Interconnection Process Enhancements

Draft Final Proposal

Topics 4, 5, and 13

March 25, 2014

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Interconnection Process Enhancements

Draft Final Proposal for Topics 4, 5 and 13

1 Executive summary

In this paper the ISO offers its current proposals for the remaining three topics in the Interconnection Process Enhancements ("IPE") initiative – improve the independent study process (Topic 4), improve the fast track process (Topic 5), and clarity regarding the timing of transmission cost reimbursement (Topic 13). This paper includes a draft final proposal for Topics 4 and 5, and a second revised straw proposal for Topic 13.

The 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 process and associated interconnection agreements.

The ISO launched the IPE initiative with the issuance of a scoping proposal paper on April 8, 2013. The scoping proposal accomplished two steps: first, it assembled a comprehensive list of potential GIP-related topics for consideration in this initiative; and second, it selected twelve topics from the comprehensive list of topics for proposed inclusion in the scope of the IPE initiative. Based on stakeholder feedback on the April 8 scoping proposal, the ISO added additional topics which resulted in a scope of fifteen topics for the IPE initiative.

Seven of the fifteen topics addressed queue management issues (*i.e.*, Topics 6-12[1]). The ISO took the proposals for Topics 6-11[2] to the September meeting of the ISO Board, received Board approval, and filed the associated tariff amendments on September 30, 2013 with the Federal Energy Regulatory Commission ("FERC") in Docket No. ER13-2484. FERC accepted those tariff amendments.

Two of the fifteen topics addressed generator project downsizing (Topic 1) and the risk of disconnection (Topic 2). The ISO presented proposals for these two topics to the ISO Board on November 7, 2013 and received Board approval. The ISO is currently working with stakeholders to develop the associated tariff amendment for filing with FERC.

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

[2] Topic 12 was later withdrawn from the IPE initiative.

Through consultation with stakeholders it was ultimately determined that two of the fifteen topics – clarify tariff and GIA provisions related to dividing up GIAs into multiple phases or generating projects (Topic 3), and material modification requests (Topic 15) – could be addressed through the Business Practice Manual (BPM) change management process. The BPM effort on Topic 15 is complete; that work for Topic 3 is in progress.

In late 2013, discussions with stakeholders led the ISO to move Topic 14 (use of forfeited funds) into the Generator Interconnection and Deliverability Assessment Procedures ("GIDAP") reassessment initiative which is scheduled to go before the ISO Board at its May 2014 meeting.

Thus, of the original fifteen topics in the IPE initiative, the remaining topics are Topics 4, 5, and 13. These topics are the subject of this paper and draft final proposals are offered on Topics 4 and 5, and a second revised straw proposal is offered on Topic 13. At this point, the ISO anticipates taking topics 4 and 5 to the ISO Board in May and topic 13 to the Board in July.

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.[3] Successful completion of the interconnection process is a necessary step in the development of a new generation project and is one of the challenges faced by generation developers.

The ISO is committed to continuously reviewing potential enhancements to its generator interconnection process to reflect changes in the industry and to better accommodate the needs of interconnection customers. Pursuant to this commitment, the ISO has conducted a series of stakeholder processes over the past several years to improve the generator interconnection process. These include Generation Interconnection Process Reform ("GIPR") held in 2008-09, Generation Interconnection Procedures Phase 1 ("GIP 1") in 2010, Generation Interconnection Procedures Phase 2 ("GIP 2") in 2011, and Generation Interconnection Procedures Phase 3 ("GIP 3") in 2012.[4]

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[3] Some projects request interconnection to the distribution systems of the participating transmission owners through their wholesale distribution access tariffs ("WDATs").

[4] GIP 3 was started in early 2012 but later deferred while the one-time 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 number of other topics. The ISO explained that only a limited number of topics would be included in the initial stakeholder effort to ensure timely resolution and implementation of those topics. 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

The ISO launched the latest in this series of stakeholder processes to review and improve the generator interconnection process when it published the Interconnection Process Enhancements ("IPE") initiative scoping proposal on April 8, 2013.[5] Rather than follow the usual sequence of beginning an initiative with an issue paper, the ISO identified the development of a scoping proposal as a necessary first step. Its purpose was twofold. First, it assembled a comprehensive list of potential topics in one place from a number of sources including:

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

Second, the scoping proposal selected a set of potential 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 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, 2013 scoping proposal for inclusion in the scope of the IPE initiative. Based on stakeholder feedback received following the release of the April 8 scoping proposal, the ISO expanded the scope of the IPE initiative by three topics and posted an issue paper on June 3, 2013 addressing the resulting scope of fifteen topics.[6]

Table 1 lists these fifteen topics.

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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 developing a one-time generator project downsizing opportunity through a separate stakeholder initiative. FERC accepted an ISO tariff amendment to implement one-time project downsizing opportunity effective December 2012.

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

[6] The remaining topics, which the ISO did not initially recommend be in scope, are described in section 4 of the April 8, 2013 scoping proposal: http://www.caiso.com/Documents/ScopingProposal-InterconnectionProcessEnhancements.pdf

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

Following release of the June 3, 2013 issue paper, the ISO held a stakeholder web conference on June 11, 2013 and stakeholders provided written comments on June 25, 2013.

As explained in both the April 8, 2013 scoping proposal and the June 3, 2013 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 enable the proposals for these topics to go to the ISO Board for approval earlier than the non-queue management topics in this initiative. Consistent with this approach, while the June 3, 2013 issue paper was a conventional issue paper for some of the fifteen topics in scope, it served as a straw proposal on others. Specifically, for the seven topics addressing queue management issues (*i.e.*, Topics 6-12[7]), the ISO offered straw proposals in the June 3, 2013 paper. For the remaining eight topics (*i.e.*, Topics 1-5[8] and 13-15[9]), the ISO was not prepared to offer a proposal in the June 3,

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

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

2013 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, 2013 issue paper and receipt of stakeholder comments, the ISO posted a draft final proposal for Topics 6-12 on July 2, 2013. This was followed with a stakeholder web conference on July 10, 2013 and written stakeholder comments on July 16, 2013. The ISO took the proposals for Topics 6-11 to the September 2013 meeting of the ISO Board, received Board approval, and filed the associated tariff revisions with the Federal Energy Regulatory Commission (FERC) on September 30, 2013 in Docket No. ER13-2484.[10] As a result, Topics 6-11 were not addressed in the subsequent straw proposal paper published on July 18, 2013. The ISO's decision to withdraw Topic 12 from the IPE initiative was addressed in a paper published on November 8, 2013.

On July 18, 2013 the ISO published a straw proposal paper addressing Topics 1-5 and 13-15 (*i.e.,* the non-queue management topics). The July 18 paper offered straw proposals for Topics 1, 2, and 3. The July 18 paper also presented a straw proposal for Topic 15 (called "inverter/transformer changes" at the time, but renamed to "material modification review"); however, implementation of the proposal on Topic 15 was accomplished through the business practice manual change process rather than through tariff changes.[11] In the July 18 paper the ISO was not yet prepared to offer straw proposals on Topics 4, 5, 13, and 14; nevertheless, the discussion of these four topics provided additional analysis and, for some, offered options for stakeholder consideration (*e.g.,* for Topics 13 and 14). The ISO presented the July 18 paper during a stakeholder web conference held on August 8, 2013 and received written comments from stakeholders on August 22, 2013.

On September 12, 2013, the ISO published a draft final proposal for Topics 1 and 2. After receiving stakeholder feedback, the ISO made further refinements and modifications to the draft final proposal which it published in a pair of addendums – the first on September 24, 2013 and the second on October 21, 2013. The ISO Board approved the proposals for Topics 1 and 2 at its November 7, 2013 meeting. A stakeholder process to develop the associated tariff revisions subsequently ensued.

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

[10] FERC accepted the tariff revisions in *California Independent System Operator Corporation*, 145 FERC ¶ 61,172 (2013), effective December 3, 2013 as requested by the ISO, subject to minor tariff revisions that the ISO subsequently filed on compliance with FERC's order.

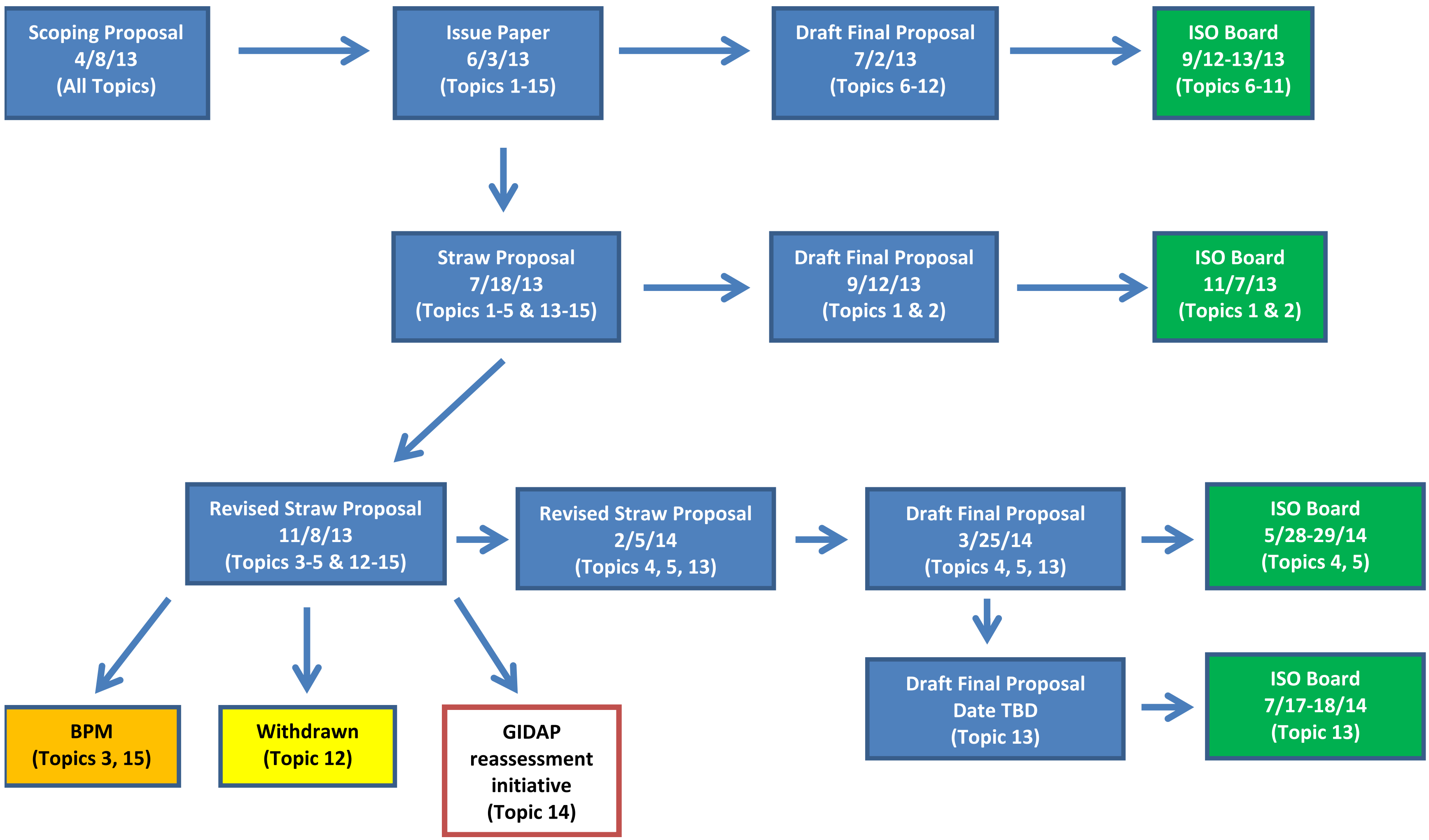
[11] In an effort to consult with stakeholders prior to initiating the BPM change management process in January 2014, the ISO began a series of stakeholder web conferences on topic 15, with the first such web conference held on October 29, 2013. The ISO submitted the resultant BPM changes into the BPM change management process as Proposed Revision Request (PRR) 700 on January 13, 2014. PRR 700 was approved in March 2014.

On November 8, 2013, the ISO published a paper addressing the remaining seven topics in the IPE initiative (*i.e.*, Topics 3-5 and 12-15). Initial or revised straw proposals were offered on Topics 3-5, 13, and 14. Although a straw proposal was already offered for Topic 15 in the July 18, 2013 paper, the ISO nonetheless included the topic once again in the November 8 paper to maintain clarity and restate its intention to address this topic through the BPM change management process. In the November 8 paper, the ISO also proposed to implement its proposal for Topic 3 through the BPM change management process. With respect to Topic 12, the ISO used the November 8 paper to clarify for stakeholders that the ISO was withdrawing the topic from further consideration in the IPE initiative.

