California Independent
System Operator Corporation

February 21, 2013

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: California Independent System Operator Corporation
Docket No. ER13-____-000
Stage Two Amendments to Local Market Power Mitigation and Default Competitive Path Assessment Tariff Provisions

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO")[1] submits this filing to amend its tariff in order to implement additional improvements to its local market power mitigation mechanisms that build on the improvements that the Commission accepted last year. These changes will further increase the accuracy and efficiency of the ISO's automated local market power mitigation processes.

The majority of the revisions contained in this tariff amendment implement the second stage of the ISO's planned two-stage process for improving its local market power mitigation provisions. As described in more detail below, these stage two amendments largely build upon the existing stage one revisions accepted by the Commission last year in Docket No. ER12-423.[2] In particular, they will extend the benefits of more accurate and efficient market power mitigation for the day-ahead market and the hour-ahead scheduling process to the real-time market by (1) utilizing the dynamic competitive path assessment to determine transmission constraint competitiveness in the hour-ahead scheduling process and the real-time market; and (2)

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[1] The ISO submits this filing pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the ISO tariff. Except where otherwise noted herein, references to section numbers are references to sections of the tariff.

[2] *See California Independent System Operator Corp.*, 138 FERC ¶ 61,154 (2012) ("stage one order"). The stage one order accepted tariff revisions filed by the ISO on November 16, 2011 to implement stage one of the local market power mitigation ("LMPM") enhancements, effective April 11, 2012 ("LMPM stage one tariff amendment" or "stage one tariff amendment").

adding the automated market power mitigation process every 15 minutes for use in the real-time market processes. In contrast, the ISO is currently using the results of the hour-ahead market power mitigation process for both the hour-ahead scheduling process and the real-time market. In addition, although the ISO is utilizing the stage one decomposition mitigation methodology in the hour-ahead mitigation application, the ISO continues to use the quarterly static competitive path assessment to determine whether a transmission constraint is competitive, a very conservative approach for determining competitiveness. Adding real-time mitigation and implementing the dynamic competitive path assessment in the mitigation performed in the hour-ahead and the real-time will result in a significant improvement in the accuracy and efficiency of the ISO's automated market power mitigation processes.

Because the ISO is proposing to retire the conservative quarterly competitive path assessment, which is also used to determine whether a constraint is non-competitive for purposes of exceptional dispatch settlement, and because of the potential of the dynamic competitive path assessment to fail in production, the ISO is also proposing to implement a default competitive path assessment process that will be employed under two types of circumstances:

(1) to use as a back-up in the event of a failure of the dynamic competitive path assessment, so as to prevent the potential exercise of market power under such circumstances; and

(2) to determine whether a transmission constraint is non-competitive for purposes of exceptional dispatch mitigation.[3]

The methodology used to produce the default competitive path assessment uses sixty days of data produced by the in-market dynamic competitive path assessment.[4] As discussed below, the default competitive path assessment is significantly less conservative than the static competitive path assessment and will, accordingly, also provide for more accurate and less frequent exceptional dispatch mitigation.

The ISO requests that the Commission accept the tariff revisions contained in this filing effective as of May 1, 2013. The ISO also respectfully requests that the Commission issue an order within 60 days of this filing or by April 22, 2013 to ensure an orderly implementation and to consider whether any adjustments are necessary in light of the Commission's order.

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[3] Exceptional dispatches of a resource to address reliability requirements related to non-competitive transmission constraints are subject to the mitigated exceptional dispatch energy settlement, generally at the higher of the resource's default energy bid or the locational marginal price. *See* ISO tariff sections 11.5.6.7.2, 39.10(1).

[4] The ISO will continue to rely on the static competitive path assessment until sufficient data are available to generate a default competitive path assessment.

I. Background

A. The ISO's Current Market Power Mitigation Process

Like the tariffs of all the other independent system operators and regional transmission organizations, the ISO tariff includes provisions to mitigate the ability of suppliers to exercise local market power by unilaterally influencing the price of energy in the ISO's markets. Pursuant to the revisions set forth in the local market power mitigation stage one tariff amendment,[5] the ISO performs local market power mitigation in the day-ahead for the day-ahead market, and in the hour-ahead scheduling process for both the hour-ahead scheduling process and the real-time market.[6] The market power mitigation process analyzes the potential to exercise local market power and determines bid mitigation based on a single processing run that decomposes the locational marginal price for each location into components relating to energy, losses, and competitive and non-competitive congestion. Under this method, which is known as the decomposition method, mitigation is based on the non-competitive congestion component of each locational marginal price.[7] Currently, the day-ahead local market power mitigation process includes the in-market dynamic competitive path assessment. However, the hour-ahead local market power mitigation process continues to use the static competitive path assessment in effect since April 2009.

The purpose of this tariff amendment is to implement stage two of the ISO's local market power mitigation enhancements. Stage two has two features. First, instead of using the hour-ahead local market power mitigation results for both the hour-ahead scheduling process and the real-time market, the ISO will retain the existing process for use in the hour-ahead scheduling process, but will add four separate market power mitigation runs as part of the residual unit commitment process, which runs every 15 minutes. The mitigated bid curves resulting from each real-time mitigation run will be utilized in the relevant real-time market applications, including the five-minute real-time dispatch. Second, the dynamic competitive path assessment will be included in both the hour-ahead and real-time market power mitigation runs.

The ISO's mitigation process is premised on a distinction between competitive and non-competitive transmission constraints. As noted above, as part of the stage one implementation, the competitive path assessment is determined dynamically as part of the day-ahead market. These assessments are called dynamic competitive path

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[5] The stage one tariff amendment is discussed further in the next section of this transmittal letter.

[6] Currently, the mitigation process for the real-time market is performed as part of the ISO's hour-ahead scheduling process. Both the hour-ahead scheduling process and the real-time market processes are conducted in "real-time," as that term is defined in Appendix A to the ISO tariff.

[7] ISO tariff sections 31.2, 33.4.

assessments. In contrast, for the local market power mitigation process performed in the hour-ahead, the ISO continues to use the static competitive path assessment. The ISO's Department of Market Monitoring ("DMM") currently performs static competitive path assessments on a quarterly basis through off-line studies using seasonal study data and considering a range of system conditions, unless the ISO determines that more frequent competitive path assessments are needed.[8] With the exception of Path 15 and Path 26, only transmission constraints tested and determined to be competitive are treated as competitive for purposes of the automated local power mitigation. Moreover, the ISO only tests constraints that were congested or managed for congestion in more than 500 hours in the prior 12 months.[9] Untested constraints and constraints tested and determined to be non-competitive are subject to mitigation. Path 15 and Path 26 are deemed competitive.[10] The ISO also relies on the static competitive path assessment to determine whether a constraint is non-competitive for purposes of mitigating exceptional dispatches to address reliability requirements related to non-competitive transmission constraints.[11]

B. The Local Market Power Mitigation Stage One Tariff Amendment

Many of the features of the ISO's current market power mitigation process were established with tariff revisions filed in stage one of its planned two-stage process for enhancing its local market power mitigation provisions. Those stage one tariff revisions included the following:

- Revisions to implement the decomposition method described above as part of the local market power mitigation process run in the day-ahead market and in the hour-ahead scheduling process, which replaced the time-consuming and less accurate process of performing two pre-market runs (a competitive constraints run and an all-constraints run).

- Revisions to implement the dynamic competitive path assessment described above as part of the day-ahead market power mitigation process, but not the hour-ahead market power mitigation process.

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8 ISO tariff sections 39.7, 39.7.2.

