To reduce study costs for some subset of ICs. Need to better define which ICs would benefit. E.g., apply funds only to offset study cost increases for ICs (see table below)	Does this diminish the cost responsibility ICs should expect when they enter the queue?
8	ISO and PTO GIA negotiation costs	ISO and PTOs; i.e., GMC and PTO budgets	ISO and PTOs currently absorb the cost of GIA negotiations in nearly all cases. Would require administrative processes to track costs.

Example: Use of forfeited funds to offset study cost increases for ICs remaining in queue (see option 7 above).

The table below, which is based on actual queue data, shows that the total impact of project withdrawals on the study costs of projects remaining in queue is estimated to be $100,000 per year. Considering that over $20 million was forfeited in 2012, this use of the funds would make a very small dent in the total.

ESTIMATED IMPACT OF STUDY PROJECT WITHDRAWALS								
Allocation Costs at set-up				Increased study costs due to withdrawal				
	A	B	C	D	E	F	H	H
Project Type	Number of Projects in Group	Total Charges to be Allocated	Cost per Project (B/A)	Number of Projects Withdrawn	Remaining Number of Projects (A-D)	Revised Amount to be Allocated (B/E)	Increased cost per project in Cluster (F-C)	Total Costs to be Offset using Forfeited Funds (H * E)
Cluster 4	100	$100,000	$1,000	10	90	$1,111	$111	$10,000
Cluster 5	60	$350,000	$5,833	5	55	$6,364	$530	$29,167
Cluster 6	50	$200,000	$4,000	10	40	$5,000	$1,000	$40,000
Downsizing	15	$100,000	$6,667	3	12	$8,333	$1,667	$20,000
							ESTIMATED TOTAL STUDY COSTS TO BE OFFSET	$99,167

4.8 Topic 15 – Inverter/transformer changes

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 is broadening the topic somewhat in response to stakeholder comments. The title of this topic remains the same for this straw proposal to avoid any confusion, but may be modified in subsequent papers for this initiative. 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.

4.8.1 *Stakeholder comments*

PG&E - Aside from inverter/transformer changes, PG&E is not aware of other areas where bypassing the material modification review would be appropriate. See PG&E comments Topic 7, question 2. PG&E believes that the IC should submit an updated interconnection request and that the ISO should provide written acknowledgement of the change.

Silver Ridge - Silver Ridge believes that changes in project phasing (dividing into phases, adding phases, splitting projects into multiple projects/GIAs, or combining projects) should be allowed without an MMA study, assuming that no applicable CODs are moved forward and that the IC continues to bear its share of allocated transmission costs. Project downsizing where the IC agrees to pay its original share of allocated transmission costs likewise should be allowed without an MMA study.

Minor changes to inverters and transformers (e.g., vendor changes), and perhaps other equipment, should be allowed without an MMA study, if the electrical properties assumed in the interconnection studies are generally the same – i.e., if the new equipment is the same size and has the same rating and connection configuration as the prior equipment.

CalWEA - All technology changes should be allowed to take place without a formal material modification review if they fit within certain well established criteria that could be developed as part of these proceedings. These criteria would generally state that the technology change should lead to similar or superior performance as the original equipment.

All changes should be presented by the project developer to the CAISO with developer's analysis as to why such change would meet the CAISO established criteria for "automatic" acceptance. CAISO should then review the analysis and if it meets its standards, it should approve the change.

CPUC - CPUC Staff support providing greater transparency and structure regarding the material modification review process including clarification of what modifications do not require such review. We understand that the CAISO and PTOs are already moving to document such greater transparency and structure via BPM revisions, and we encourage and look forward to those revisions. It is clear that future changes in inverter/transformer design and operation may be important, given anticipated types of generator additions. We support having material modification review address inverter/transformer-related modifications as efficiently as possible, including clear and reasonable (not more conservative than necessary) criteria for determining when inverter/transformer modifications do not require formal material modification review.

SCE - SCE is willing to explore the possibility of permitting inverter/transformer changes without a material modification review. Interconnection customers should be required to provide the ISO and PTO with written notification of the specific technological and other relevant changes which did not require a material modification review in order to assess all of the potential impacts resulting from such modification.