At the time the November 8 paper was published, it was anticipated that proposals for those topics requiring tariff revisions (*i.e.,* Topics 4, 5, 13, and 14) would be presented to the ISO Board for approval at its March 2014 meeting; however, this plan was subsequently modified in two respects. First, discussions with stakeholders led the ISO to move Topic 14 (use of forfeited funds) into the GIDAP reassessment initiative which is scheduled to go before the ISO Board at its May 2014 meeting. This was done to consider the possibility of using such funds to offset increases in network upgrade funding requirements for customers remaining in the queue and for PTOs that result from project withdrawals. Second, it was determined that Topics 4, 5, and 13 could benefit from additional stakeholder feedback and that taking these three topics to an ISO Board meeting beyond March 2014 would make this possible. At this point, the ISO anticipates taking Topics 4 and 5 to the ISO Board in May and Topic 13 to the Board in July.

Consequently, this paper addresses the three remaining topics in the IPE initiative: Topics 4, 5, and 13. Draft final proposals are offered for Topics 4 and 5, and a second revised straw proposal is offered on Topic 13. The ISO anticipates that it will post a draft final proposal for Topic 13 in May.

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


Scoping Proposal
4/8/13
(All Topics)
Issue Paper
6/3/13
(Topics 1-15)
Draft Final Proposal
7/2/13
(Topics 6-12)
ISO Board
9/12-13/13
(Topics 6-11)
Straw Proposal
7/18/13
(Topics 1-5 & 13-15)
Draft Final Proposal
9/12/13
(Topics 1 & 2)
ISO Board
11/7/13
(Topics 1 & 2)
Revised Straw Proposal
11/8/13
(Topics 3-5 & 12-15)
Revised Straw Proposal
2/5/14
(Topics 4, 5, 13)
Draft Final Proposal
3/25/14
(Topics 4, 5, 13)
ISO Board
5/28-29/14
(Topics 4, 5)
Draft Final Proposal
Date TBD
(Topic 13)
ISO Board
7/17-18/14
(Topic 13)
BPM
(Topics 3, 15)
Withdrawn
(Topic 12)
GIDAP
reassessment
initiative
(Topic 14)

3 Stakeholder process next steps

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

Table 2 – Stakeholder process schedule

Step	Date	Milestone
Revised straw proposal (Topics 4, 5, 13)	February 5	Post revised straw proposal
	February 13	Stakeholder meeting (web conference)
	February 28	Stakeholder comments due
Draft final proposal[12] (Topics 4, 5, 13)	March 25	Post draft final proposal
	April 2	Stakeholder meeting (web conference)
	April 16	Stakeholder comments due
Board approval (Topics 4, 5)	May 28-29	ISO Board meeting
Draft final proposal (Topic 13)	(to be determined)	Post draft final proposal
	(to be determined)	Stakeholder meeting (web conference)
	(to be determined)	Stakeholder comments due
Board approval (Topic 13)	July 17-18	ISO Board meeting

4 Topics

This section presents the ISO's draft final proposals for Topics 4 and 5, and a second revised straw proposal for Topic 13, based on a consideration of stakeholder comments received on February 28 in response to the February 5 paper.

4.1 Topic 4 – Improve Independent Study Process

The purpose of the Independent Study Process (ISP) enhancement effort is to revisit the tests for independence and to align the process timeline with the overall ISP intent. To qualify under the ISP, the interconnection customer must provide, along with its interconnection request, an

[12] This paper includes a second revised straw proposal for Topic 13.

objective demonstration that inclusion in a queue cluster will not accommodate the desired commercial operation date (COD) for the generating facility. Under the existing process, an interconnection request submitted in the ISP will result in the generating facility having its electrical independence tested against the study results of projects in the most recently completed studies of the latest cluster as well as earlier ISP projects in the ISO queue. If the determination of electrical independence by the ISO and applicable participating transmission owners (PTOs) is not completed prior to the close of any given open cluster application window, the customer's ISP project will have to wait for the studies of the recently closed cluster application window to be far enough along to be able to determine its electrical independence against the projects in that latest cluster. The tariff revisions to improve the ISP will be made solely to the GIDAP, because all new requests by customers to take part in the ISP will be pursuant to the GIDAP.

4.1.1 ISP working group

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

The ISP working group held bi-weekly meetings starting from July 29, 2013. The intent was to hold working group meetings on a bi-weekly basis until a final proposal is developed that has been vetted with the broader IPE stakeholder group. The ISP working group and the Fast Track working group typically held back-to-back working group meetings as most of the participants in one working group also participated in the other.

The ISP working group reviewed the existing process and identified the following areas as candidates for possible enhancement:

- Criteria for ISP eligibility
- Process and timeline enhancements
- Tests for electrical independence
- Clarification of behind-the-meter (BTM) expansion and its impact on the net qualifying capacity (NQC)

4.1.2 Stakeholder comments

On February 5, 2014 the ISO presented a revised straw proposal on this topic. Stakeholder comments received by February 28, 2014 are summarized below.

Pacific Gas and Electric Company (PG&E) –

PG&E supports the updated straw proposal. In particular, PG&E believes the CAISO's proposal to separately meter and trip behind-the-meter capacity expansions is an excellent solution to the deliverability/NQC status issue raised by LSA.

California Public Utilities Commission (CPUC) staff –

CPUC Staff support BTM expansion not impacting previously assigned deliverability status of a resource's pre-BTM expansion capacity. We believe that generation projects undergoing BTM expansion and independent study should be eligible to apply for additional deliverability available over the transmission network via the Annual Full Capacity Deliverability Option if this would be more efficient and timely than entering the next cluster study, provided that the project in question meets all reliability and other requirements applicable to customers seeking independent study, and to customers pursuing the Annual Full Capacity Deliverability Option.

ISO Response:

BTM expansion projects are not eligible for seeking Full Capacity Deliverability Status through the Annual Full Capacity (AFC) process. Allowing a BTM expansion project to go through the AFC Deliverability assessment would imply that the total output of the plant could exceed the originally studied Pmax. The BTM expansion process was designed to be relatively quick to implement, and as such does not allow for additional Network Upgrades. In order to meet these goals, the total output of the original project plus the BTM expansion project are capped at the original project's Pmax value while performing the reliability assessment. Thus the added capacity is not studied for reliability impacts in the same manner as other capacity additions on the system. Due to the limited nature of BTM studies the BTM expansion capacity cannot be increased without further reliability studies and the AFC Deliverability assessment cannot be used to increase the deliverability of the overall project.

Southern California Edison Company (SCE) –

In comments submitted on December 6, 2013, in response to the initial IPE Revised Straw Proposal on this topic, SCE stated its general agreement with the CAISO on refinements proposed up to that point in time regarding the ISP. SCE reaffirms its general support of the CAISO's proposed enhancements to improve the ISP. As an active participant in the ISP working group which helped develop the proposed ISP enhancements, SCE believes the latest proposal is generally a workable solution to address the major shortcomings of the current ISP process. However, SCE provides comments below in areas where it believes that further refinements are needed.

- Criteria for ISP eligibility: SCE has no further comment.

- Process and timeline enhancements: SCE concurs that if a combined System Impact Study (SIS) / Facility Study (FAC) agreement is executed, there is a significant savings in the time required to evaluate a project, and 120 calendar days should be sufficient time to complete both studies. However, 120 calendar days might not be sufficient time if the two studies are performed separately.
  If an Interconnection Customer (IC) seeking an ISP Interconnection, requests an SIS in order to assess its Interconnection Request (IR) before moving forward with an FAC, then it is necessary to identify the study duration for each of the studies. SCE proposes that the time allowed to perform the SIS be 90 calendar days and the duration to perform the FAC be 60-90 calendar days.

  Further, SCE appreciates the ISO including in the revised straw proposal the requirement proposed by SCE that the IC shall have no more than 90 calendar days to execute an Energy-Only GIA and that deferral of such time requirement is not allowed for a generating project studied through the ISP. Additionally, the ISO's willingness to clarify that an Energy-Only GIA will be amended when and if Full Deliverability studies are completed is helpful.

  ISO Response:

  ISP projects will be required to execute a combined System Impact Study (SIS) / Facility Study (FAC) agreement. This will be consistent with the intent of ISP to expedite the interconnection study.

- Tests for electrical independence. SCE has no further comment.
- Clarification on behind-the-meter ("BTM") expansion and its impact on net qualifying capacity "NQC"). SCE recommends that it be a requirement for BTM expansions that the expanded capacity be owned by the owning entity of the original generating facility (with a single Tax ID); and that the expansion could not be sold to a separate entity nor treated as a separate distinct project due to retail metering issues. In the event that the BTM expansion is for the purpose of sharing a generation tie-line, the configuration of mutual parties must be such that the Retail Service Provider's current Rules for Retail Metering are met. If there is a separate owner proposing the expansion, it is really a separate project and not an expansion of the original facilities. In such instances, the proposed project should be studied through the cluster interconnection process.

  ISO Response:

  The ISO agrees that BTM expansions are not eligible for separate ownership. With the joint operating constraints on the original plus expanded capacity being tied together, separate ownership could pose conflicting interests between separate owners and ISO Settlements does not allow this type of meter configuration with multiple owners. Moreover, different ownership could pose opportunities to bypass the standard interconnection processes that the BTM process was not intended to facilitate. The ISO believes that this issue can be addressed through the BPM process.

Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities) –

The Six Cities have no comments on the ISO's revised straw proposal for this topic at this time.

Large-scale Solar Association (LSA) –

LSA's comments on this issue are limited to the last topic listed above - Clarification on BTM expansion and its impact on NQC).

Enforcement of maximum output requirement

The Straw Proposal is somewhat confusing, as it simultaneously removes a requirement that BTM capacity be connected to a separate breaker but then imposes a requirement for an "automatic generation tripping scheme," which seems to be the same thing. During the stakeholder conference call about this element, the CAISO seemed to clarify that it would still require a plan from the developer to ensure that the combined maximum output of the original and BTM capacity would not exceed the Pmax of the original project, but that this assurance could be provided in another manner besides an automatic trip of the BTM capacity.

LSA supports additional flexibility in enforcing the maximum output limitation and requests that the CAISO clarify its intent more explicitly in the next proposal version.

ISO Response:

The ISO proposes to require an automatic generation tripping scheme as a means to guarantee that the total output of the plant never exceeds the originally studied Pmax. Further, the ISO proposes to allow the developer to choose how to implement this requirement; specifically, whether the tripping scheme is installed at the main plant breaker or at a separate breaker specific to the expansion capacity. Regardless, either option must ensure that total output of the plant never exceeds the originally studied Pmax. If the developer chooses not to connect the BTM expansion on a separate breaker, the automatic tripping scheme will have to trip the entire plant. Since in some cases it may not be practical to add a separate breaker for certain expansions, the ISO intends to eliminate the mandatory requirement for a separate breaker and give this choice to developers.

<u>Deliverability of existing facility</u>

LSA is very pleased to see that the CAISO has accepted LSA's prior comments and decided that the original project can retain its deliverability status after a BTM capacity addition, with the additional CAISO requirement that the BTM capacity be separately metered and have a separate Resource ID (i.e., be separately scheduled and settled).

However, LSA asks the CAISO to also be open to arrangements where BTM capacity is not separately metered but where the original project retains its deliverability status, with an NQC limit based on the deliverability for which the project was studied. For example, if a 100 MW solar project was studied at 85 MW in the Deliverability Assessment, a BTM capacity addition could safely be made without separate metering/scheduling as long as the maximum output is limited to the original 100 MW Pmax and the Qualifying Capacity does not exceed 85 MW.

ISO Response:

In order for the original project to preserve its deliverability status, the BTM expansion needs to have a separate resource ID and needs to be separately metered. Separately metered data by generator technology is required for forecasting purpose as well as for qualifying capacity calculations.

If the BTM expansion uses the same technology as the original project, then it may choose to interconnect without being metered separately, but the deliverability status of the entire project will then change from FCDS to PCDS. The requirement for the automatic tripping scheme, will still apply. The BTM capacity will not act as a basis under the CAISO Tariff to increase the Net Qualifying Capacity of the Generating Facility beyond the rating which pre-existed the Interconnection Request. We have included this clarification in section 4.1.4.4 of the revised proposal.