9 ISO tariff section 39.7.2.3.

10 *Id*. Section 39.7.2.3 states that "[a]ssessments of competitive Transmission Constraints for the HASP [hour-ahead scheduling process] or RTM [real-time market] will consider all interfaces to neighboring Balancing Authority Areas and all inter-zonal interfaces that predate the effective date of this provision to be competitive, and no such interfaces will be included in the set of candidate Transmission Constraints for assessment." Path 15 and Path 26 are inter-zonal interfaces that predate the effective date of the provision. Therefore, they are considered to be competitive and are not included in the set of Transmission Constraints for assessments.

11 ISO tariff section 39.10(1).

- Revisions to determine the entities that have control of resources for purposes of determining the resource portfolios used in the dynamic competitive path assessment, including control of resources pursuant to resource control agreements.

The ISO explained that it expected these tariff revisions to result in a more accurate and efficient market power mitigation process.[12] The ISO also explained that it would propose tariff revisions in stage two that would extend the benefits for market power mitigation to the real-time market, but that were not feasible to implement in stage one.[13] The ISO stated that in stage two the ISO would retain the existing hour-ahead local market power mitigation for use in the hour-ahead but perform additional market power mitigation in the real-time market by performing mitigation as part of each 15-minute real-time unit commitment process.[14] In addition, in stage two the ISO would implement dynamic competitive path assessments in the mitigation performed in both the hour-ahead scheduling process and the real-time market.[15]

The Commission accepted the stage one tariff revisions as just and reasonable, effective April 11, 2012 as the ISO requested.[16] The Commission "agree[d] with CAISO's analysis that the proposal will provide for greater efficiency and target units for mitigation in a more efficient and effective manner."[17] The Commission also found that "CAISO's use of a dynamic, rather than a quarterly, assessment of the competitiveness of certain transmission paths should produce results that more accurately reflect market conditions associated with individual transmission constraints."[18] In addition, the Commission found that "CAISO's proposal to implement this process in two stages [is]

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[12] Transmittal letter for the stage one tariff amendment at 9-10; Direct Testimony of Lin Xu, Attachment C to the stage one tariff amendment, at 17-19; Direct Testimony of Jeffrey E. McDonald, Attachment E to the stage one tariff amendment, at 15-27.

[13] Transmittal letter for the stage one tariff amendment at 10, 14-15, 18; Direct Testimony of Khaled Abdul-Rahman, Attachment D to the stage one tariff amendment, at 7-12.

[14] Transmittal letter for the stage one tariff amendment at 10.

[15] *Id.* at 14-15.

[16] Stage one order at P 1. As noted in footnotes 12 and 13 above, the ISO's stage one tariff amendment was supported by testimony from three ISO experts. The ISO is relying on the precedent of the stage one order for the justness and reasonableness of the stage two amendments that bring the benefits of day-ahead enhancements into the real-time market.

[17] Stage one order at P 19. In the stage one order, the Commission referred to the ISO as CAISO.

[18] *Id.* at P 35.

reasonable because the performance risk and software enhancements in the day-ahead market are not as substantial as the real-time market."[19]

C. Benefits of Implementing the Local Market Power Mitigation Enhancements in the Day-Ahead Market

The ISO's DMM has performed analyses that confirm that the day-ahead stage one tariff revisions have improved the accuracy of the ISO's local market power mitigation. The DMM explained that local market power is created by two factors: (1) congestion that limits the supply of imported electricity into the congested area; and (2) insufficient or concentrated control of supply within the congested area.[20] As to the first of these factors, the revised market power mitigation process has significantly improved the ISO's ability to accurately predict congestion on transmission constraints in the subsequent market run where local market power may be exercised. Specifically, the revised process allowed the ISO to accurately predict congestion 93 percent of the time in the second quarter of 2012, as compared with 45 percent of the time in the second quarter of 2011, *i.e.*, prior to implementation of the stage one tariff revisions. Further, under the revised process, the ISO over-identified congestion only 3 percent of the time in the second quarter of 2012 (compared with 18 percent over-identification a year earlier), and the ISO under-identified congestion only 4 percent of the time (compared with 37 percent under-identification a year earlier).[21]

In addition, the DMM explains, in the Market Issues and Performance Report, that implementation of the dynamic competitive path assessment has significantly improved the ISO's ability to evaluate whether there is insufficient or concentrated control of supply within a congested area, *i.e.*, the competitiveness of supply to relieve congestion on binding constraints. In particular, for the second quarter of 2012, the dynamic competitive path assessment for the day-ahead market resulted in considerably more accurate path designations, and thus more accurate application of local market power mitigation, than did the superseded static competitive path assessment for the day-ahead market. Most of the improvement in accuracy arose from fewer instances where the assessment inaccurately designated a path as non-competitive. The dynamic competitive path assessment also determined whether transmission constraints were non-competitive with 85 percent accuracy overall, whereas the static competitive path assessment was only 32 percent accurate.[22] Both

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[19] *Id.* at P 36.

[20] Q2 2012 Report on Market Issues and Performance at 40 (Aug. 14, 2012) ("Market Issues and Performance Report"). This report is provided in Attachment C to this filing and is available on the ISO website at http://www.caiso.com/Documents/2012SecondQuarterReport-MarketIssues-Performance-August2012.pdf.

[21] *Id.* at 41.

[22] *Id.* at 41-43.

measures demonstrate significant improvements in accuracy, thereby substantially reducing over-mitigation.

As discussed below, the DMM's analysis also indicates that implementing the local market power mitigation enhancements in this stage two tariff amendment will improve the accuracy and reduce the frequency of mitigation in the real-time market.[23]

D. The Default Competitive Path Assessment

As discussed in more detail below,[24] while the ISO was developing the implementation detail for the stage two local market power mitigation process, it discovered that implementing the stage two mitigation process would create two gaps that needed to be addressed. Both gaps would result from performing dynamic competitive path assessments for the hour-ahead scheduling process and the real-time market. First, unlike the static competitive path assessments that the DMM currently performs for those markets, the software used to perform the dynamic competitive path assessment could fail for the applicable market run.[25] Second, the ISO could not rely on the results of the competitive path assessment to determine whether a transmission constraint is non-competitive for purposes of mitigating exceptional dispatches, because issuance of the exceptional dispatches may prevent congestion from occurring on the constraint and thereby result in the constraint being treated as competitive in the dynamic competitive path assessment over the time period of the exceptional dispatch.

In this tariff amendment the ISO proposes to implement a default competitive path assessment to prevent either of these two gaps from occurring. The default competitive path assessment will apply in two circumstances: (1) as a back-up measure in the event that a failure of the ISO's market software prevents the software from performing a dynamic competitive path assessment; and (2) in order to determine whether exceptional dispatches are related to a non-competitive transmission constraint for purposes of mitigation of the exceptional dispatches in real-time.

E. The Stakeholder Process for the Stage Two Tariff Amendment

The ISO established a stakeholder process on October 1, 2010 for the market power mitigation enhancements that included both the new decomposition methodology and the dynamic competitive path assessment.[26] Due to implementation challenges,

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[23] See section II(A) of this transmittal letter.

[24] See section II(E) of this transmittal letter.

[25] The software used to perform the dynamic competitive path assessment can also fail for the day-ahead market run, but a failure is somewhat less likely in the day-ahead as compared with the real-time because the real-time market power mitigation will occur more frequently and will allow little time to correct for any software failure that may occur.