SunEdison - SunEdison agrees that certain changes such as inverter and transformer changes should be immaterial enough that MMA should not be necessary. Additionally, it is recognized that there is a need to enforce MMA timeline.

LSA - LSA believes that changes in project phasing (dividing into phases, adding phases, splitting projects into multiple projects/GIAs, or combining projects) should be allowed without an MMA study, assuming that no applicable CODs are moved forward. COD delays of up to three years should not require a MMA study.

Minor changes to inverters and transformers (e.g., vendor changes), and perhaps other equipment, should be allowed without an MMA study, if the electrical properties assumed in the interconnection studies are not impacted. LSA suggests a small working group (which LSA would volunteer for) to develop a list of applicable equipment changes, with "checklists" for each, that would be exempted from MMA studies.

LSA also supports development of standard MMA timelines, and timelines for resulting GIA revisions, to ensure prompt study results and contract modifications. Standard notifications and timelines could be developed by the working group – LSA has no specific suggestions at this time.

4.8.2 *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 which provides transparency into the modification review that is done by the ISO and PTO. In addition, where needs for tariff changes have been identified in this section, the ISO would incorporate those into the proposals for topics 1 and 2. Modification is defined as any changes to the data that is included in the interconnection request. Material Modification is defined as a modification that has a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.

Modifications that are allowed without a modification review and approval:

- Between Phase I and Phase II:
  - a decrease in the electrical output (MW) of the proposed project;
  - modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; and
  - modifying the interconnection configuration.

After Phase II Study Report is complete, an interconnection customer's request to change project technology, size, Point of Interconnection, interconnection facilities, network upgrades, or milestones anytime outside of the interconnection study process or project results meetings must go through a modification review to determine if the modification is material.

The Participating TO may also initiate a material modification review if there are changes to the network upgrades or interconnection facilities. When the Participating TO initiates a request the ISO will make reasonable efforts to inform the Interconnection Customer and obtain their concurrence with the proposed change. Although Participating TO initiated change requests may be thoroughly researched by the requestor prior to submitting the request, the ISO reviews changes proposed by the Participating TO in order to create documentation for the decision and to ensure a complete and independent analysis of the request.

Any project changes that are outcomes of the Phase II results meeting will go through the Material Modification review procedure.

The team performs this modification review to ensure that:

- requested changes are not a material modification and will not impact other queued customers;
- transmission and generation schedules are in line;
- final decisions are compliant with ISO tariff requirements; and
- ISO business analysis is consistently applied to all projects.

Please note that although it can be interpreted that the tariff automatically allows some changes without review, such as a request to change Commercial Operation Date (COD) within the “3-year window”, all change requests that deviate from the Phase II study results or do not meet the criteria outlined above for changes allowed without modification review need to be evaluated for potential impacts to other queued customers to ensure that ISO business analysis is consistently applied to all projects.

4.8.2.1 Timeline

The target for each modification review is 35 business days to the customer, but if that is not feasible due to work volume or other extenuating factors, the ISO will keep the customer and other business units updated as to the status of the request. The 35 day timeline will not start until all of the necessary technical documents have been received.

4.8.2.2 ISO Process

Requests to change project technology, size, Point of Interconnection, interconnection facilities, network upgrades, or milestones should be submitted to queuemanagement@caiso.com for processing. Requests should include a description of the changes and applicable technical information or diagrams, updated project milestones, and a project status describing reason for the change. If the technical data is not complete, the ISO will work with the customer to obtain the information needed for the assessment. The description of the reason for the change is the starting point for the ISO business assessment. Except for changes to Appendix B milestones, change requests should be accompanied by complete package of Attachment A to the Interconnection Request.