<u>Deliverability of BTM capacity</u>

If the BTM capacity is separately metered and scheduled, LSA sees no reason why it cannot apply separately for deliverability under the annual Deliverability Study option. If (as LSA recommends above as an option) the BTM capacity is not separately metered/scheduled, the project should be allowed to apply to increase its NQC from the level studied before to a level that would award deliverability to the BTM capacity.

ISO Response:

BTM expansion projects are not eligible for seeking Full Capacity Deliverability Status through the Annual Full Capacity (AFC) process. Allowing a BTM expansion project to go through the AFC Deliverability assessment would imply that the total output of the plant could exceed the originally studied Pmax. The BTM expansion process was designed to be relatively quick to implement, and as such does not allow for additional Network Upgrades. In order to meet these goals, the total output of the original project plus the BTM expansion project are capped at the original project's Pmax value while performing the reliability assessment. Thus, the added capacity is not studied for reliability impacts in the same manner as other capacity additions on the system. Due to the limited nature of BTM studies the BTM expansion capacity cannot be increased without further reliability studies and the AFC Deliverability assessment cannot be used to increase the deliverability of the overall project.

A BTM expansion cannot be counted towards an increase in the NQC of the original project because the original project has been granted deliverability "status" based on certain assumptions some of which are based on the size of a project. The deliverability assessment does not grant discrete "MW" of deliverability. It only grants a deliverability "status" for the entire project. No additional capacity can be counted towards an NQC increase unless it is studied for both deliverability and reliability. Therefore, if a developer wishes to expand its project in order to increase the NQC of its project, it should utilize the tariff mechanisms which include these comprehensive assessments (e.g., the cluster or non-BTM ISP study tracks).

<u>MMA requests</u>

LSA is puzzled by the Straw Proposal statement, and stakeholder conference call discussion, regarding the ability of developers to request BTM capacity additions through the MMA process, with use of the ISP required if there are any indications that a Network Upgrade (NU) of some kind might be needed.

First, this conclusion is contrary to CAISO statements in the Generation Interconnection Process Phase 2 (GIP-2) initiative where the BTM process was established, and contrary to statements of CAISO representatives in private meetings with developers that took place only recently.

Second, there is no apparent reason for the CAISO to take such a position. For example, the two possible issues of concern mentioned by SCE on the conference call – short-circuit duty (SCD) and Special Protection Schemes (SPSs) do not justify this position.

- The CAISO and PTOs already look at SCD concerns when assessing MMA requests today, so this is not a reason to reject the MMA approach.
- The CAISO and PTOs could easily check on whether the generation capacity limits for any SPS applicable to the existing project would be exceeded through the addition of the BTM capacity. Moreover, as pointed out by CalWEA on the conference call, since the combined output of the original and BTM capacity cannot exceed the level

studied for the original project, placing the SPS trip on the main breaker (to interrupt the capacity operating for both projects at that time) would not trip any more capacity than the Pmax of the original project.

Finally, if the MMA identifies any concerns at all – related to SCD, SPS, or in any other area where the CAISO or PTO are uncomfortable approving the request – then the request could be determined to be potential material and can then be processed through the regular interconnection-study process. The CAISO and PTO have complete discretion to make this determination, and this more rational approach would be far preferable to a blanket prohibition on use of MMA requests for BTM capacity additions.

ISO Response:

In ISO's response to stakeholder comments received on December 6, 2013, it was mentioned that "MMA is not intended to be used for adding capacity. Such expansions have to go through BTM expansion process". The ISO would like to clarify that this comment was intended for expansion at the existing generation facilities which have already achieved COD. Pursuant to CAISO tariff, Appendix DD, section 4.2.1.2(i)(2) "The behind-the-meter capacity expansion shall not take place until after the original Generating Facility has achieved Commercial Operation and all Reliability Network Upgrades for the original Generating Facility have been placed in service." Once a facility has gone into commercial operation it ceases to be involved with the interconnections process and the MMA process no longer applies.

It is not the intention of IPE Topic 4 to modify the existing MMA process as set forth in the ISO tariff.

Frontier Renewables (Frontier) –

Frontier's comments on this issue are limited to the last topic listed above - Clarification on BTM expansion and its impact on NQC. Frontier's comments cover three elements of the CAISO's BTM proposals – deliverability of the original facility, deliverability of the BTM capacity, and (of greatest concern) the ability to submit BTM addition requests through a Material Modification Assessment (MMA) request.

Frontier is considering addition of BTM capacity to one or more of its generation projects under development. Frontier has conducted extensive analysis of the potential for such capacity additions and met with CAISO executive management on November 26, 2013 to discuss this specific topic.

The CAISO representatives were very positive about the possibility of Frontier making this modification, and the discussion about the process for doing so was quite constructive. Frontier has been looking forward to working with the CAISO further and wants to ensure that the CAISO's implementation rules support such capacity additions, and are not modified to impede them.

<u>Deliverability of existing facility</u>

Frontier is very pleased to see that the CAISO has decided that the original project can retain its deliverability status after a BTM capacity addition, with the additional CAISO requirement that the BTM capacity be separately metered and have a separate Resource ID (i.e., be separately scheduled and settled).

However, Frontier has several concerns about this approach.

Frontier does not understand why production from the BTM capacity cannot be used to increase the NQC of the original project, as long as the original Pmax is not exceeded and the NQC is limited to the level that the original project was studied for. For example, if a project owner made an investment to increase the efficiency of the existing equipment such that the project's production increased in the hours when QC is calculated, the resulting higher NQC would apply (again, up to the level that the original project was studied for).

The fact that the additional project output in those hours comes from, e.g., energy previously produced by the project and stored using equipment installed under BTM provisions would not change the CAISO's ability to depend on the project overall to support load for Resource Adequacy purposes. If the tariff language for BTM additions does not support this concept, then the CAISO should request amendments that would.

This NQC enhancement should be available regardless of whether the BTM capacity is separately metered or not. If the project is separately metered, the CAISO can total the output of the two meters for purposes of calculating the overall QC. The CAISO should not care which part of the project is providing the energy during the applicable hours.

Finally, consistent with this position, Frontier believes that separate metering of the BTM capacity should be an option and not a requirement.

ISO Response:

Please refer to the response to LSA above under the "Deliverability for BTM Capacity" heading.

<u>MMA requests</u>

Frontier is surprised by the Straw Proposal statement, and stakeholder conference call discussion, regarding the ability of developers to request BTM capacity additions through the MMA process, with submission of a separate Interconnection Request (IR) and use of the ISP required only if there are any indications that a Network Upgrade (NU) of some kind might be needed. Frontier is concerned for the following reasons:

- Frontier was aware of the CAISO's statements in the GIP-2 process that BTM capacity additions could be proposed through the MMA process, and it sought and received explicit confirmation at the meeting with CAISO executive management referenced above.

- During the meeting discussed above, the CAISO stated that the MMA process could be used for the contemplated BTM addition; in fact, the CAISO provided specific guidance for the contents of the MMA request, i.e., that the request should include details about the equipment, PSLF model, and protection schemes to limit Pmax to the studied output level.

Frontier asks the CAISO to confirm our understanding of the process. If any concerns are identified during the MMA analysis, the request would be determined to be potentially material, and it can then proceed through the regular interconnection-study process. This would allow projects with straightforward, no impact BTM additions to proceed through the MMA process rather than the costly and lengthy Independent Study Process.

If the ISP process is made a blanket requirement for BTM additions, which would both strengthen and stabilize the CAISO controlled grid as more renewable generators come online to meet state-mandated targets, that would severely discourage developers from pursuing them. In addition to the cost and time requirements generally, for practical purposes the requirement for a new IR (even if processed through the ISP) would jeopardize a project's ability to capture the Federal Investment Tax Credit that minimizes the cost burden to ratepayers.

ISO Response:

Please see the response to LSA above under the "MMA Requests" heading.

4.1.3 Proposed modifications to February 5 revised straw proposal

Based on stakeholder comments, the working group proposes to retain, without modification, the enhancements proposed in the February 5 revised straw proposal for two of the four areas listed previously in section 4.1.1 :

- Criteria for ISP eligibility
- Test for electrical independence

However, after a consideration of the stakeholder input received, the ISO is proposing modifications to the two of the four areas:

- Process and timeline enhancements
- Clarification on BTM expansion and its impact on NQC

A requirement to sign a combined study agreement for System Impact Study (SIS) and Facilities Study has been added the ISP timeline under section 4.1.4.2. In the original proposed timeline, 120 calendar days were provided for completion of System Impact Study (SIS) and Facilities Study after the execution of an ISP study agreement. This combined study agreement is consistent with the intent of ISP to provide a shorter timeline for interconnection. For clarity, a complete draft final straw proposal is presented in the following section.

A clarification about requirement of separate metering and a new resource ID for the BTM expansion is added to section 4.1.4.4.

4.1.4 Draft final proposal

4.1.4.1 Criteria for ISP eligibility

Under the existing tariff, an interconnection customer that wishes to utilize the ISP must show that its desired COD is physically and commercially achievable by demonstrating that it satisfies at least two of the following criteria:

1. The interconnection customer has obtained, or has demonstrated the ability to obtain, all regulatory approvals and permits needed to complete construction in time to meet the generating facility's requested COD.
2. The interconnection customer is able to provide, or has demonstrated the ability to obtain, a purchase order for generating equipment specific to the proposed generating facility, or a statement signed by an officer or authorized agent of the interconnection customer demonstrating that the interconnection customer has a commitment for the supply of its major generating equipment in time to meet the COD through a purchase agreement to which the interconnection customer is a party.
3. The interconnection customer can provide reasonable evidence of adequate financing or other financial resources necessary to make the required interconnection financial security postings.[13]

The ISP working group recommends that all three criteria listed above must be satisfied (rather than only two of the criteria as under the existing tariff) and that the following two additional criteria must also be satisfied as part of the initial screening/validation process under the ISP:

4. The proposed POI cannot require any expansion, except for those upgrades already planned, and that will be in service by the time the proposed COD of the ISP project. The specific criteria are; the proposed point of interconnection must be to an existing facility on the ISO controlled grid or a transmission upgrade approved in the ISO transmission planning process (TPP) that has completed the permitting process and is currently under construction. The existing facility where the point of interconnection is proposed to be located must be able to accommodate the interconnection of the ISP project without requiring any expansion of the existing facility. The most updated

[13] ISO tariff appendix DD, section 4.1.1.

expected in-service date of any upgrade required to accommodate the proposed point of interconnection must be able to meet the proposed COD of the ISP project.

5. There is no network upgrade that is already part of an existing GIP/GIDAP or TPP plan, or that is known to the ISO or PTO through a study that is currently underway, that is needed to allow the project to reliably enter into commercial operation, is yet to be operational, and has a completion date that is later than the ISP's requested COD or is not yet fully permitted and currently under construction.

The proposed requirement to satisfy all five of these criteria is intended to provide greater assurances that projects seeking to exercise the option to be studied under the ISP truly have a need for this option rather than the standard interconnection process, have the ability to perform under this option, and the project's requested COD is achievable based on the requested point of interconnection and any network upgrades expected to be needed for the customer's project.

4.1.4.2 Process and timeline enhancements

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

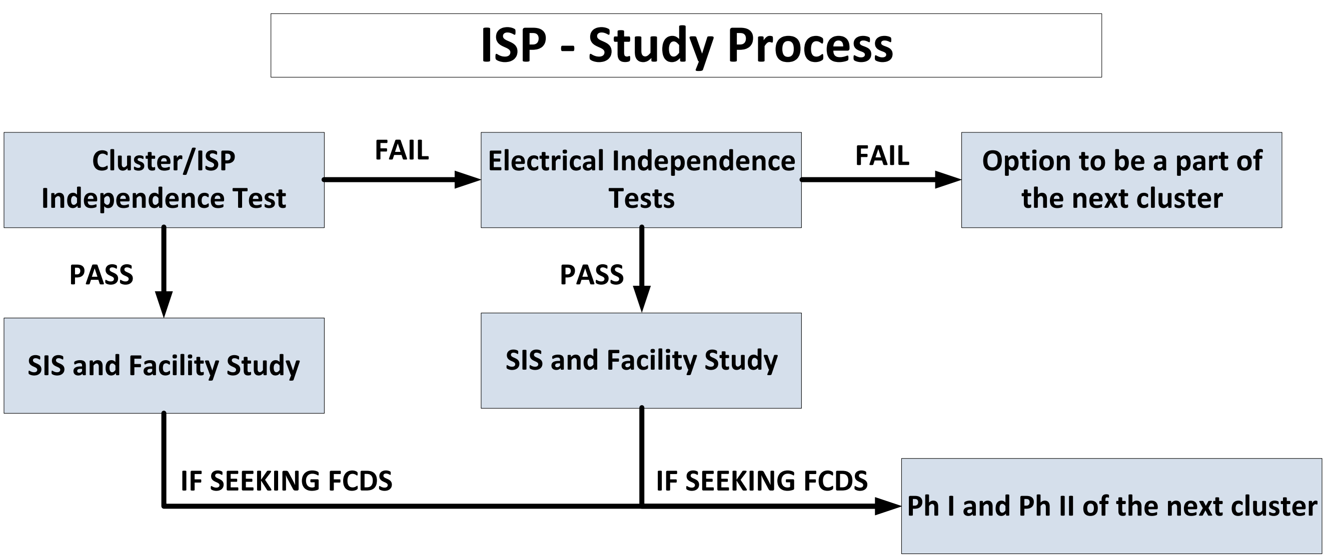
1. Cluster/ISP independence test – The working group recommends that an ISP project should be given an opportunity to go directly into a system impact study (SIS) if there are no other cluster projects or ISP projects under study in the study area, as defined in the current cluster study where the ISP project is seeking interconnection. If there are no other cluster projects that have yet to complete the phase II interconnection study process or other ISP projects that have yet to complete the SIS in the same cluster study area as the ISP project, then the ISP project will pass this test and will move forward with an SIS and a facilities study without having to satisfy the electrical independence test. After the SIS and facilities study are completed, the project will be eligible to start generator interconnection agreement (GIA) negotiations as an energy-only (EO) project.