[26] Transmittal letter for the stage one tariff amendment at 4-5.

the ISO decided to file two separate tariff amendments to implement stage one and stage two.[27] On July 14, 2011, the ISO Governing Board ("Board") authorized the ISO to prepare and file the stage one and stage two enhancements.[28]

At the time it submitted the stage one filing tariff amendment, the ISO anticipated that it would submit the tariff revisions to implement stage two in the fourth quarter of 2012.[29] However, on July 16, 2012, the ISO was compelled to issue a market notice explaining that it needed to postpone implementation of the stage two revisions to allow more time for software design, development, and testing. The market notice stated that the implementation of stage two was expected to occur with the next major scheduled release of ISO market enhancements, the spring 2013 release.[30]

On July 23, 2012, the ISO initiated another stakeholder process to develop default competitive path designations that will apply in the two circumstances discussed above.[31] At its December 14, 2012 meeting, the Board authorized the ISO to prepare and submit tariff revisions to implement this proposal.[32]

The ISO combined the stakeholder process for developing the local market power mitigation stage two tariff revisions and the stakeholder process for implementing default competitive path designations. On December 18, 2012, the ISO issued draft tariff language to implement all of these changes, and requested stakeholders' written comments by January 7, 2013. Four stakeholders provided written comments; two of the sets of comments proposed clarifying revisions to the draft tariff language, and the

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27 *See, e.g.*, Revised Draft Final Proposal – Dynamic Competitive Path Assessment at 1-2 (July 5, 2011). This paper is provided in Attachment E to this filing and available on the ISO's website at http://www.caiso.com/Documents/RevisedDraftFinalProposal-DynamicCompetitivePathAssessment.pdf.

28 Materials related to the ISO Governing Board's approval are available on the ISO's website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx. Those materials were also provided in Attachment H to the stage one tariff amendment.

29 Transmittal letter for the stage one tariff amendment at 18.

30 http://www.caiso.com/Documents/LocalMarketPowerMitigationEnhancementsPhase2-ImplementationDelayed.htm. *See also* http://www.caiso.com/Documents/BriefingLocalMarketPowerMitigationScheduleDelay-Presentation-July2012.pdf (briefing on the postponement of stage two provided to the Board).

31 Materials related to this stakeholder process are available on the ISO's website at http://www.caiso.com/informed/Pages/StakeholderProcesses/ExceptionalDispatchMitigationInRealTime.aspx.

32 Materials related to the Board's approval of this component are provided in Attachment H to this filing and are available on the ISO's website at http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx. The materials include a memorandum provided by Keith Casey, Vice President, Market & Infrastructure Development to the Board on December 6, 2012 ("December 6 Memorandum").

other two sets proposed no revisions. The ISO held a conference call on January 15, 2013 to discuss the comments. On January 28, 2013 the ISO issued a revised draft showing incremental changes to the tariff language based on the comments and the ISO's own further review.[33]

Stakeholders generally supported the ISO's local market power mitigation tariff revisions for both stage one and two. Also, stakeholders were generally receptive to the ISO's proposal for a default competitive path assessment, once they realized that the ISO was not proposing additional exceptional dispatch mitigation, but rather an alternative approach for determining whether a constraint is non-competitive for purposes of existing exceptional dispatch mitigation rules.[34] As of this filing, the ISO is not aware of any major objections to its proposal from parties that participated in the stakeholder process.[35]

II. Discussion of Tariff Revisions

A. Extending the Benefits of the Local Market Power Mitigation Enhancements from the Day-Ahead Market to the Real-Time Market Is Just and Reasonable

The local market power mitigation enhancements proposed in this filing are just and reasonable. In the stage one order, the Commission found that the ISO's proposed tariff revisions to enhance its local market power mitigation process and implement the dynamic competitive path assessment were just and reasonable because they would improve the accuracy and efficiency of the ISO's automated market power mitigation processes.[36] The stage two local market mitigation enhancements will extend the benefits of more accurate and efficient market power mitigation by adding real-time mitigation and implementing the dynamic competitive path assessment in the hour-ahead and the real-time and performing mitigation assessments in real-time.

The DMM has issued a white paper concerning the impact of the enhancements to the local market power mitigation and the dynamic competitive path assessment, which includes an analysis of the expected benefits of implementing the stage two tariff

[33] A list of key dates in the ISO stakeholder process for the market power mitigation enhancements is provided in Attachment I to this filing. Materials related to the stakeholder process are available on the CAISO's website at http://www.caiso.com/2822/28229d8a4b370.html.

[34] Stakeholders expressed concern over the frequency of exceptional dispatch, which is an issue beyond the scope of these proposed amendments.

[35] The ISO discusses comments that stakeholders provided in section II of this transmittal letter.

[36] Stage one order at PP 19, 35.

revisions.[37] This assessment explained that the stage two revisions will result in both improved prediction of congestion and more accurate assessment of the supply available to relieve congestion.[38] Further, the improved accuracy and reduced frequency of mitigation resulting from the stage one tariff revisions is expected to continue after the stage two tariff revisions are implemented.[39]

In particular, implementing the real-time local market power mitigation processes including the dynamic competitive path assessment is expected to result in about 86 percent of path designations being assessed correctly – an improvement of about 21 percent over the accuracy of relying on the hour-ahead mitigation process only (*i.e.*, 65 percent accuracy of relying on hour-ahead mitigation results for the real-time market).[40] Also, adding real-time mitigation is expected to result in a decrease in instances where an uncompetitive path is incorrectly deemed competitive from about 29 percent to about 9 percent, which constitutes a significant improvement in reducing under-identification of local market power.[41]

B. Market Power Mitigation Process for the Hour-Ahead Scheduling Process and the Real-Time Market

For stage two, the ISO proposes to modify tariff section 33.4, which currently describes the market power mitigation process for both the hour-ahead scheduling process and the real-time market, to apply solely to the hour-ahead scheduling process. The market power mitigation process for the real-time market will now be addressed in new tariff section 34.2.3, discussed below. The ISO also proposes to add a sentence to section 33.4 to make it clear that, for reliability must-run ("RMR") units, RMR proxy bids resulting from the market power mitigation process for the hour-ahead scheduling process will be utilized in both the hour-ahead scheduling process optimization and all real-time market processes for each trading hour. In addition, the ISO proposes to clarify in section 33.4 that, just like bids on behalf of demand response resources under the existing tariff, bids on behalf of participating load and non-generator resources are

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[37] Assessment of the Impact of Proposed Local Market Power Mitigation Enhancements at 4, 14-16 (Feb. 9, 2012) ("Assessment of Enhancements"). The Assessment of Enhancements is provided in Attachment D to this filing and is available on the ISO website at http://www.caiso.com/Documents/WhitePaperAssessmentImpactProposedLocalMarketPowerMitigationEnhancements.pdf.

[38] *Id.* at 4.

[39] *Id.*

[40] *Id.* at 16.

[41] *Id.*

considered in the market power mitigation process but are not subject to bid mitigation.[42]

The ISO proposes to add new section 34.2.3 to set forth the market power mitigation process for the real-time market. The structure of section 34.2.3 largely parallels the structure of section 33.4. The major difference between the existing mitigation assessment for bids in the real-time market, as conducted in the hour-ahead scheduling process, and the more granular process proposed in this tariff amendment, is that real-time market bids will be evaluated for each 15-minute interval of the relevant trading hour. Under section 34.2.3, if a bid is mitigated in the market power mitigation process for the first 15-minute interval for a trading hour, the mitigated bid will be utilized for all market applications for that first interval. If a bid is not mitigated in the first 15-minute interval, it is subject to mitigation in subsequent 15-minute intervals of the trading hour as determined in the market power mitigation runs for the subsequent intervals. For each trading hour, any bid mitigated in a prior 15-minute interval of that trading hour will continue to be mitigated in subsequent intervals of that trading hour and may be further mitigated as determined in the market power mitigation runs for any subsequent intervals.