4.8.2.3 Unacceptable Requests

As an example, some requests may require the ISO and the Participating TO to perform a detailed reliability and deliverability re-study. Serial projects may request a re-study. However, projects in the cluster process are not entitled to a re-study. The ISO's BPM on Generator Interconnection Procedures, Other Modifications Section 9.3.3[39], references the ability to modify generators after the Phase II studies have been completed.[40]

> *Where the ISO has granted modifications in a post Phase II Interconnection Study phase, the ISO must be able to evaluate the change and find it acceptable without the need to undertake a re-study to meaningfully evaluate it.*

4.8.2.4 Acceptable Requests

Specific to requests for size reduction, the ISO conducted a one-time downsizing opportunity in 2012-13 and is proposing under Topic 1 to offer additional opportunities annually. In addition a project's size can be reduced through the substantial performance provisions which include the one-time 5 percent "safe harbor":

1. 5% safe harbor – If the final MW capacity of the generating facility that is completed and achieves commercial operation is at least 95 percent of the MW capacity as specified in the generator interconnection agreement,[41] then the project is deemed to have met the substantial performance of the contract; and
2. If the final MW capacity is less than 95 percent of the GIA value, then the interconnection customer must reasonably demonstrate that the reduction is warranted due to reasons beyond the control of the interconnection customer consisting of one or more of the following:
    a. Failure to secure required permits and other governmental approvals to construct the generating facility at its total MW generating capacity specified in interconnection request after making diligent efforts.
    b. Written statement from the permitting or approval authority indicating that construction of the facility at the total MW size specified in interconnection request will likely result in disapproval due to significant environmental or other impact that cannot be mitigated.

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[39] https://bpm.caiso.com/bpm/bpm/version/000000000000159

[40] As noted above with respect to Topic 1, the ISO is proposing to clarify in its tariff that the ISO will not review requests for capacity reductions as part of a customer's general right to seek project modifications. Rather, customers will need to pursue such requests through the annual downsizing process being proposed under Topic 1.

[41] Current tariff refers to the MW amount that was studied in the Phase II study process rather than to the GIA. The ISO believes it is in keeping with the intent of this initiative to revise the tariff to refer to the GIA, to reflect the ability of the IC to utilize the safe harbor provision even after a downsizing request has been granted.

c. Failure to obtain legal right to use of the full site acreage necessary to construct/operate the total MW generating capacity size for the entire generating facility after making diligent efforts (only applies where an interconnection customer previously demonstrated and maintained its demonstration of site exclusivity).

Under scenario 2, in the instance that the project does not meet one of the above criteria, the request would be denied.

Also, the ISO plans consider as part of this stakeholder process whether revisions to this “greater than 5%” provision (i.e., scenario 2 above) are appropriate, in order to harmonize it with the annual downsizing and termination proposals (topics 1 and 2). The ISO submits for stakeholder comment two potential revisions to this provision:

(1) indicate that all requests for reductions greater than 5% that meet these criteria will be deemed to be downsizing requests to be included in the next downsizing window, and will be subject to all the requirements related to participation in such downsizing window; or

(2) treat capacity reductions greater than 5% that meet these criteria in accordance with the proposed mechanism relating to GIA termination set forth in topic 2 above.

The ISO requests that stakeholders provide feedback on these two alternatives.

Construction sequencing – If the project is under construction and the customer’s Commercial Operation Date is delayed by 6 months or less then changes in dates for In Service, Synchronization and Commercial Operation may be automatically approved. Such changes must be requested by the IC to allow the ISO and PTO to correctly model and manage the system.

4.8.2.5 Automatic Approvals

In the event that the Participating TO informs the ISO that a Reliability Network Upgrade is delayed and that a project will need milestone modifications due to that date change, the ISO will forward that information on to the ISO Planning Engineer. The ISO Planning Engineer will confirm the Participating TO’s conclusion and evaluate if any other projects are affected by the date change. The ISO will review the conclusion with the Participating TO before drafting a letter approving the change.

The COD extensions associated with a Participating TO’s delay in construction of upgrades should be commensurate. As an example if the new date for upgrade is January 1, 2015, then the In Service Date of the project should be within ~ 6 months of this new date (i.e. just because the upgrade is delayed does not give the IC an ability to further delay their project). In addition, the time between In Service, Synchronization and Commercial Operation should be similar to the number of days between these dates that were previously agreed to. Thus if the Synchronization date was 30 days after In Service Date, and the new In Service Date in March 1, 2015 then the new

Synchronization Date should be March 31, 2015, etc. The ISO will make reasonable efforts to inform the other affected Interconnection Customer(s) of the date change.