2. Tests for electrical independence – If the ISP project is in a study area which has projects that have yet to complete the phase II interconnection study process or a SIS and thus fails the cluster/ISP independence test described above, then the phase I interconnection study results for the current cluster (*i.e.*, the last cluster which opened up before the ISP request was received) and/or SIS results of any previous ISP project in the same study area will be used to assess the electrical independence of the ISP project. If the ISP project passes all the tests for electrical independence (discussed below), then an SIS and facilities study will be performed. After the SIS and facilities study are completed, the ISP project will be eligible to start GIA negotiations as an EO project.

3. If the ISP project has requested FCDS or partial capacity deliverability status (PCDS), it will be studied for deliverability as part of the phase I and phase II interconnection studies for the next cluster (Next cluster refers to the cluster study performed for the queue cluster window that opens after the ISP FCDS request is received).
4. If an ISP project fails to satisfy any of the tests for electrical independence, it will be given an option to be part of the next cluster (Next cluster refers to the cluster study performed for the queue cluster window that opens after the ISP FCDS request is received) study or to withdraw.
5. A project requesting to participate in the ISP and seeking FCDS or PCDS will by default be an "Option A" project under the GIDAP and not be allowed to elect "Option B".
6. A project consisting of asynchronous generators that requests to participate in the ISP must provide 0.95 (lead/lag) power factor at the point of interconnection.
7. Following the completion of the SIS and facilities studies the ISO, Participating TO and interconnection customer shall meet the tariff timelines for GIA tendering, negotiation and execution of an Energy Only GIA consistent with Appendix D, Section 13. A deferral of such time requirement is not allowed for an ISP project. EO GIA will be amended to reflect Full Deliverability Study results whenever such studies are completed**.**

A simplified process flow diagram for a project in this improved ISP is provided in Figure 2:

Figure 2 – Proposed Process Enhancement to ISP



The following timeline is proposed for completing the SIS and facilities study:

- 30 calendar days to perform interconnection request validation and ISP eligibility screening
- 30 calendar days to perform the tests for electrical independence, once the necessary data becomes available (see below)
- 120 calendar days to complete the SIS and facilities study after the execution of an ISP Study Agreement (a combined study agreement needs to be signed by a project that wishes to participate in the ISP)

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

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

Consider the following examples to further illustrate the process timeline.

Example 1: Consider an ISP request that is received in May 2014. If it passes the cluster/ISP independence test, then an SIS and facilities study will be performed using the latest available cluster base case and the ISP project will be eligible to interconnect as an EO project after signing its EO GIA, as early as Q4 of 2014. If the ISP project is seeking FCDS or PCDS, then it will be studied as an option A project as part of the next cluster (cluster 8) to receive its phase II interconnection study results as early as Q4 of 2016 and transmission plan deliverability (TPD) allocation as early as Q2 of 2017.

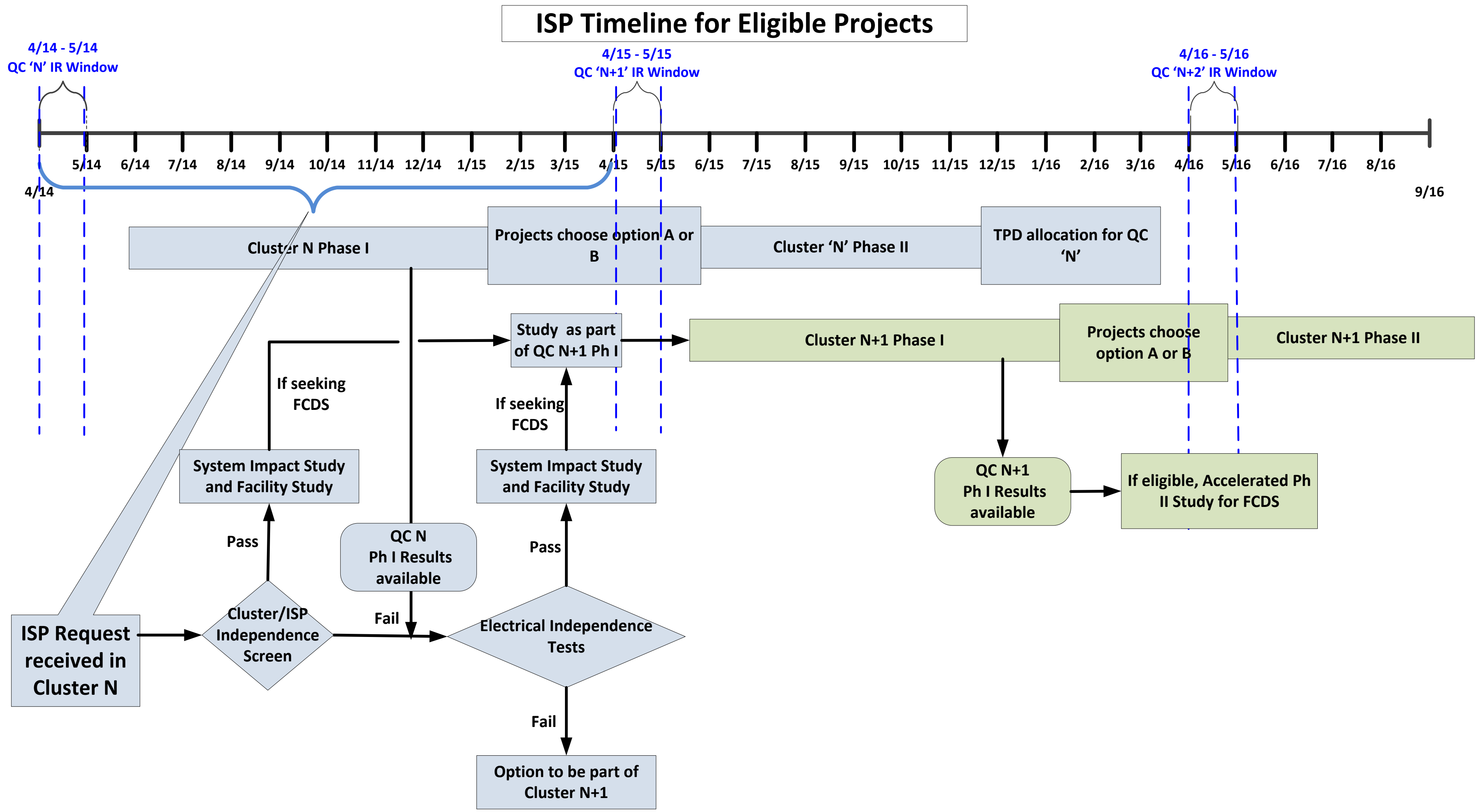
By comparison, under the existing process, an ISP request received in May 2014 will be tested for independence after the phase II interconnection study results for the current cluster (cluster 7) become available in Q4 of 2015. If the ISP project passes the tests, then an SIS and facilities study will be performed, after which the ISP project can potentially interconnect as an EO project. If the ISP project is seeking FCDS or PCDS, it will be studied as part of the phase II interconnection study for the next cluster (cluster 8) in Q4 of 2016 and will receive its TPD allocation in Q2 of 2017.

Example 2: Consider an ISP request that is received in May 2014. If it fails the cluster/ISP independence test, then the tests for electrical independence will be performed using the phase I interconnection study results for the current cluster (cluster 7) in Q1 of 2015. If the ISP project passes the tests for electrical independence, then an SIS and facilities study will be performed using the latest available cluster base case and the ISP project will be eligible to interconnect as an EO project after signing its EO GIA, as early as Q1 of 2015. If the ISP project is seeking FCDS or PCDS, then it will be studied as an option A project as part of the next cluster (cluster 8) to receive its phase II interconnection study results as early as Q4 of 2016 and TPD allocation as early as Q2 of 2017.

By comparison, under the existing process, an ISP request received in May 2014 will be tested for independence after the phase II interconnection study results for the current cluster become available in Q4 of 2015. If the ISP project passes the tests, then an SIS and facilities study will be performed, after which the ISP project can potentially interconnect as an EO project. If ISP the project is seeking FCDS or PCDS, it will be studied as part of the phase II interconnection study for the next cluster in Q4 of 2016 and will receive its TPD allocation in Q2 of 2017.

Figure 3 illustrates the ISP timeline as enhanced by these proposals.

Figure 3 – Proposed ISP Timeline Enhancement



4.1.4.3 Tests for electrical independence

The ISP timeline is dependent on the timing of the tests for electrical independence. The existing tariff specifies that the electrical independence of a project submitted under the ISP needs to be tested based on the base case that is being used for the most recent queue cluster. Also, under the existing flow impact test, if the current queue cluster studies or earlier-queued ISP studies have not yet determined which transmission facilities are electrically impacted by the generating facility being tested require network upgrades, and the ISO cannot reasonably anticipate whether such transmission facilities will require network upgrades from other data, then the ISO will wait to conduct the independence analysis until sufficient information exists in order to make this determination.[14] This existing process can introduce delays and uncertainties in the commencement of tests for electrical independence. The ISO is therefore proposing to use the phase I interconnection study results of the current cluster to test for electrical independence.

The existing flow impact test against network upgrades does not delineate between reliability network upgrades (RNUs) and deliverability network upgrades (DNUs), and the ISO's practice has been to test against both. Testing for electrical independence based on DNUs is not required since a project requesting FCDS will go through a separate deliverability assessment.

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

The following discussion and Figure 4 summarize the proposed changes to the tests for electrical independence:

a. Flow impact test:

   i. The flow impact will only be tested on RNUs where the need for the RNUs was related to flow concerns. Testing area delivery network upgrades (ADNUs) and local delivery network upgrades (LDNUs) for independence creates unnecessary hurdles to the interconnection of ISP projects as EO resources. Due to the nature of RNUs, it is expected that the flow impact test will seldom be required since RNUs are rarely related to flow concerns. If an RNU is related to flow concerns, the flow impact will be tested on the limiting elements that drive the need for RNUs. Flow impact on system protection scheme (SPS) RNUs will not be tested.

b. Short circuit test:

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[14] ISO tariff appendix DD, sections 4.2, 4.2.1.1(i).

i. Under the existing tariff, an ISP project will pass the short circuit test if its short circuit contribution is less than 100 amperes.[15] This 100-ampere threshold can be too restrictive in certain areas and does not serve the intent of testing electrical dependence across a diverse topology. The working group recommends using a proportional threshold instead of an absolute threshold, as follows:

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

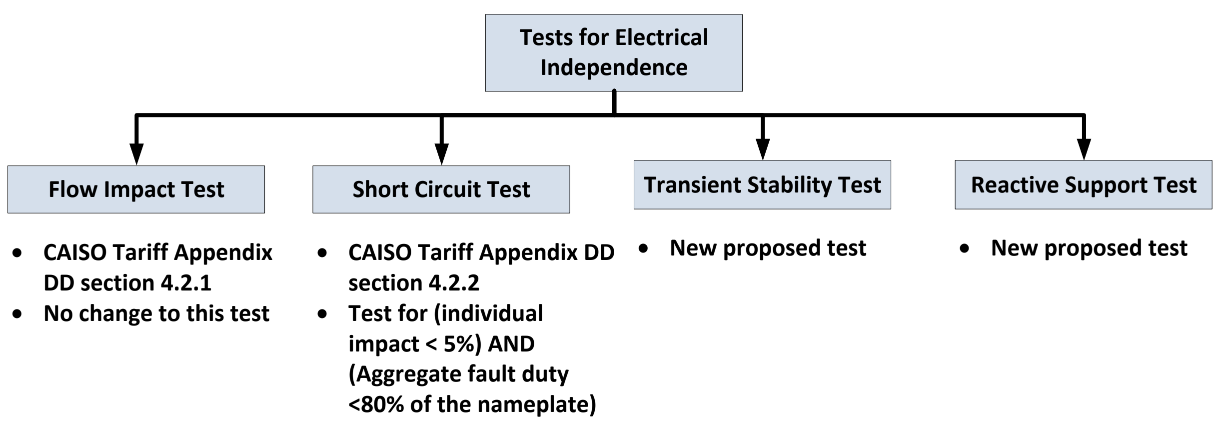
c. Transient stability test:

The working group proposes a new component of the tests for electrical independence test: if an ISP project is connecting in an area where transient stability issues are identified in the current cluster, then the project will fail the transient stability test.

d. Reactive support test:

The working group proposes a new component of the tests for electrical independence: if an ISP project is connecting in an area where reactive support needs are identified as RNUs in the current cluster, then the project will fail the reactive support test.