The ISO also proposes to revise tariff section 34.2, which describes the real-time unit commitment process, to clarify the timing and scope of responsibility of the hour-ahead scheduling process.[43]

C. Competitive Path Assessment

1. Clarification of the Existing Dynamic Competitive Path Assessment Methodology for the Day-Ahead Market

The ISO proposes to clarify the provisions in tariff section 39.7.2.2(a) that set forth the existing dynamic competitive path assessment methodology for the day-ahead market. In particular, the ISO has clarified that the determination of whether a transmission constraint is designated as non-competitive includes consideration of available capacity from internal resources and internal virtual supply awards only, rather than consideration of internal and external available capacity and virtual supply awards.[44] This clarification harmonizes with existing language in the section stating that

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[42] The ISO also proposes to make the same clarification in tariff section 31.2 with regard to the day-ahead market power mitigation process.

[43] As stated in section 34.2, the hour-ahead scheduling process is a special real-time unit commitment run.

[44] Revised ISO tariff sections 39.7.2.2(a)(ii), 39.7.2.2(a)(v).

only internal resources and virtual supply awards are to be considered in the determination.[45]

In addition, the ISO has clarified that market participants without physical resources (*i.e.*, market participants that engage in purely virtual or financial transactions) will be deemed to be net sellers for purposes of the section.[46] This clarification will ensure that all internal virtual supply that can provide counter-flow to a transmission constraint is included when assessing the competitiveness of the constraint. Inclusion of the internal virtual supply will prevent a situation where effective virtual supply useful to providing counter-flow can potentially displace lower-cost physical generation in the competitiveness assessment and circumvent effective local market power mitigation. This potential situation is similar to a concern that the DMM identified when the ISO was developing its tariff revisions to implement convergence bidding.[47]

2. Implementation of the Dynamic Competitive Path Assessment for the Hour-Ahead Scheduling Process and the Real-Time Market

The tariff revisions to implement the dynamic competitive path assessment for the hour-ahead scheduling process and the real-time market are set forth in revised tariff section 39.7.2.2(b), which parallels the structure of the existing tariff section that sets forth the dynamic competitive path assessment methodology for the day-ahead market.[48] Pursuant to the proposed tariff revisions, the ISO will designate a transmission constraint for the hour-ahead scheduling process or the real-time market as non-competitive when the sum of the ramp-constrained available capacity from internal resources, excluding the amount of ramp-constrained capacity that can be withheld by the potentially pivotal supplier portfolios, is less than the demand for counter-flow to that transmission constraint from internal resources.[49] By comparison,

[45] ISO tariff section 39.7.2.2(a)(iii) (stating that demand for counter-flow to the transmission constraint means "all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint").

[46] Revised ISO tariff section 39.7.2.2(vi).

[47] *See* Convergence Bidding: Department of Market Monitoring Recommendations at Attachment A (Examples of Convergence Bidding and Local Market Power Mitigation) at 9-12 (Nov. 7, 2007), available on the ISO website at http://www.caiso.com/1c8f/1c8ff4236e8e0.pdf. The requirement is currently set forth in Attachment B, Section B.2.1.1 of the Business Practice Manual for Market Operations, which is available on the ISO website at http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations. The ISO is proposing to expressly include this detail in the tariff, which is consistent with how net buyers are determined under existing ISO tariff section 39.7.2.2.

[48] ISO tariff section 39.7.2.2(a).

[49] Proposed ISO tariff section 39.7.2.2(b).

under the existing dynamic competitive path assessment methodology for the day-ahead market, the ISO designates a transmission constraint for the day-ahead market as non-competitive based solely on whether the supply of counter-flow to the transmission constraint from all portfolios of suppliers not identified as potentially pivotal (excluding portfolios of potentially pivotal suppliers to the transmission constraint) is less than the demand for counter-flow to the transmission constraint.[50] The reason for this difference is that in the hour-ahead scheduling process and the real-time market, ramping constraints on the physical resources belonging to the potentially pivotal suppliers reduce the amount of capacity that can be withheld, but in the day-ahead market the entire output of physical resources belonging to the potentially pivotal suppliers can be withheld.[51]

The proposed tariff revisions define each component of the test for determining whether a transmission constraint for the hour-ahead scheduling process and the real-time market should be designated as non-competitive.[52] Some of these new definitions are similar but not identical to the existing definitions for the dynamic competitive path assessment methodology for the day-ahead market. For example, the new definitions reflect ramping constraints, whereas the existing definitions do not, for the reasons explained above.[53] Also, unlike the existing definitions, the new definitions do not include virtual supply awards, because virtual bids liquidate in the real-time market and thus there are no virtual resources to consider in the dynamic competitive path assessment for the hour-ahead scheduling process or the real-time market.[54]

The ISO also proposes to delete language in existing tariff sections 39.7, 39.7.2.1, and 39.7.2.2(b), and the entirety of tariff sections 39.7.2.3 and 39.7.2.4, all of which concern the static competitive path assessment for the hour-ahead scheduling process and the real-time market. Those tariff sections will no longer be applicable once the dynamic competitive path assessment methodology for the hour-ahead scheduling process and the real-time market goes into effect, except, as discussed below, that the ISO proposes to retain the most recently produced static competitive path assessment for use until enough data are generated using the new dynamic competitive path assessment to generate default competitive path assessments.

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[50] ISO tariff section 39.7.2.2(a).

[51] Revised Draft Final Proposal on Dynamic Competitive Path Assessment at 6-7.

[52] Proposed tariff sections 39.7.2.2(b)(i)-(vii).

[53] Proposed ISO tariff section 39.7.2.2(b)(iii). *See also* Revised Draft Final Proposal on Dynamic Competitive Path Assessment at 11.

[54] *Id.*

D. Clarifications Regarding the Provision of Information on Resource Control Agreements

The ISO proposes to clarify the existing tariff provisions regarding resource control agreements to include requirements that are already set forth in the applicable practice manual.[55] Specifically, the ISO clarifies in tariff section 4.5.1.1.13 that each scheduling coordinator applicant and scheduling coordinator will register with the ISO any resource that any affiliate that satisfies the criteria set forth in tariff section 4.5.1.1.12 controls through a resource control agreement to which the scheduling coordinator applicant, scheduling coordinator, or affiliate is a party.[56] The ISO also clarifies in section 4.5.1.1.13 that each scheduling coordinator applicant or scheduling coordinator that is a party to a resource control agreement, or that has any affiliate that satisfies the criteria in section 4.5.1.1.12 and is a party to a resource control agreement, will submit information regarding the resource control agreement to the ISO in accordance with the procedures set forth in the applicable business practice manual. In addition, the ISO has clarified in tariff section 4.5.1.2.1.1 that each scheduling coordinator has an ongoing obligation to inform the ISO of any changes to information regarding a resource control agreement pursuant to section 4.5.1.1.13.

The ISO also proposes to clarify in the tariff that, as already set forth in the applicable business practice manual,[57] a scheduling coordinator is required to report any agreement under which the scheduling coordinator assigns responsibility for serving as scheduling coordinator for a resource it controls to another entity. Specifically, the ISO has clarified the definition of the term *resource control agreement* to state that a resource control agreement includes but is not limited to any agreement under which an entity controls a resource that uses a scheduling coordinator identification code assigned to a scheduling coordinator that is not an affiliate of the controlling entity.