4.8.2.6 Engineering Analysis

In the event that the Participating TO was not included in the modification request the ISO will forward the request on to the applicable Participating TO. The ISO Planning Engineer will evaluate the request pursuant to ISO tariff Appendix U Section 4.4, Appendix T Section 6.2, Appendix Y Section 6.9.2, Appendix DD Section 6.7.2, or Appendix S Section 1.3.4. The ISO Planning Engineer will work in coordination with the Participating TO Planning Engineer.

4.8.2.7 Business Assessment

The ISO will perform a business assessment of the project. The purpose of the business assessment is to:

- ensure consistency of approach based on review of prior communications with the IC and Participating TO on this issue;
- ensure compliance with applicable tariff sections;
- ensure compliance with the executed IA or study results, as applicable;
- ensure consistent application of previous ISO business decisions;
- consider any factual circumstances beyond the control of the customer that necessitate granting the request; and
- consider the customer's progress toward project completion.

Consistent with these principles, the ISO will consider each material modification review on its own merits.

4.8.2.8 Drafting the Response

The ISO will draft a response letter based on the analysis provided by the Planning Engineers and the business assessment.

4.8.2.9 Participating TO Review

Once the draft is considered "ISO final", it will be sent to the Participating TO's for review and approval. If the Participating TO has substantive changes to the letter or disagrees with the conclusion reached by the ISO, the letter will return to the ISO team to review.

4.8.2.10 Notification Process

The final approved letter will be sent to the following:

- Interconnection Customer– via email and FedEx

- Participating TO

The ISO Analyst will:

- coordinate with the ISO contract negotiator to evaluate how best to memorialize the change in an Interconnection Agreement
- update RIMS with the approved changes

4.8.2.11 Modification Checklist

This checklist is provided as a guide and is representative of what the ISO tracks.

____ Request received from IC

____ Engineering Analysis – Material Modification engineering analysis is complete

____ Business Assessment – Material Modification assessment is complete

____ Participating TO Review – "ISO final" letter was approved by Participating TO and the ISO has agreement in email

____ Send final response to IC and Participating TO

____ Update files and RIMS

Appendix A

Steps and timeframes associated with the one-time downsizing opportunity		
Step no.	**Sequential steps in the generator downsizing process (Including citations to relevant ISO tariff sections)**	**Timeframe**
1	Each downsizing generator submits its generator downsizing request to the ISO. (Appendix GG Sections 2.3, 2.5.1) Each downsizing generator must meet all requirements of good standing of its interconnection request. (Appendix GG Section 2.4(2))	No later than the generator downsizing request due date, *i.e.*, 5:00 p.m. Pacific time on January 4, 2013
2	The ISO notifies each downsizing generator whether its generator downsizing request is deemed complete, valid, and ready to be studied. (Appendix GG Section 2.5.2.1) If the generator downsizing request is not deemed complete, valid, and ready to be studied, the process starts for requesting and providing additional information to address the deficiencies in the generator downsizing request. (Appendix GG Section 2.5.2.2)	No later than 10 business days after the generator downsizing request due date
3	The ISO issues a market notice when it has posted on its website (1) a listing of valid generator downsizing requests and (2) a preliminary estimate of the aggregate study costs for conducting the generator downsizing study. Issuance of this market notice opens the opportunity for each downsizing generator to withdraw its generator downsizing request pursuant to the information provided in the market notice, *i.e.*, opens the first withdrawal opportunity. (Appendix GG Sections 3, 5.1(i))	Following the generator downsizing request due date, in late January 2013
4	The ISO tenders a downsizing generator payment obligation agreement to each downsizing generator that has not thus far chosen to exercise the first withdrawal opportunity. (Appendix GG Section 6.1)	No later than 5 calendar days prior to the close of the first withdrawal opportunity as described in step 5
5	Close of the first withdrawal opportunity. (Appendix GG Section 5.1(i))	8:00 a.m. Pacific time on the sixth business day following issuance of the market notice described in step 3
6	Each downsizing generator that chooses not to exercise the first withdrawal opportunity must execute and return its tendered downsizing generator payment obligation agreement to the ISO. (Appendix GG Section 6.1)	Within 5 calendar days after tender of the downsizing generator payment obligation agreement as described in step 4
7	The ISO issues a market notice of the anticipated commencement and completion dates of the generator downsizing study. (Appendix GG Section 6.4)	January/February 2013
8	The ISO and participating transmission owners perform the generator downsizing technical assessment for the generator downsizing study. (Appendix GG Section 6; Attachment A to Appendix 4 of Appendix GG)	February - April 2013
9	The ISO provides written notice to each downsizing generator whose cost responsibility for network upgrades is expected to increase by more than five percent or five million dollars, whichever is lower, from the cost responsibility identified in its interconnection facilities study, Phase II interconnection study report, or generator interconnection agreement. Provision of this written notice opens the opportunity for each downsizing generator that receives such notice to withdraw its generator	April 2013