Figure 4 – Proposed Tests for Electrical Independence



Failure to pass the tests for electrical independence: If an ISP project fails any of the tests for electrical independence, the interconnection customer will be notified and given the option to participate in the next cluster as a non-ISP project.

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[15] ISO tariff appendix DD, section 4.2.2.

4.1.4.4 Clarification on BTM expansion and its impact on the NQC

The working group proposes the following modifications/clarifications to the existing tariff section regarding the technical and business criteria that must be satisfied for study in the ISP of BTM expansion.[16] Note that although the ISO is presenting this information in the form of draft changes to its existing tariff language, the ISO is doing so only for ease of stakeholder review. The ISO will conduct a tariff stakeholder process for this and other IPE proposals in which the specific tariff language may be revised as necessary in order to best reflect the final proposal. Therefore, stakeholders are encouraged to provide general comments at this time in lieu of specific suggested edits to the tariff language.

1. Size of the expansion

The working group proposes clarifying the technical criteria regarding the size limits on the BTM expansion to read as follows:

> The total nameplate capacity of the existing Generating Facility plus the incremental increase in capacity does not exceed in the aggregate one hundred twenty-five (125) percent of the capacity studied for the project's initial interconnection request, before any BTM expansion, and the incremental increase in capacity ~~and~~ does not exceed, in the aggregate <u>including any prior expansions implemented pursuant to this section</u>, one hundred (100) MW.[17]

2. Requirement for a separate expansion breaker

The existing technical criteria require that the expanded capacity for the generating facility be placed behind a separate breaker (the expansion breaker) such that the expansion can be metered separately at all times.[18] The working group recommends that this requirement be removed, because the BTM expansion is required to be behind the main gen-tie breaker for the existing generating facility.

3. Deliverability status of BTM expansion and its impact on NQC

In order to eliminate confusion regarding the deliverability status of BTM expansion and the impact of BTM expansion on existing project's NQC, the working group proposes to modify and simplify BTM expansion process as follows:

- The existing generating facility will maintain the deliverability status (FCDS or EO) which existed before the BTM interconnection request.

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[16] ISO tariff appendix DD, section 4.2.1.2.

[17] ISO tariff appendix DD, section 4.2.1.2(i)(1).

[18] ISO tariff appendix DD, section 4.2.1.2(i)(3).

- The new BTM capacity will have EO status. The expanded capacity will have to be metered separately at all times and will have a new resource ID. If the BTM expansion project uses the same technology as the original project, then the interconnection customer may choose to add the BTM capacity without being metered separately, but the deliverability status of the entire project will then change from FCDS to PCDS. The requirement for the automatic tripping scheme mentioned below will still apply to this project. The BTM capacity will not act as a basis under the CAISO Tariff to increase the Net Qualifying Capacity of the Generating Facility beyond the rating which pre-existed the BTM expansion Request.
- The interconnection customer will have to install an automatic generator tripping scheme to trip sufficient generation to ensure that the total output of the existing generating facility and the expansion facility does not exceed, at any time, the capacity studied in the project's initial interconnection request, before any BTM expansion.
- If the project considering BTM expansion desires to have FCDS with respect to its requested capacity expansion, then it should not proceed through the BTM expansion process. Instead, it should go through the ISP or cluster study process.

4.2 Topic 5 – Improve Fast Track

The purpose of this topic is to develop Fast Track (FT) screening criteria based on appropriate criteria for projects seeking FT treatment to interconnect to the ISO's higher voltage networked transmission system. The screening criteria will be developed consistent with direction provided by FERC in its Order 792,[19] which was issued on November 22, 2013, *i.e.*, after the issuance of the November 8 straw proposal. While clarification of the general tariff process is within the scope of this topic, the current 5 MW FT project size limitation will not be considered for revision.[20] The tariff revisions to improve the FT process will be made solely to the GIDAP, because all new requests by customers to take part in the FT process will be pursuant to the GIDAP.

4.2.1 FT working group

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

[19] *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013) (Order 792).

[20] *See* ISO tariff appendix DD, section 5.1.

from the generation development community with both technical and policy expertise participated in the working group.

The working group held its first meeting on August 12, 2013 and has been generally meeting bi-weekly in an effort to develop a final proposal that can be vetted with the broader IPE stakeholder group.

4.2.2 February 5 revised straw proposal

The ISO's revised straw proposal from the February 5 paper is presented in the table below. The purpose of the proposed enhancements was to further clarify the intent of the screens and the customer option meeting for the FT study process.

Table 3 – Revised straw proposal to improve the FT process

Appendix DD-Section No.	Appendix DD-Subsection No.	Current Tariff Language	Proposed Tariff Language
5.1, 3rd Paragraph.		Initiating the Fast Track Interconnection Request. To initiate an Interconnection Request under the Fast Track Process, and have the Interconnection Request considered for validation the Interconnection Customer must provide the CAISO with: (i) a completed Interconnection Request as set forth in Appendix 1 ; (ii) a non-refundable processing fee of \$500 and a study deposit of \$1,000; and	Initiating the Fast Track Interconnection Request. To initiate an Interconnection Request under the Fast Track Process, and have the Interconnection Request considered for validation the Interconnection Customer must provide the CAISO with: (i) a completed Interconnection Request as set forth in Appendix 1 ; (ii) a non-refundable processing fee of ***\$1000*** and a study deposit of ***\$25,000***; Discussion of Changes The work group has proposed some significant changes to the screening process. These changes will help further clarify the intent and the application of the screens. However, this does impact the amount of work and data required for the screening process. The proposed fees should address the additional workload required for the proposed screening process.
5.2		Within fifteen (15) Business Days after the CAISO notifies the Interconnection Customer that the Interconnection Request is deemed complete, valid, and ready to be studied, the applicable Participating TO shall perform an initial review using the screens set forth in Section 5.3 below, shall notify the	Within ***Thirty (30) Business Days*** after the CAISO notifies the Interconnection Customer that the Interconnection Request is deemed complete, valid, and ready to be studied, the applicable Participating TO shall perform an initial review using the screens set forth in Section 5.3 below, shall notify the

Table 3 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
		Interconnection Customer of the results, and shall include with the notification copies of the analysis and data underlying the Participating TO's determinations under the screens.	Interconnection Customer of the results, ***in a report that provides the details*** of the **initial review** ~~analysis~~ and data underlying the Participating TO's determinations using the screens. Discussion of Changes The group is proposing to increase the time required to perform the initial screening from 15 to 30 Business days. This will ensure that the ISO and PTO have enough time to screen the fast track project for any potential issues. The group is also proposing to issue a report that will provide the details around the application of the screens.
5.3	**5.3.1.2**	For interconnection of a proposed Generating Facility to a radial transmission circuit, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation. For purposes of this Section 5.3.1.2, a line section shall be considered as that portion of a Participating TO's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the transmission line.	For interconnection of a proposed Generating Facility to a radial transmission circuit **under CAISO control**, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation. For purposes of this Section 5.3.1.2, a line section shall be considered as that portion of a PTO's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the transmission line. ***This screen will not be required for a proposed interconnection of a Generating Facility to a radial line with no load.*** ***In cases where the circuit lacks the telemetry needed to provide the annual peak load measurement data, power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen.*** Discussion of Changes The proposal to use the latest Generation interconnection Phase I/ Phase II study base case eliminates the confusion about the type of base case needed for the

Table 3 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
			analysis.
Proposed Additional Screens			
	5.3.X1	None	The proposed Generating Facility must interconnect to an existing substation. The proposed interconnection: • Shall be subject to availability of vacant switch rack position.~~,~~ • Taps to an existing transmission line shall not be acceptable and the project will fail the screen. **Discussion of Changes** **The telecommunication requirement, as specified in the November 8 straw proposal, could not be determined until the completion of the facility study. The screen was updated to address the issue.**
	5.3.X3	None	The proposed Generating Facility, in the aggregate with other Generating Facilities interconnected to the same transmission circuit on an existing substation, shall not cause the Power flow on any CAISO-controlled facility to increase by 5 percent, and shall not exceed 80 percent of the same facility's normal rating. Power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen. **Discussion of Changes** **This screen was further modified to ensure that the proposed FT interconnection is on an existing substation. The screen addresses the scope of application to all the CAISO controlled facilities.**
5.3.3.		If the proposed interconnection fails the screens and no Upgrades are reasonably anticipated, but the CAISO and Participating TO determine that the Generating Facility may nevertheless be	If the proposed interconnection fails the screens ***then, in accordance with section 5.2, the ISO and applicable Participating TO will provide the Interconnection Customer with copies of all data and***

Table 3 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
		interconnected consistent with safety, reliability, and power quality standards under these procedures, the Participating TO shall, within Fifteen (15) Business Days, provide the Interconnection Customer with a Small Generator Interconnection Agreement for execution.	***initial review documentation*** ~~***analyses***~~ ***underlying this conclusion. Also, in accordance with section 5.4, the ISO and Applicable Participating TO will offer to convene a Results meeting***. Discussion of Changes It was hard for the group to think of a potential scenario that fits the situation described in this provision. The proposed language better addresses the consequences of failing the screens.
5.4		Customer Options Meeting	Change the name to **Results meeting**.
	5.5.1	Within ten (10) Business Days following receipt of the deposit for a supplemental review, the CAISO and Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably.	Within **Ninety (90)** ~~**Fifteen (15)**~~Business Days following receipt of the deposit for a supplemental review, the CAISO and Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably. ***If a Generating Facility has passed the screens set forth in Section 5.3, the ISO and Applicable Participating TO shall perform a facilities study for that Generating Unit.*** Discussion of Changes The WG determined that to interconnect a FT project that passes the screens a facilities study will be needed to define the scope of the interconnection that will be reflected in the SGIA. The Supplemental Review section of the tariff does not specify the types of studies that would be offered to be performed when a FT project fails the screens. The WG considered defining the studies as being similar to system impact and facility study, and/or a hybrid of the two studies. While the tariff will not be changed to define the type of studies to be performed the timeline is proposed to be extended to **90** ~~**15**~~Business days to accommodate the type of studies envisioned.

4.2.3 Stakeholder comments

In the February 28 comments received, stakeholders did not provide specific comments on the revised straw proposal as presented above in Table 3. However, stakeholders did express general support for the ISO's proposed approach to comply with Order 792 and expressed interest in commenting on the associated proposed tariff language to comply with Order 792 as it is developed.

4.2.4 FERC Order 792

On November 22, 2013, FERC issued Order 792 directing revisions to FERC's *pro forma* small generator interconnection agreement (SGIA) and small generator interconnection procedures (SGIP). Order 792 requires transmission providers to implement, among others, the following SGIP/SGIA reforms:

- Provide prospective interconnection customers with the opportunity to request a pre-application report;[21]
- Apply new fast track interconnection eligibility thresholds;[22]
- Revise the customer options meeting and supplemental review process following failure of a fast track screen;[23]
- Permit interconnection customers to provide written comments on any required upgrades in the facilities study;[24]
- Account for the interconnection of storage devices under small generator interconnection procedures;[25]
- Revise the *pro forma* SGIP to require interconnection customers wishing to interconnect using Network Resource Interconnection Service to do so under the large generator interconnection procedures (LGIP) and execute a large generator interconnection agreement (LGIA).[26]

Order 792 requires each public utility transmission provider to submit a compliance filing within six months of the effective date of Order 792, *i.e.*, by August 3, 2014.[27] Order 792 states that, in cases

[21] Order 792 at PP 28-82.