In addition, the ISO proposes to clarify section 4.5.1.1.13 to recognize that a utility subject to the jurisdiction of a local regulatory authority cannot control the bidding and scheduling of a resource by an unregulated affiliate with which the utility is not a party to a resource control agreement, and so the resource should not be counted in the utility's own portfolio for purposes of the dynamic competitive path assessment. Pursuant to section 4.5.1.1.13 as clarified in this tariff amendment, such a utility is not

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55 *See* Business Practice Manual for Scheduling Coordinator Certification & Termination and Convergence Bidding Entity Registration & Termination at 28-30 (Version 5, Feb. 13, 2012) ("BPM for SC Certification"). The BPM for SC Certification is available on the ISO website at http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Scheduling Coordinator Certification and Termination.

56 Tariff section 4.5.1.1.12 sets forth affiliate disclosure requirements. The ISO does not propose to modify section 4.5.1.1.12 in this stage two tariff amendment.

57 *See* BPM for SC Certification at 30-31.

obligated to disclose resource control agreements entered into by an unregulated affiliate unless the resource control agreement is between the utility and the unregulated affiliate. Such an unregulated affiliate is not treated as an affiliate of the utility for purposes of determining supply portfolios under the dynamic competitive path assessment.

E. Implementation of Default Competitive Path Designations

1. Need for Default Competitive Path Designations

Pursuant to the stage two tariff revisions, the ISO will perform dynamic competitive path assessments for the hour-ahead scheduling process and the real-time market, and the ISO will stop creating and using the static competitive path assessment except for an interim period until sufficient data are generated from the dynamic competitive path assessments to create the default competitive path assessments. The ISO realized as it was developing the implementation details for the stage two local market power mitigation process that this evolution caused two gaps that needed to be addressed. First, unlike the static competitive path assessment, the dynamic competitive path assessment could fail for the applicable market run. Unless there is a default competitive path assessment, bids will not be subject to mitigation. Second, the dynamic competitive path assessment cannot be utilized to determine whether a transmission constraint is non-competitive for purposes of exceptional dispatch mitigation. Accordingly, the ISO decided that it needed to implement default competitive path designations that will be employed: (1) as a back-up measure in the event of a failure of the dynamic competitive path assessment; and (2) in order to determine whether a transmission constraint is non-competitive for purposes of exceptional dispatch mitigation.[58]

With regard to the potential for a failure of the dynamic competitive path assessment, it is just and reasonable for the ISO to employ a default competitive path designation as a back-up measure in the event that the ISO's market software cannot perform a dynamic competitive path assessment. Without a default competitive path assessment, bids will not be mitigated. The ISO does not expect that software failures will be common or predictable, as no failures have occurred in the day-ahead market since stage one was implemented in April 2012. However, the real-time market power mitigation will occur four times per hour for each hour in the day, with very little time to attempt to correct for any software failure that may occur, making a failure of the dynamic competitive path assessment somewhat more likely in the real-time than the

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[58] Use of default competitive path designations for these two purposes is discussed in a paper issued in the stakeholder process entitled Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 – Revised Draft Final Proposal (Oct. 30, 2012) ("Revised Draft Final Proposal on Default Competitive Path Designations"). This paper is provided in Attachment F to this filing and is available on the ISO website at http://www.caiso.com/Documents/RevisedDraftFinalProposal-ExceptionalDispatchMitigationRealTime.pdf.

day-ahead.[59] Therefore, it is prudent to maintain a set of default competitive path assessments to utilize in the case of market software failures.

It is also just and reasonable to utilize default competitive path assessments to determine whether an exceptional dispatch is made for the purpose of addressing a reliability requirement relating to a non-competitive transmission constraint, and therefore subject to mitigation, because the dynamic competitive path assessment will not provide a meaningful indication of transmission constraint competitiveness in this context. Exceptional dispatches used to address reliability requirements related to transmission constraints are often issued in advance of anticipated problems on the system, based on observed system and market conditions that cannot be managed by the market software.[60] Such an exceptional dispatch could have the result of preventing congestion from occurring on a transmission constraint and thereby result in the transmission constraint being treated as competitive in the dynamic competitive path assessments over the time period of the exceptional dispatch, regardless of whether it was actually competitive at the time the exceptional dispatch was performed.

Therefore, although the use of dynamic competitive path assessments will improve the accuracy of local market power mitigation in the ISO's markets, using such assessments to determine whether a constraint is non-competitive for purposes of exceptional dispatch has a serious potential for under-detecting the possible exercise of local market power.[61] Under the ISO's current process, this is not a problem because ISO dispatchers determine whether an exceptional dispatch is for a non-competitive constraint by consulting the existing quarterly static list of competitive transmission constraints produced by the DMM.[62] If the transmission constraint does not appear on the list, the transmission constraint is non-competitive, and therefore the exceptional dispatch is subject to mitigation.[63] However, if the ISO was to utilize the dynamic competitive path assessment to perform this analysis, it is likely that constraints that would otherwise test as non-competitive would be identified as competitive because the

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[59] December 6 Memorandum at 5.

[60] Revised Draft Final Proposal on Default Competitive Path Designations at 4; ISO tariff amendment, Docket No. ER12-2539-000, Attachment C (testimony of Mark A. Rothleder) at 4 (Aug. 28, 2012) (explaining that the ISO must use exceptional dispatch "where the ISO operator anticipates congestion could occur on a specific transmission constraint and there is reason to believe, perhaps based on recent history, that the market software will not be able to manage that congestion effectively").

[61] Revised Draft Final Proposal on Default Competitive Path Designations at 4.

[62] *See* ISO tariff section 39.7.2.1.

[63] ISO tariff section 39.10(1) ("The CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of . . . addressing reliability requirements related to non-competitive Transmission Constraints"). *See also* ISO tariff sections 39.10.1, 39.10.2 (setting forth how the mitigated price for exceptional dispatches is determined).

exceptional dispatch at issue would relieve the congestion that would cause the constraint to be binding in the first place. As such, the dynamic competitive path assessment is not an accurate means to determine the mitigation of exceptional dispatches. Although the ISO could presumably continue to employ the existing static designation system for this purpose, the ISO is proposing instead to utilize default competitive path assessments that reflect the analysis performed as part of the more accurate dynamic assessment process, which will increase the accuracy of exceptional dispatch mitigation.

The ISO's DMM has had a significant role in identifying the need and methodology for the proposed default competitive path assessment and supports this proposal. Also, the ISO's Market Surveillance Committee issued an opinion supporting the proposal for both of the ISO's intended uses.[64] Moreover, stakeholders generally indicated support for the default competitive path designations.[65]

2. Design of the Default Competitive Path Designations

The ISO considered several options for creating default competitive path assessments, including retaining the existing static assessment mechanism. However, the ISO ultimately concluded that although the dynamic competitive path assessment mechanism cannot be utilized in the event of a market failure and would not be appropriate for determining mitigation of exceptional dispatches, the more accurate results of the dynamic assessment could nevertheless be used as the basis for creating a set of default competitive path assessments. As a result, the benefits of the dynamic competitive path assessment will flow through to the default assessment.