Steps and timeframes associated with the one-time downsizing opportunity		
Step no.	**Sequential steps in the generator downsizing process (Including citations to relevant ISO tariff sections)**	**Timeframe**
	downsizing request pursuant to the information provided in the notice, *i.e.*, opens the second withdrawal opportunity. (Appendix GG Section 5.1(ii))	
10	Close of the second withdrawal opportunity. (Appendix GG Section 5.1(ii))	8:00 a.m. Pacific Time on the eighth business day following provision of the written notice described in step 9
11	The ISO and participating transmission owners complete the generator downsizing study. The ISO provides a generator downsizing study report to each downsizing generator that has not exercised the first or second withdrawal opportunity and to each affected generator. (Appendix GG Section 6; Attachment A to Appendix 4 of Appendix GG)	Late June 2013
12	Each downsizing generator may request a generator downsizing study results meeting with the ISO and the applicable participating transmission owner(s). (Appendix GG Section 10)	Within 10 calendar days of receipt of the generator downsizing study report
13	Each affected generator may request a generator downsizing study results meeting with the ISO and the applicable participating transmission owner(s). (Appendix GG Section 10)	Within 14 calendar days of receipt of the generator downsizing study report
14	The ISO provides notice of updated posting amounts of interconnection financial security, if necessary, to each downsizing generator and affected generator whose cost responsibility for network upgrades and/or participating transmission owner's interconnection facilities changes between its earlier interconnection studies and the generator downsizing study. (Appendix GG Section 12(2))	Within 15 business days of the issuance of the generator downsizing study report
15	The applicable participating transmission owner(s) and the ISO tenders to each downsizing generator or affected generator a draft amendment to its executed generator interconnection agreement, if necessary, together with draft amended appendices. (Appendix GG Section 13) If the downsizing generator or affected generator has not yet executed a generator interconnection agreement, then the applicable participating transmission owner(s) and the ISO will, if necessary, tender a revised draft generator interconnection agreement with draft appendices. (Appendix GG Section 13) Also, the process subsequent to such tender for providing comments, negotiation, and execution and filing of a revised generator interconnection agreement, or an amendment to an executed generator interconnection agreement, including all timeframes, will be identical to the process set forth in Appendix Y Section 11, or as agreed to by the downsizing generator or affected generator, ISO, and participating transmission owner(s). (Appendix GG Section 13)	Within 30 calendar days after the ISO provides the generator downsizing study report
16	To the extent that a downsizing generator's cost responsibility for network upgrades or participating transmission owner's interconnection facilities increases or decreases, or an affected generator's cost responsibility for network upgrades or participating transmission owner's interconnection facilities decreases, adjustments to the interconnection financial security to conform to the updated amounts specified in the notice described in step 14 must be made. (Appendix GG Section	Within 30 calendar days after the issuance of the notice described in step 14

Steps and timeframes associated with the one-time downsizing opportunity		
Step no.	**Sequential steps in the generator downsizing process (Including citations to relevant ISO tariff sections)**	**Timeframe**
	12(2))	
17	The participating transmission owner and any third parties performing work related to the generator downsizing study on the downsizing generator's behalf must invoice the ISO for such work. (Appendix GG Section 2.12)	Within 75 calendar days of completion of the generator downsizing study
18	The ISO issues invoices to the downsizing generator based upon the invoices provided to the ISO as described in step 17 and the ISO's own costs for the generator downsizing study. (Appendix GG Section 2.12)	Within 30 calendar days after the invoices are provided to the ISO as described in step 17
19	Each downsizing generator that receives an invoice as described in step 18 must pay any invoiced amount not covered by the downsizing generator's generator downsizing deposit. (Appendix GG Sections 2.7, 2.12)	Within 30 calendar days of the date of the invoice