[22] *Id.* at PP 83-111.

[23] *Id*. at PP 112-89.

[24] *Id*. at PP 190-210.

[25] *Id*. at PP 223-32.

[26] *Id*. at PP 233-37.

[27] *Id*. at P 269. Order 792 became effective on February 3, 2014. *See* 78 Fed. Reg. 73240 (Dec. 5, 2013).

where provisions in public utility transmission providers' existing SGIPs and SGIAs have previously been found by FERC to be consistent with or superior to the *pro forma* SGIP and SGIA, the public utility transmission providers must either comply with Order 792 or demonstrate that the previously approved provisions are consistent with or superior to the *pro forma* SGIP and SGIA as modified in Order 792.[28]

As the ISO will explain in its filing to comply with Order 792, the ISO believes that at least some provisions in its existing tariff already comply with or are superior to the Order 792 reforms. Of importance to any compliance filing is the fact that the ISO no longer has separate interconnection procedures for new interconnection requests by small generators. Instead, the ISO's interconnection procedures set forth in appendix DD of the ISO tariff apply to all new interconnection requests by both large and small generators. In the paragraphs below, the ISO sets forth a proposal to comply with the directives of Order 792. In comments, stakeholders have generally supported this approach or withheld comment pending release of draft tariff language to comply with Order 792.

4.2.4.1 Pre-application report process

Order 792 directed each public utility transmission provider to include tariff language regarding a pre-application report process that allows prospective interconnection customers to request a pre-application report.[29] The ISO proposes to incorporate certain language adopted by Order 792 governing the pre-application report process into appendix DD of the ISO tariff.[30] This language will seek to incorporate information categories identified in Order 792 that apply to a networked transmission system as opposed to a radial distribution circuit. The ISO proposes to specify in the tariff language that the pre-application report will only apply to developers considering the interconnection of resources no larger than 20 MW.

4.2.4.2 Fast track eligibility

In Order 792, FERC adopted fast track interconnection eligibility thresholds that (1) modify fast track eligibility for inverter-based machines based on individual system and generator characteristics; (2) limit eligibility for lines below 5 kV; and (3) make all projects interconnecting to lines greater than 69-kV ineligible for the fast track process.[31] Order 792 maintains a 2 MW eligibility threshold for both synchronous and induction machines.[32]

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[28] Order 792 at P 270.

[29] *Id.* at PP 28-82.

[30] *See* Order 792 appendix C, section 1.2.

[31] Order 792 at PP 102-07.

[32] *Id*. at P 106.

Appendix DD of the ISO's existing tariff (the GIDAP) provides that an interconnection customer may request interconnection of a proposed generating facility under the fast track process if the facility is no larger than 5 MW and is requesting energy-only deliverability status.[33] The tariff also requires that the interconnection customer's resource meet the codes, standards, and certification requirements of appendices 9 and 10 of appendix DD, or that the applicable participating transmission owner notify the ISO that it has reviewed the design for or tested the proposed resource and has determined that the proposed facility may interconnect consistent with reliability criteria and good utility practice.[34] Tariff appendix DD also permits an existing resource to take advantage of the fast track process if it is reconfiguring or repowering in a manner that increases the gross generating capacity by not more than 5 MW.[35] The ISO is not proposing any changes to its current fast track eligibility thresholds because these tariff provisions are more inclusive than the fast track eligibility thresholds adopted in Order 792. The ISO believes, therefore, that these thresholds are consistent with or superior to those adopted in Order 792.

4.2.4.3 Customer options meeting and supplemental review process

In Order 792, FERC adopted reforms to the customer options meeting and supplemental review process following an interconnection customer's failure of a fast track screen. These reforms require transmission providers to apply three supplemental screens to assess if a fast track interconnection process is still possible: (1) a minimum load screen; (2) a power quality and voltage screen; and (3) a safety and reliability screen.[36] The minimum load screen assesses if the aggregate generating capacity on a line section, including the proposed small generating facility, is less than 100 percent of minimum load.[37] A transmission provider need not perform the minimum load screen if data are unavailable or if it is unable to calculate, estimate, or determine minimum load.[38] Sections 2.4.4.2 and 2.4.4.3 in the *pro forma* SGIP language adopted by FERC in Order 792 describe the power quality and voltage as well as the safety and reliability screens.[39] Order 792 provides that the interconnection customer can select the order in which the transmission provider conducts the screens.[40] Under Order 792, an interconnection customer is responsible for the actual costs of conducting the supplemental review. The transmission provider must provide the

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33 ISO tariff appendix DD, section 5.1.

34 Appendix 9 identifies various standards and codes. Appendix 10 relates to certification of equipment packages.

35 ISO tariff appendix DD, section 5.1.

36 Order 792 at P 117.

37 *Id.* at PP 141-48.

38 *Id*. at P 144.

39 *Id.* at PP 156-61 and appendix C.

40 *Id.* at PP 164, 170-72.

interconnection customer with a good faith estimate of the cost to perform the supplemental review, and the interconnection customer must pay this amount as a deposit in advance of the supplemental review.[41]

As described above, in the February 5 revised straw proposal the ISO proposed refinements to both its fast track screens that comprise the initial review as well as the supplemental review, if an interconnection customer fails the fast track screens. As described in section 4.2.5 of this paper, the ISO is proposing to modify the fee and timeframes associated with the initial review under the fast track interconnection process. For fast track screens relying on the peak load on a radial transmission circuit, the ISO is proposing to modify the source of this data if no telemetry on the circuit exists and to eliminate this screen when no load on the circuit exists. The ISO is also proposing to eliminate an existing screen involving the interconnection of a proposed generating facility to the load side of spot network protectors. In connection with the ISO's screen involving the maximum fault current on the transmission circuit, the ISO is proposing to reduce the maximum threshold to ensure existing relay settings and coordination are not adversely affected due to the proposed resource interconnection. As part of another screen, the ISO is also proposing to reduce the threshold of the short circuit interrupting capability associated with the proposed resource interconnection and the ISO is proposing to modify an existing fast track screen to account for reliability limitations of existing transmission circuits. Finally, the ISO is proposing new screens relating to the need for the interconnection to occur at existing facilities and the need to not violate ISO voltage standards or increase power flows on a facility's circuit by more than 5 percent and exceed 80 percent of the facility's normal rating.

Order 792 also articulated specific processes to follow the supplemental review if (1) the proposed interconnection passes the supplemental review screens and does not require construction of facilities by the transmission provider on its own system; (2) the review identifies interconnection facilities or minor modifications to the transmission provider's system for the proposed interconnection to pass the supplemental review screens; and (3) the proposed interconnection requires more than interconnection facilities or minor modifications to the transmission provider's system to pass the supplemental review screens.[42] In the first circumstance, the proposed interconnection passes the supplemental review screens and the interconnection customer receives an interconnection agreement within ten business days. In the second circumstance, the proposed interconnection passes the supplemental review screens, and, if the interconnection customer agrees to pay for the modifications, the interconnection customer receives an interconnection agreement within 15 business days of receiving written notification of the supplemental review results. In both instances, the ISO believes further assessment will be

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[41] *Id*. at PP 170-72.

[42] *Id*. at PP 181-88.

necessary by the Participating TO to identify interconnection facilities. The ISO will propose language to accommodate that assessment, including the additional time to ensure the assessment is complete before providing the interconnection customer with an interconnection agreement. This assessment will ensure the interconnection customer only pays for the facilities needed to complete the interconnection in a safe and reliable manner. In the third circumstance, the proposed interconnection does not pass the supplemental review screens and must continue to be evaluated under the study process.

4.2.4.4 Opportunity to submit comments on any required upgrades in the facilities study

In Order 792 directed transmission providers to permit interconnection customers to provide written comments on any required upgrades in the facilities study.[43] The ISO tariff currently provides an opportunity for the interconnection customers to submit written comments on both the phase I and phase II interconnection study reports.[44] The ISO is not proposing any changes to this tariff language. The ISO believes its existing tariff is consistent with or superior to the directive adopted in Order 792. The ISO also plans to extend this right for an interconnection customer to submit written comments in response to a feasibility study performed as part of the independent study process.

4.2.4.5 Account for the interconnection of storage devices under small generator interconnection procedures

Order 792 directed transmission providers to specifically define electric storage devices as generating facilities that can take advantage of generator interconnection procedures.[45] Order 792 also directed that transmission providers should measure the capacity of a small generating facility based on the capacity specified in the interconnection request, which may be less than the maximum capacity that a device is capable of injecting into the transmission provider's system. The ISO plans to incorporate language into its tariff as directed in Order 792, into Appendix A of the ISO tariff. The ISO will also amend the definition of generating facility in appendices EE and FF, which contains the *pro forma* SGIA and LGIA subject to appendix DD.

4.2.4.6 Require interconnection customers wishing to interconnect using network resource interconnection service to do so under the LGIP and execute the LGIA

Order 792 directed each transmission provider to require an interconnection customer wishing to interconnect a small generating facility using network resource interconnection service to do so under the transmission provider's LGIP and to execute an LGIA.[46] As discussed above, the ISO has

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[43] Order 792 at PP 203-09.

[44] ISO tariff appendix DD, sections 6.7, 8.7.

[45] Order 792 at PP 227-31.

[46] *Id*. at PP 285-86.

consolidated its small and large generator interconnection procedures in tariff appendix DD. Also, section 2.4.2 of appendix DD allows an interconnection customer to connect its generating facility to the ISO grid and be eligible to deliver the resource's output using the available capacity of the ISO grid. The ISO is not proposing any changes to this language, and the ISO believes its existing tariff is consistent with or superior to the directive adopted in Order 792.

4.2.5 Draft final proposal

The ISO's final revised straw proposal is presented in the table below. This is a comprehensive proposal and captures all the changes that we have proposed in the process. Any updates to the screens, as reported in the February 5 revised straw proposal (see section 4.2.2 of this paper) are presented in red font and denoted with either underline for new language or strikeout for deletions. Two new sections (5.3.4 & 5.4.1) have been added to the proposal as well. The purpose of these changes is to further clarify the intent of the screens and the customer option meeting for the FT study process.

Table 4 – Revised straw proposal to improve the FT process

Appendix DD-Section No.	Appendix DD-Subsection No.	Current Tariff Language	Proposed Tariff Language
5.1, 3rd Paragraph.		Initiating the Fast Track Interconnection Request. To initiate an Interconnection Request under the Fast Track Process, and have the Interconnection Request considered for validation the Interconnection Customer must provide the CAISO with: (i) a completed Interconnection Request as set forth in Appendix 1 ; (ii) a non-refundable processing fee of $500 and a study deposit of $1,000; and	Initiating the Fast Track Interconnection Request. To initiate an Interconnection Request under the Fast Track Process, and have the Interconnection Request considered for validation the Interconnection Customer must provide the CAISO with: (i) a completed Interconnection Request as set forth in Appendix 1 ; (ii) ~~a non-refundable processing fee of **$1000** and~~ a study deposit of ***$25,000***; Discussion of Changes The work group has proposed some significant changes to the screening process. These changes will help further clarify the intent and the application of the screens. However, this does impact the amount of work and data required for the screening process. The nonrefundable processing fees has been eliminated, but the study fee is same as the February 5th proposal. ~~**The proposed fees should address the additional**~~

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
			~~**workload required for the proposed screening process**~~. The study deposit is intended to take care of the modified screening process and the proposed Facility study. The Facility studies will only be performed if the project passes the initial screening process, as clarified in section 5.3.2 of the paper, or as part of a supplemental review study.
5.2		Within fifteen (15) Business Days after the CAISO notifies the Interconnection Customer that the Interconnection Request is deemed complete, valid, and ready to be studied, the applicable Participating TO shall perform an initial review using the screens set forth in Section 5.3 below, shall notify the Interconnection Customer of the results, and shall include with the notification copies of the analysis and data underlying the Participating TO's determinations under the screens.	Within ***Thirty (30)*** ~~***Business***~~ ***Calendar Days*** after the CAISO notifies the Interconnection Customer that the Interconnection Request is deemed complete, valid, and ready to be studied, the applicable Participating TO shall perform an initial review using the screens set forth in Section 5.3 below, shall notify the Interconnection Customer of the results, ***in a report that provides the details*** of the initial review and data underlying the Participating TO's determinations using the screens. Discussion of Changes The group is proposing to increase the time required to perform the initial screening from 15 Business Day to 30 ~~Business~~ Calendar days. The time proposed in our February 5th proposal was 30 Business days which has been changed to 30 Calendar days now .This will ensure that the ISO and PTO have enough time to screen the fast track project for any potential issues. The group is also proposing to issue a report that will provide the details around the application of the screens.
5.3	**5.3.1.2**	For interconnection of a proposed Generating Facility to a radial transmission circuit, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation. For purposes of this Section 5.3.1.2, a line section shall be considered as that portion of a Participating TO's electric	For interconnection of a proposed Generating Facility to a radial transmission circuit **under CAISO control**, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation. For purposes of this Section 5.3.1.2, a line section shall be considered as that portion of a PTO's electric system