Specifically, the ISO will determine the competitiveness or non-competitiveness of transmission constraints for purposes of creating default competitive path assessments based on the following two criteria: (1) whether congestion occurred on the transmission constraint in ten or more hours for which the transmission constraint was tested for competitiveness; and (2) whether the transmission constraint was deemed competitive in 75 percent or more of the instances in which the transmission constraint was binding when tested. These tests will utilize data from dynamic competitive path assessments conducted during the most recent 60 days for which data is available, and will be updated no less frequently than once every seven days. The ISO will designate the transmission constraint as non-competitive if the criteria are not met, or if the ISO lacks sufficient data to determine whether these criteria are met.[66]

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64 Market Surveillance Committee Opinion on Mitigation Measures for Exceptional Dispatch in Real-Time at 1 (Dec. 5, 2012) ("MSC Opinion). The MSC Opinion is provided in Attachment G to this filing and is available on the ISO website at http://www.caiso.com/Documents/FinalOpinion-ExceptionalDispatchMitigation-Real-Time.pdf.

65 As explained in Section II.D.3 below, some stakeholders expressed concern regarding exceptional dispatch frequency, but ultimately recognized that such issues are beyond the scope of this tariff amendment.

66 Proposed ISO tariff sections 39.7.3.1, 39.7.3.2.

The only exception to these criteria will be for Path 15 and Path 26. The default designations for these paths will be determined in the same manner as all other transmission constraints except that they will be deemed competitive unless they tested as competitive in *fewer* than 75 percent of the instances in which they were binding.[67]

a. The Criteria for Determining Competitiveness or Non-Competitiveness Are Just and Reasonable

The proposed thresholds for determining the default competitive path assessments are just and reasonable because they prevent the risk of under-mitigation, while at the same time not being so conservative (*i.e.*, difficult to meet) that they would result in transmission constraints being deemed non-competitive when they should be found to be competitive – in order words, using these criteria reasonably avoids the risk of *over*-mitigating transmission constraints particularly when compared with the current static competitive path assessment.[68] The use of the proposed ten-hour threshold ensures that determinations of default competitive path designations are made for each transmission constraint based on a meaningful number of hours that congestion occurred on the transmission constraint after it was tested for competitiveness. Use of the 75 percent threshold is supported by the results of a statistical test the ISO performed to determine when it could be reasonably confident that a transmission constraint had been predominantly competitive in recent history and is therefore likely to have been competitive at the time of the exceptional dispatch. The test results indicated that using a straightforward 75 percent threshold would signal competitiveness with approximately as much accuracy as the more complex statistical approach evaluated by the DMM.[69]

Further, applying the thresholds over the previous 60 trading days is appropriate because the 60-day period is long enough to capture seasonal differences and hours of potential congestion, yet is significantly more granular than the existing static competitive path assessment. The trigger for testing under the static competitive path assessment requires an evaluation of transmission constraints that were congested or

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[67] Proposed ISO tariff sections 39.7.3.3, 39.7.3.4.

[68] *See* Revised Draft Final Proposal on Default Competitive Path Designations at 10; December 6 Memorandum at 2 ("This proposal provides adequate coverage for identifying local market power related to exceptional dispatch [and] strikes a balance between a highly conservative application of mitigation and under-mitigation of local market power"); *id.* at page 2 of Attachment A ("Management has demonstrated that statistical tests give results as the proposed triggers, which are a good balance given the asymmetric risk of under mitigation").

[69] Revised Draft Final Proposal on Default Competitive Path Designations at 6-10. The ISO explained that the 75 percent threshold provides reasonable confidence that a transmission constraint for which an exceptional dispatch is issued is competitive. The ISO noted that, although higher degrees of confidence (generally 90-99 percent) are most often applied in statistical hypothesis testing, in this case the 75 percent threshold was appropriate in recognition of the conservative three pivotal supplier test that underlay the historical data on which the statistical test was based. *Id.* at 7.

managed for congestion in more than 500 hours over 12 months. By comparison, the proposed default competitive path assessment is based on an evaluation of congestion in ten hours over 60 days. This represents a significant decrease of the threshold, greatly reducing the frequency of constraints being deemed non-competitive simply by virtue of not meeting the thresholds.

For these reasons, applying the bright-line ten-hour and 75 percent thresholds over the previous 60 trading days in order to determine whether a transmission constraint is considered competitive or non-competitive for purposes of the default competitive path designations is within the zone of reasonableness required by the Federal Power Act.[70]

b. It Is Just and Reasonable To Assume that Transmission Constraints other than Path 15 and Path 26 Are Non-Competitive for Purposes of Default Path Designations Unless They Meet the Competitiveness Criteria

As indicated above, except for Paths 15 and 26, the ISO will designate a transmission constraint as non-competitive unless it meets the above criteria, including situations in which the ISO lacks sufficient data to determine whether these criteria are satisfied. This assumption of non-competitiveness is appropriate because under the ISO's proposed default competitive path assessment there is a higher risk of under-mitigation associated with assuming that such transmission constraints are competitive relative to the risk of over-mitigation associated with an assumption of non-competitiveness.

In situations involving the failure of the ISO's market software or exceptional dispatches, the ISO is unable to utilize a dynamic assessment to determine whether a transmission path is competitive. In the case of software failure, the cause is clear – an inability to run the test at all. With respect to exceptional dispatches, as explained above, the dynamic competitive path assessment cannot provide a meaningful indication as to competitiveness because that assessment relies on the presence of congestion to test for market power and an exceptional dispatch could have the result of preventing congestion from occurring in the first place. In both cases, there is a good chance that the absence of testing would result in the ISO under-detecting the presence of local market power. Therefore, unlike the dynamic competitive path assessment, an

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[70] As the Commission has explained, "the courts and the Commission have recognized that there is not a single just and reasonable rate. Instead, we evaluate [proposals under FPA section 205] to determine whether they fall into a zone of reasonableness. So long as the end result is just and reasonable, the [proposal] will satisfy the statutory standard." *Calpine Corp. v. California Independent System Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009) (citations omitted).

assumption of competitiveness with respect to the default competitive path designations would create a significant risk of under-mitigation.[71]

The ISO weighed this risk against the reduced potential for over-mitigation associated with the proposed default competitive path assessment. As noted in the MSC Opinion, the default competitive path assessment will result in more transmission paths being evaluated and found to be competitive as compared to the ISO's current static assessment process under which the majority of transmission paths are deemed non-competitive by default. As such, even with the assumption of non-competitiveness, this mechanism constitutes a relaxation of mitigation relative to the current procedures.[72] Moreover, the ISO expects that the majority of constraints that are deemed non-competitive due to a lack of modeling information would consist of minor transmission paths that are by their very nature more likely to be affected by local market power. Based on these facts, the ISO reasonably concluded that the risk of over-mitigation due to an assumption of non-competitiveness is significantly less than the risk of under-mitigation that would result from assuming the competitiveness of transmission constraints for purposes of exceptional dispatch mitigation.

c. It Is Just and Reasonable To Evaluate Path 15 and Path 26 as Part of the Default Competitive Path Assessment Process.

As noted above, the ISO will evaluate Path 15 and Path 26 as part of the default competitive path assessment using the ten-hour and 75-percent criteria. However, unlike all other constraints, the ISO will assume that transmission constraints relating to Path 15 and Path 26 are competitive unless the transmission constraint was deemed competitive in *fewer* than 75 percent of the instances in which the transmission constraint was binding when tested.[73]

It is just and reasonable to test Path 15 and Path 26 for competitiveness under the default competitive path assessment, instead of automatically deeming them to be competitive as is currently done under the ISO tariff.[74] The methodology for determining default competitive path designations derives from the methodology for making dynamic competitive path assessments, which tests all constraints to determine whether they are competitive. It is appropriate to test these two paths under the dynamic competitive path assessment because the test positively identifies competitiveness given current

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[71] As explained below, an assumption of competitiveness is more reasonable with respect to Paths 15 and 26 because of their nature as major transmission interfaces.