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
		system connected to a customer bounded by automatic sectionalizing devices or the end of the transmission line.	connected to a customer bounded by automatic sectionalizing devices or the end of the transmission line. ***<u>This screen will not be required for a proposed interconnection of a Generating Facility to a radial line with no load.</u>*** ***<u>In cases where the circuit lacks the telemetry needed to provide the annual peak load measurement data, power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen.</u>*** <u>Discussion of Changes</u> The proposal to use the latest Generation interconnection Phase I/ Phase II study base case eliminates the confusion about the type of base case needed for the analysis.
	5.3.1.3	For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 percent of a spot network's maximum load or 50 kW. For purposes of this Section 5.3.1.3, a spot network shall be considered as a type of distribution system found in modern commercial buildings for the purpose of providing high reliability of service to a single retail customer.	***Eliminate this screen.*** <u>Discussion of Changes</u> This screen deals with the interconnection of generation facility on the load side of the spot network protector. We are **proposing to remove the screen** from the current FT screening process. The current screen is not appropriate for the interconnection of generators to an ISO controlled facility. It is more suitable for interconnection at distribution level voltages.
	5.3.1.4	The proposed Generating Facility, in aggregation with other generation on the transmission circuit, shall not contribute more than 10 percent to the transmission circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.	The proposed Generating Facility, in aggregation with other ***active FT*** projects on the transmission circuit, shall not contribute more than ***<u>5 percent</u>*** to the transmission circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership. ***The short circuit study data from recently completed Queue Cluster***

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
			studies (Phase I/ Phase II) will be utilized to perform the scree in this Section. Discussion of Changes The proposed 5% threshold provides adequate margin to ensure existing relay settings and coordination are not adversely affected due to the proposed generation in this high level screening process. The Typical margin is 120% which factors in the CT, relay and other modeling errors. The existing 10% limit infringes on the typical margins, and could lead to relay misoperations. The lower threshold also ensures safety and reliability in absence of a detailed short circuit study.
	5.3.1.5	The proposed Generating Facility, in aggregate with other generation on the transmission circuit, shall not cause any transmission protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 percent of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5 percent of the short circuit interrupting capability.	The proposed Generating Facility, in aggregate with other generation on the transmission circuit, shall not cause any transmission protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed ***80 percent*** of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds ***80 percent*** of the short circuit interrupting capability. ***The short circuit study data from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform the scree in this Section*** Discussion of Changes The proposed 80 percent threshold provides additional margin to account for the X/R multiplier. This threshold also ensures safety and reliability in absence of a detailed short circuit study.
	5.3.1.6	The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to interconnect shall not exceed 10 MW in	The Generating Facility, shall not be permitted to interconnect pursuant to the process set forth in this Section 5 in an area where there are known • transient stability limitations; • *voltage & thermal limitations; or*

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
		an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the Point of Interconnection).	• *any other known reliability limitations (e.g., existing or new Special Protection Systems)* to generating units located in the general electrical vicinity (*e.g.*, three or four transmission busses from the Point of Interconnection). <u>Discussion of Changes</u> The existing 10 MW threshold was removed and the additional reliability criteria for screening purposes are proposed. This is to ensure safety and reliability of the system in the absence of technical studies.
Proposed Additional Screens			
	5.3.X1	None	The proposed Generating Facility must interconnect to an existing substation. The proposed interconnection: • Shall be subject to availability of **<u>vacant switch rack position.</u>**~~,~~ • Taps to an existing transmission line shall not be acceptable and the project will fail the screen. **<u>Discussion of Changes</u>** **<u>The telecommunication requirement, as specified in the November 8 straw proposal, could not be determined until the completion of the facility study. The screen was updated to address the issue.</u>**
	5.3.X2	None	The proposed Generating Facility, in the aggregate with other Generating Facilities interconnected to the same transmission circuit, shall not cause the violation of ISO voltage standards, per ISO planning guidelines, on any CAISO controlled facility. Power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen.
	5.3.X3	None	The proposed Generating Facility, in the aggregate with other Generating Facilities interconnected to the same transmission

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
			circuit **on an existing substation**, shall not cause the Power flow on any CAISO-controlled facility to increase by 5 percent, and shall not exceed 80 percent of the same facility's normal rating. Power flow cases from recently completed Queue Cluster studies (Phase I/ Phase II) will be utilized to perform this screen. **Discussion of Changes** **This screen was further modified to ensure that the proposed FT interconnection is on an existing substation. The screen addresses the scope of application to all the CAISO controlled facilities.**
5.3.2		If the proposed interconnection passes the screens and no Upgrades are reasonably anticipated, the Interconnection Request shall be approved. Within fifteen (15) Business Days thereafter, the Participating TO will provide the Interconnection Customer with a Small Generator Interconnection Agreement for execution.	Discussion of Changes The WG determined that to interconnect a FT project that passes the initial screens, the CIASO and PTO will need to conduct an assessment to define the scope of the interconnection that will be reflected in the SGIA. The initial screens do not specify the types of studies that the CAISO and PTO would perform when a FT project passes the initial screens. The WG considered defining the studies as being similar to a facility study. The timelines to perform this assessment may require more time before providing the interconnection customer with an interconnection agreement.
5.3.3.		If the proposed interconnection fails the screens and no Upgrades are reasonably anticipated, but the CAISO and Participating TO determine that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Participating TO shall, within Fifteen (15) Business Days, provide the Interconnection Customer with a Small Generator Interconnection Agreement for execution.	If the proposed interconnection fails the screens ***then, in accordance with section 5.2, the ISO and applicable Participating TO will provide the Interconnection Customer with copies of all data and initial review documentation underlying this conclusion. Also, in accordance with section 5.4, the ISO and Applicable Participating TO will offer to convene a ~~Results meeting~~*** **Customer Options meeting**. Discussion of Changes

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
			It was hard for the group to think of a potential scenario that fits the situation described in this provision. The proposed language better addresses the consequences of failing the screens. Also the proposal to change the name of customers option meeting to results meeting has been dropped.
5.3.4		If the proposed interconnection passes the screens and Upgrades are reasonably anticipated, the CAISO and Participating TO shall provide the Interconnection Customer with the opportunity to attend a customer options meeting as described in Section 5.4.	**We are proposing to eliminate this section.** Discussion of Changes The modifications to the screens were developed to ensure that no NUs would be reasonably anticipated if a project passes all screens. Modified section 5.3.2 should be sufficient to address projects that pass all screens.
5.4		Customer Options Meeting	~~Change the name to **Results meeting**.~~ Discussion of Changes The proposal to change the name of customers option meeting to results meeting has been dropped. This is to be consistent with the order 792 process nomenclature.
5.4.1		Offer to perform facility modifications or modifications to the Participating TO's electric system (*e.g.*, changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Participating TO's electric system;	**We are proposing to eliminate this section.** Discussion of Changes The proposal to include facility study before and during the supplemental study process will address the requirements of this screen.
	5.5.1.	Within ten (10) Business Days following receipt of the deposit for a supplemental review, the CAISO and Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably.	~~.~~ ***The ISO and PTO will perform an assessment to identify the upgrades required for a safe and reliable interconnection of the project.* The Participating TO will provide the Interconnection Customer with a Small Generator Interconnection Agreement for execution after the completion of this assessment.** Discussion of Changes ~~**The WG determined that to interconnect a FT project that passes the screens a facilities study will be needed to define the scope of the interconnection that**~~

Table 4 – Revised straw proposal to improve the FT process			
Appendix DD-Section No.	**Appendix DD-Subsection No.**	**Current Tariff Language**	**Proposed Tariff Language**
			~~will be reflected in the SGIA.~~ The Supplemental Review section of the tariff does not specify the types of studies that would be offered to be performed when a FT project fails the screens. The WG considered defining the studies as being similar to system impact and facility study, and/or a hybrid of the two studies. ~~While the tariff will not be changed to define the type of studies to be performed the timeline is proposed to be extended to 90 15Business days to accommodate the type of studies.~~

4.3 Topic 13 – Clarity regarding timing of transmission cost reimbursement

4.3.1 Background

On November 30, 2011, the ISO filed proposed tariff revisions to its generator interconnection process in FERC Docket No. ER12-502 following the completion of the GIP 2 stakeholder process. Item #6 in the GIP 2 effort addressed repayment of interconnection customer funding for network upgrades associated with a phased generating facility. The ISO tariff provisions to implement item #6, contained in section 12.3.2.2 of appendix Y, stated that upon commercial operation of a phase of a generating facility, the generator is entitled to repayment of the costs of the network upgrades associated with that phase, provided that the network upgrades are in-service. However, the ISO did not explicitly include a similar "in-service" requirement for repayment in the tariff appendix Y provisions regarding the repayment of network upgrades for non-phased facilities (section 12.3.2.1), which refer only to the requirement that a generator have achieved commercial operation in order to qualify for repayment of network upgrade costs funded by that generator.[47]

[47] A phased generating facility is a generating facility that is structured to be completed and to achieve commercial operation in two or more successive partial implementations or phases that are specified in the generator interconnection agreement, such that each phase 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 its entirety at one time.

In the GIP 2 proceeding, LSA and the California Wind Energy Association ("CalWEA") both urged FERC to reject the ISO's proposed in-service requirement for repayment of network upgrade costs for phased facilities. These entities argued that this requirement violated FERC precedent, reasoning that the FERC has never required any other conditions to repayment other than commercial operation of the generator.

In its January 30, 2012 order on the GIP 2 tariff amendment, FERC rejected this argument, in particular the notion that "the achievement of commercial operation is the sole condition required before an interconnection customer becomes eligible for repayment."[48] Instead, FERC explained that in order to ensure that an interconnection customer "bears an appropriate level of risk that network upgrades associated with its generating facility may become unnecessary should the interconnection customer's facility becomes commercially infeasible, the Order No. 2003 series of orders required as a general policy that repayment begin once transmission service to deliver the output of the interconnection customer's generating facility is provided."[49] Because it found that repayment of network upgrades is appropriately tied to the utilization of the transmission provider's network, FERC concluded that the ISO's proposal to require that network upgrades associated with a particular phase be in service prior to the generator being eligible to receive repayment for the costs of those upgrades was just and reasonable and consistent FERC's interconnection policies.

Despite the fact that FERC decided this matter in the context of phased facilities, FERC did not state or suggest that its reasoning was limited to phased facilities, nor does the ISO believe there is any logical reason that FERC's reasoning should be so limited. As with a phased facility, if certain upgrades associated with a non-phased facility have not been placed in service, those upgrades are not being utilized by the generator. Therefore, consistent with FERC's reasoning that the repayment of network upgrades is appropriately tied to the utilization of those upgrades, the ISO does not believe there is a sound basis for retaining the current rule that non-phased generators need only achieve commercial operation in order to be eligible for repayment for all network upgrade costs up-front funded by the generator.

Although the ISO explained in pleadings submitted in the GIP 2 proceeding that it interpreted the tariff provision regarding non-phased facilities as inherently including an in-service requirement, FERC, in a subsequent order on rehearing and clarification of the original GIP 2 order, rejected this interpretation.[50] FERC stated that the "plain language" of the ISO tariff provides that eligibility for repayment for non-phased generators is based solely on the commercial operation date of the

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[48] *California Independent System Operator Corp.*, 138 FERC ¶ 61,060, at P 53 (2012).

[49] *Id*.

[50] *California Independent System Operator Corp.* 140 FERC ¶ 61,168 at P 7 (2012).

generator. FERC stated that if the ISO interprets this provision differently, the ISO should "file revised tariff language to clarify the timing of refunds associated with a non-phased project."[51]

Based on FERC's clarification in the GIP 2 proceeding, the ISO proposed, in its April 12, 2013 tariff amendment in FERC Docket No. ER13-1274, to revise article 11.4.1 of the *pro forma* LGIAs contained in tariff appendices CC and EE to remove existing language requiring an interconnection customer with a non-phased generating facility to wait until the in-service date of corresponding network upgrades prior to being entitled to repayment for the cost of those network upgrades.[52] The ISO explained in that proceeding that its proposed changes to article 11.4.1 of appendices CC and EE would only serve to implement FERC's GIP 2 clarification order and remove any ambiguity from the ISO tariff regarding what conditions apply to repayment of network upgrades cost for non-phased projects.

On June 11, 2013, FERC issued an order accepting the proposed changes, stating that the changes would ensure that the provisions currently found in the *pro forma* LGIAs correspond to the language found in tariff appendices Y and DD, consistent with FERC's clarification in the GIP 2 proceeding, and would serve to remove ambiguity from the existing tariff language regarding what conditions apply to repayment of network upgrade costs for non-phased projects. FERC directed that if the ISO supports modified tariff language to include the in-service requirement, it should file revised tariff language.[53]

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

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

This topic was originally placed within the scope of this initiative because these rules left some stakeholders desiring additional clarity or even a different approach. For example, some generation developers wanted clarity on whether refunds could commence for a completed phased generating facility once the last phase is completed (i.e., whether it would be treated the same as completed non-phased generating facilities). Further, these same generation developers

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51 *Id.*

52 Appendix CC of the ISO tariff contains the *pro forma* LGIA for interconnection requests in a queue cluster window that are tendered an LGIA on or after July 3, 2010 pursuant to tariff appendix Y. Appendix EE of the ISO tariff contains the *pro forma* LGIA for interconnection requests processed under the GIDAP.

53 *California Independent System Operator Corp.*, 143 FERC ¶ 61,228, at P 16 (2013).

also wanted clarity on refund timing when a non-phased generating facility reaches COD before all of its network upgrades are complete. Some of the PTOs expressed the view that reimbursement for network upgrades should not occur until such upgrades are complete and that there is no logical basis for a difference in treatment for phased versus non-phased generating facilities.

As a result, the ISO has been working with stakeholders throughout this initiative to both develop the desired clarity and identify a common approach with broad stakeholder support that can be applied to both phased and non-phased generating facilities. Through a series of papers, the ISO has been attempting to develop a proposal that balances a number of considerations:

1. Alignment with the policies and requirements of the Order No. 2003 series of orders that repayment for transmission assets begin once those assets are utilized to deliver the output of the interconnection customer's generating facility.
2. Elimination of the differential treatment of phased and non-phased projects with respect to timing of reimbursement.
3. Broad stakeholder support.
4. Apply any new rules on a going forward basis.

4.3.2 February 5 revised straw proposal

In its February 5 revised straw proposal, the ISO offered two alternative straw proposals (option A and option B) for stakeholder consideration, and requested that stakeholders comment on the pros and cons and their preferences as to these alternatives.

Option A. Reimbursement based on network upgrades in service at COD and network upgrades in service subsequent to COD. Under this approach, reimbursement is tied to whether network upgrades are in-service and thus is better aligned with the policies and requirements of the Order No. 2003 series of orders (that repayment for transmission assets begin once those assets are utilized to deliver the output of the interconnection customer's generating facility).

1. Reimbursement for in-service network upgrades would commence upon the generating facility or phase achieving commercial operation, as specified in the generator interconnection agreement.
2. Reimbursement for network upgrades placed in service subsequent to the generating facility or phase achieving commercial operation (including those under construction at the time of COD) would commence once the last required network upgrade is placed in service. A variation on this approach could be that reimbursement commence for the aggregate of network upgrades placed in service during some defined time period such as a calendar year.

Option B. Reimbursement based on amounts funded by the interconnection customer through COD and amounts funded by the interconnection customer subsequent to COD. Under this approach, reimbursement is tied to payments made by the interconnection customer, rather than being based on whether network upgrades are in-service. This option is an attempt to address issues raised by PG&E and possibly simplify accounting from a PTO perspective. However, unlike option A, this option could in some circumstances result in reimbursement for network upgrades not yet in-service at the time of COD.

1. Reimbursement for the amounts funded by the interconnection customer up to the time the generating facility or phase achieves commercial operation would commence upon the COD. This could include amounts for required network upgrades not yet in service at the time of COD.
2. Reimbursement for the amounts funded by the interconnection customer subsequent to the time the generating facility or phase achieves commercial operation would commence once the last required network upgrade is placed in service. A variation on this approach could be that reimbursement commence for the aggregate of network upgrades placed in service during some defined time period such as a calendar year.

For each option, the ISO proposed to revise the tariff to apply these new rules on a going-forward basis to both phased and non-phased projects. This feature of the February 5 proposal remained unchanged from the November 8 straw proposal.

4.3.3 Second revised straw proposal

In this section the ISO offers its current proposal for Topic 13.

On February 28 the ISO received written stakeholder comments on its February 5 revised straw proposal. The ISO considered this stakeholder input in the development of the second revised straw proposal described in this section. A summary of the comments received, as well as ISO responses to the issues raised, are provided in the subsequent section.

The following is the ISO's second revised straw proposal for this topic, which is based on Option A:

1. Reimbursement for required network upgrades already in service will commence upon the generating facility or the phase that requires those upgrades achieving commercial operation, as specified in the generator interconnection agreement.
2. Reimbursement for required network upgrades placed in service subsequent to the generating facility or phase achieving commercial operation (including those under construction at the time of the commercial operation date of the project or project Phase) will commence at the beginning of each calendar year for those required network upgrades placed in the service during the prior year calendar year.
3. The ISO proposes to revise the tariff to apply these new rules on a going-forward basis to both phased and non-phased projects. The ISO believes that the appropriate balance between harmonizing the repayment rules and existing customer expectations is to apply

> this new policy beginning with customers who have not yet received a generator interconnection agreement. However, in order to avoid a situation in which customers in the same cluster, or even in the same study group, could be subject to different repayment rules, the ISO proposes to apply these new rules beginning with the customers in the first cluster in which all projects have not yet been tendered a generator interconnection agreement at the time of FERC approval of the ISO proposal on this topic.

The ISO recognizes the concerns raised by PG&E about the potential for retroactive reconciliation of payments being complicated and time consuming, and the potential for multiple reimbursement periods and reimbursement accounts. However, further stakeholder consultation is needed to more thoroughly examine of these issues. In order for the ISO and stakeholders to better understand the feasibility of this approach, including the possible ramifications of this approach for the PTOs and the potential for addressing them, the ISO requests that stakeholders provide comments on this paper limited to the feasibility of implementing Option A rather than Option B. Following receipt of stakeholder comments on this second revised straw proposal on April 16, the ISO will address any issues in a draft final proposal to be posted in May. The ISO plans to take its proposal on this topic to the ISO Board in July.

4.3.4 Stakeholder comments and ISO responses

Stakeholder comments received February 28 following publication of the February 5 revised straw proposal are summarized below. ISO responses to the issues raised are also included in this section.

CPUC staff – Supports reimbursement commencing upon COD for the amounts funded by the interconnection customer up to the time the generating facility or phase achieves commercial operation. For amounts funded by the interconnection customer subsequent to the generating facility or phase achieving commercial operation, supports reimbursement when each network upgrade is placed in service. For delayed network upgrades, reimbursement should commence no later than one year after the completion date specified in the interconnection agreement. Recommends that these new rules be applied to current interconnection customers rather than waiting to apply these new rules beginning with all customers in the first cluster in which all projects have not yet been tendered a generator interconnection agreement at the time of FERC approval of the ISO proposal on this topic.

ISO response: The ISO is not inclined to support reimbursement tied to payments made by interconnection customers by the time COD is achieved (rather than based on the upgrade being placed in service) as this may result in reimbursement for network upgrades not yet in service, which would be inconsistent with the policies and requirements of the Order No. 2003 series of orders that repayment for transmission assets begin once those assets are utilized to deliver the output of the interconnection customer's generating facility. Even in the case of delayed network upgrades, to be consistent with this approach reimbursement should thus not begin until the network upgrade is placed in service.

LSA – Supports both options with some conditions. Supports Option A if reimbursement for network upgrades placed in service subsequent to the generating facility or phase achieving commercial operation commences at the start of each year for network upgrades placed into service the prior year. Supports Option B if reimbursement for network upgrades placed in service subsequent to the generating facility or phase achieving commercial operation commences at the start of each year for network upgrades placed into service the prior year. Also supports a modified Option B in which reimbursement for network upgrade payments made subsequent to the generating facility or phase achieving commercial operation would commence once those payments are made, with an annual refund commencement. LSA also asks how these options would work under the concept of "commercial operation for markets" as described in the ISO's *New Resource Implementation Guide*.[54]

ISO response: The ISO is inclined to support Option A (over Option B) because it is better aligned with the policies and requirements of the Order No. 2003 series of orders that repayment for transmission assets begin once those assets are utilized to deliver the output of the interconnection customer's generating facility. Once the generating facility or phase achieves commercial operation, the ISO is inclined to support allowing reimbursement at the start of each year thereafter for required network upgrades placed in service the prior year, rather than waiting until the last required network upgrade is placed in service. This would help address the situation in which an interconnection customer would otherwise have to wait for reimbursement for a network upgrade that is placed in service long after all other required network upgrades have been placed in service. Lastly, the concept of Commercial Operation for Markets (COM) is not to be confused with Commercial Operation Date (COD). A COD is a date set forth in the generator interconnection agreement (GIA) that designates the official start of commercial operation of either a particular phase of a phased project or the entire project in the case of a non-phased project. For purposes of the reimbursement proposal discussed in this paper, only GIA-specified CODs are relevant. In contrast, any dates associated with a project's utilization of the COM provision are not relevant to reimbursement for network upgrade costs. The COM functionality is designed to enable early participation in the ISO markets – i.e., participation ahead of a GIA-specified COD – by a portion of the generating capacity of a phase of a phased project or a portion of the generating capacity of a non-phased project, while continuing to develop the remaining generating capacity of the project or project phase, including trial operations with test energy for remaining megawatt capacity. Upon approval by the ISO of the project's request to utilize the COM provision, including the proposed COM date or dates, the interconnection customer submits a COM

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[54] http://www.caiso.com/Documents/NewResourceImplementationGuide.doc

letter to the ISO. Each time the project increases the amount of commercial energy as part of its COM implementation, the interconnection customer must submit a new COM letter. However, the COD is achieved only when the associated project or project phase as specified in the GIA is completed in full and is in service. Thus, COM and COD are not equivalent, and a project's use of the COM provisions and any associated COM dates are irrelevant for purposes of reimbursement of network upgrade costs.

PG&E – Supports Option B because it would minimize the number of separate reimbursement accounts that need to be created. PG&E's preferred approach is to limit the number of reimbursement phases to two: pre-COD and post-COD. While PG&E believes that Option A is better than the status quo, it is not their preferred option because retroactive reconciliation of payments made by generators could be complicated and time consuming. PG&E also asks how these options would work under the concept of "commercial operation for markets" as described in the ISO's *New Resource Implementation Guide*.

ISO response: See ISO's previous responses above with regard to Option A versus Option B. With respect to PG&E's concerns about retroactive reconciliation of payments being complicated and time consuming, the ISO believes that it is important to further explore this issue in order for the ISO and stakeholders to understand the ramifications of Option A. The ISO intends to do this through a subsequent paper. See ISO's clarification above about COM versus COD.

Six Cities – Supports Option A because it is the most consistent the approach that reimbursement for network upgrades should commence after the project or phase has achieved commercial operation and all of the associated network upgrades are in service. Does not support Option B because it could result in reimbursement for network upgrades that are not in service at the time the project or phase achieves commercial operation. Six Cities supports the principle that, as a prerequisite for reimbursement, network upgrades should be available for use in delivering the output of an interconnection customer's generating facility.

ISO response: The ISO is also inclined to support Option A for the same reasons.

SCE – Supports Option A. Reimbursement for network upgrades energized subsequent to the time the generating facility or phase achieves commercial operation should commence as soon as the last associated network upgrade is in-service. SCE believes that tying the reimbursement to payments made by the interconnection customer (*i.e.* Option B) rather than being based on whether network upgrades are in-service (*i.e.*, Option A) would be incompatible with FERC's Order 2003 series of orders. SCE agrees that in order to not have interconnection customers in the same study cluster, or even the same study group, negotiate an interconnection agreement and operate under disparate reimbursement rules, that this new policy be applied on a going-forward basis for both phased and non-phased projects.

ISO response: The ISO is also inclined to support Option A for the same reasons. However, once the generating facility or phase achieves commercial operation, the ISO is inclined to support allowing reimbursement at the start of each year thereafter for required network upgrades placed in service the prior year, rather than waiting until the last required network upgrade is placed in service.