[72] MSC Opinion at 6.

[73] Proposed ISO tariff sections 39.7.3.3, 39.7.3.4.

[74] *See* section I(A) of this transmittal letter.

market and operating conditions and does not rely on a more conservative set of assumptions necessary in the static competitive path assessment. Thus, a competitive supply of counter-flow to these paths will be evident under the dynamic test and the paths will test competitive unless current market and operating conditions dictate otherwise. The benefit of “grandfathering” these paths as competitive is diminished with the positive identification of local market power under current conditions afforded by the dynamic competitive path assessment. There is no reason to exclude Path 15 and Path 26, alone among all the transmission constraints, from being tested with this greater accuracy as part of the default competitive path assessment especially given the Commission’s acceptance of testing these constraints in the dynamic competitive path assessment as applied in the day-ahead market.

Although Path 15 and Path 26 will be tested for competitiveness under the default competitive path assessment, the test applicable to them appropriately presumes that they are competitive unless they are shown to be non-competitive. The presumption of competitiveness for Path 15 and Path 26 is just and reasonable because it recognizes that these transmission constraints connect larger zones that have been observed to be competitive for energy under normal market and operating conditions. This is reflected in the current static competitive path assessment where these two paths are deemed competitive without any testing. If the default presumption was not that these paths are competitive and Path 15 and Path 26 were treated the same as other transmission constraints, these two major inter-zonal interfaces would trigger mitigation of exceptional dispatch simply because they have not been sufficiently congested in the past 60 days.[75]

Further, as discussed above, the proposed ten-hour and 60-day thresholds under the default competitive path assessment represent a significant decrease compared with the thresholds under the static competitive path assessment, which will significantly reduce the frequency of constraints being deemed non-competitive simply by virtue of not meeting the thresholds. Therefore, applying the 10-day and 60-day thresholds will reduce the frequency of Path 15 and Path 26 being deemed non-competitive.

3. Stakeholder Comments

In the stakeholder process, some stakeholders proposed alternative methodologies for determining default competitive path designations. One proposed alternative was to perform an off-line study of each specific reason that an exceptional dispatch was made in real-time. However, the ISO determined that the data needed to apply this approach would not be reliably available, and even when it was available, the approach would be too difficult to apply.[76] The ISO is not required to use a more

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[75] Revised Draft Final Proposal on Default Competitive Path Designations at 10.

[76] *Id.* at 5-6.

complicated methodology when a simpler methodology produces just and reasonable results.[77]

Another proposed alternative was to deem transmission facilities associated with exceptional dispatches as either always competitive or always non-competitive, with little or no reevaluation. The ISO determined that this approach would result in blanket static designations that failed to recognize changes in market and market model conditions. In addition, deeming transmission facilities to always be competitive would inappropriately allow for the exercise of market power, while deeming transmission facilities to always be non-competitive would result in over-mitigation.[78] After considering each of the proposed alternatives, the ISO concluded that determining default competitive path designations based on historic data, as proposed in this stage two tariff amendment, was the just and reasonable approach it should take.

Some stakeholders expressed concerns regarding the frequency of the ISO's exceptional dispatch instructions and the automatic mitigation of exceptional dispatches issued to address non-modeled transmission constraints,[79] but ultimately came to recognize that these issues are beyond the scope of the proposed tariff amendments. The tariff revisions to allow the ISO to implement default competitive path designations will not create any new type of mitigated exceptional dispatch, change how the ISO mitigates exceptional dispatches to address non-modeled transmission constraints, or result in any increase in the amount of exceptional dispatch the ISO will perform pursuant to its existing tariff authority. Nevertheless, the ISO is mindful of the Commission's concerns about the ISO's use of exceptional dispatch and the Commission's directive to file an informational report by October 2013 that describes "the steps [the ISO] has taken to reduce its reliance on exceptional dispatch" during the previous 12 months.[80] Since 2009, the ISO has taken steps to reduce the frequency of exceptional dispatches, including making reductions of exceptional dispatches a 2012 corporate goal. In addition, the ISO has ranked highly a market design initiative to consider additional constraints, processes, or products to reduce exceptional dispatch for 2013.[81]

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[77] *See, e.g.*, *San Diego Gas & Electric Co.*, 127 FERC ¶ 61,250, at P 28 (2009).

[78] *Id.* at 6.

[79] December 6 Memorandum at 5. Under the current static competitive path assessment, non-modeled transmission constraints are considered non-competitive because they are not studied. Under the default competitive path assessment, non-modeled transmission constraints will also be considered as non-competitive because the proposed thresholds, as described below, will not be met. The ISO is committed to incorporating more transmission constraints to reduce the incidence of non-modeled constraints.

[80] *California Independent System Operator Corp.*, 141 FERC ¶ 61,069, at PP 43-45 (2012).

[81] December 6 Memorandum at 5.

F. Miscellaneous Revisions

In the LMPM stage one tariff amendment, the ISO modified a number of tariff provisions to refer to the market power mitigation process in place of the process it superseded, the market power mitigation – reliability requirement determination (sometimes called the MPM-RRD).[82] In this LMPM stage two tariff amendment, the ISO proposes similar modifications to the following provisions: tariff sections 8.6.2, 11.5.6.1, 11.5.6.2, 11.5.6.2.4, 31, 31.1, 31.3, 31.3.1.3, and 31.5.1.3, and the definitions of the terms *day-ahead market*, *reliability requirement determination*, and *RRD* set forth in Appendix A to the tariff.

The ISO also proposes to revise tariff section 39.7 to provide the updated numbers of the tariff sections that describe the local market power mitigation processes and to specify that those processes utilize default energy bids calculated pursuant to existing tariff section 39.7.1.

III. Effective Date and Request for Commission Order

The ISO requests that the Commission accept the tariff revisions contained in this filing to become effective as of May 1, 2013. In order to accommodate this requested effective date, the ISO respectfully requests that the Commission issue an order accepting the tariff revisions 60 days from the date of this filing, April 22, 2013. Issuance of a Commission order by this date is necessary to provide the ISO with sufficient time to implement the software in an orderly process and to adjust, if necessary, to any Commission directive.

IV. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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[82] See transmittal letter for the stage one tariff amendment at 14.

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V. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective scheduling coordinator service agreements under the ISO tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VI. Attachments

The following documents, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised ISO tariff sheets
Attachment B	ISO tariff revisions shown in black-line format
Attachment C	Q2 2012 Report on Market Issues and Performance (Aug. 14, 2012)
Attachment D	Assessment of the Impact of Proposed Local Market Power Mitigation Enhancements (Feb. 9, 2012)
Attachment E	Revised Draft Final Proposal – Dynamic Competitive Path Assessment (July 5, 2011)
Attachment F	Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 – Revised Draft Final Proposal (Oct. 30, 2012)
Attachment G	Market Surveillance Committee Opinion on Mitigation Measures for Exceptional Dispatch in Real-Time (Dec. 5, 2012)

Attachment H	ISO Governing Board memorandum and resolution regarding default competitive path assessments
Attachment I	List of key dates in the market power mitigation stakeholder process

VII. Conclusion

For the foregoing reasons, the Commission should issue an order by April 22, 2013 that accepts the proposed tariff revisions without modification, effective May 1, 2013.

Respectfully submitted,

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Attachment A – Clean Tariff

Local Market Power Mitigation Enhancements Phase 2

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

4.5.1.1.13 Resource Control Agreements

Each Scheduling Coordinator Applicant will register with the CAISO any resource it or any Affiliate that satisfies the criteria set forth in Section 4.5.1.1.12 controls through a Resource Control Agreement to which the Scheduling Coordinator Applicant and/or any Affiliate that satisfies the criteria set forth in Section 4.5.1.1.12 is a party. Each Scheduling Coordinator Applicant that is a party to a Resource Control Agreement, or that has any Affiliate that satisfies the criteria set forth in Section 4.5.1.1.12 and is a party to a Resource Control Agreement, will submit information regarding the Resource Control Agreement to the CAISO. These requirements will continue to apply after a Scheduling Coordinator Applicant becomes a Scheduling Coordinator. The applicable Business Practice Manual sets forth the procedures for registering a resource controlled through a Resource Control Agreement and for providing information regarding a Resource Control Agreement to the CAISO. Any utility subject to the jurisdiction of a Local Regulatory Authority is not obligated to disclose Resource Control Agreements entered into by an unregulated Affiliate unless the Resource Control Agreement is between the utility and the unregulated Affiliate. Such an unregulated Affiliate is not treated as an Affiliate of the utility for purposes of determining supply portfolios pursuant to Section 39.7.2.2.

4.5.1.2 Scheduling Coordinator's Ongoing Obligations After Certification

4.5.1.2.1 Scheduling Coordinator's Obligation to Report Changes

4.5.1.2.1.1 Obligation to Report a Change in Filed Information

Each Scheduling Coordinator has an ongoing obligation to inform the CAISO of any changes to any of the information submitted by it to the CAISO as part of the application process including, but not limited to, any changes to the information requested by the CAISO, any changes in its credit ratings, any changes regarding its Affiliates that satisfy the requirements of Section 4.5.1.1.12, any changes regarding resources controlled through Resource Control Agreements that satisfy the requirements of Section 4.5.1.1.13, and any changes to information regarding a Resource Control Agreement provided pursuant to Section 4.5.1.1.13. The applicable Business Practice Manual sets forth the procedures for changing the Scheduling Coordinator's information and the timing of notifying the CAISO of such changes.

* * *

8.6.2 Right To Self-Provide

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve obligations in the IFM, and, to the extent needed to satisfy the CAISO's additional requirement, HASP and the Real-Time Market, from resources eligible for self-provision, as may be permissible for any given Ancillary Service in these respective markets. The right to self-provide Ancillary Services from capacity that is under a contractual obligation to provide Energy, including but not limited to capacity subject to an RMR Contract and local Resource Adequacy Resources, shall be conditional; self-provision of Ancillary Services from such capacity will only be permitted to the extent that capacity is not needed for Energy as a result of the MPM process described in this CAISO Tariff. To self-provide Ancillary Services a Scheduling Coordinator must provide the CAISO with a Submission to Self-Provide an Ancillary Service. Both Ancillary Service Bids and Submissions to Self-Provide an Ancillary Service can be provided to the CAISO for the same Ancillary Service and for the same hour in the same market. To the extent the Submission to Self-Provide an Ancillary Service is from a resource that is a Partial Resource Adequacy Resource, and Energy is needed, including for purposes under Section 31.3.1.3, from that resource the CAISO shall only disqualify the self-provision of Ancillary Services from the portion of the resource's capacity that has must-offer obligation, provided that the Scheduling Coordinator has not submitted an Energy Bid for the capacity that is not subject to a must-offer obligation. The CAISO will treat resources subject to Resource Adequacy requirements consistently with and such resources must comply with the bidding requirements in Section 40.6. If there is an Energy Bid submitted for the capacity of a Partial Resource Adequacy Resource that is not subject to a must-offer obligation the CAISO may disqualify the Submission to Self-Provide an Ancillary Service for the portion of the resources capacity that is not under a must-offer obligation consistent with the principles of co-optimization under the CAISO Tariff.

Prior to evaluating Ancillary Service Bids, the CAISO will determine whether Submissions to Self-Provide Ancillary Services are feasible with regard to resource operating characteristics and regional constraints and are qualified to provide the Ancillary Services in the markets for which they were submitted.

If the total Submissions to Self-Provide Ancillary Services exceed the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region, the submissions that would otherwise be accepted by the CAISO as feasible and qualified will be awarded on a pro-rata basis among the suppliers offering to self-provide the Ancillary Service up to the amount of the Ancillary Services requirement. If a regional constraint imposes a limit on the total amount of Regulation Up, Spinning Reserve, and Non-Spinning Reserve, and the total self-provision of these Ancillary Services in that region exceeds that limit, Self-Provided AS are qualified pro rata from higher to lower quality service in three tiers: Regulation Up first, followed by Spinning Reserve, and then by Non-Spinning Reserve. Submissions to Self-Provide Ancillary Services in excess of the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region will not be accepted and qualified by the CAISO as Self-Provided Ancillary Services.

The CAISO shall schedule Self-Provided Ancillary Services to the extent qualified in the IFM, HASP, and the RTM and Dispatch Self-Provided Ancillary Services in the Real-Time. To the extent that a Scheduling Coordinator self-provides Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve, the CAISO shall correspondingly reduce the quantity of the Ancillary Services it procures from Bids submitted in the IFM, HASP, and the Real-Time Market. To the extent a Scheduling Coordinator's Self-Provided Ancillary Service for a particular Ancillary Service is greater than the Scheduling Coordinator's obligation for that particular Ancillary Service in a Settlement Interval, the Scheduling Coordinator will receive the user rate for the Self-Provided Ancillary Service for the amount of the Self-Provided Ancillary Service in excess of the Scheduling Coordinator's obligation.

Scheduling Coordinators may trade Ancillary Services so that any Scheduling Coordinator may reduce its Ancillary Services Obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator.

* * *

11.5.6.1 Settlement for IIE from Exceptional Dispatches used for System Emergency Conditions, for a Market Interruption, to Mitigate Overgeneration Conditions or to Prevent or Relieve Imminent System Emergencies

The Exceptional Dispatch Settlement price for incremental IIE that is delivered as a result of an Exceptional Dispatch for System Emergency conditions, for a Market Interruption, to mitigate

Overgeneration conditions, or to prevent or relieve an imminent System Emergency, including forced Start-Ups and Shut-Downs, is the higher of the (a) Resource-Specific Settlement Interval LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the Resource-Specific Settlement Interval LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid Cost in excess of the applicable LMP at the relevant Location is settled pursuant to Section 11.5.6.1.1. The Exceptional Dispatch Settlement price for decremental IIE that is delivered as a result of an Exceptional Dispatch Instruction for a Market Interruption, or to prevent or relieve a System Emergency is the minimum of (a) the Resource-Specific Settlement Interval LMP, (b) the Energy Bid price subject to Section 39.6.1.4, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All Energy costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

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11.5.6.2 Settlement of IIE from Exceptional Dispatches Caused by Modeling Limitations

The Exceptional Dispatch Settlement price for IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion as a result of a transmission-related modeling limitation in the FNM as described in Section 34.9.3 is the maximum of (a) the Resource-Specific Settlement Interval LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the Resource-Specific Settlement Interval LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of (a) the Resource-Specific Settlement Interval LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for decremental IIE associated with this type of Exceptional Dispatch are settled in two payments: (1) decremental Energy is first settled at the Resource-Specific Settlement Interval LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the decremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3.

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11.5.6.2.4 Exceptional Dispatches for Non-Transmission-Related Modeling Limitations

The Exceptional Dispatch Settlement price for incremental IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion that is not a result of a transmission-related modeling limitation in the FNM as described in Section 34.9.3 is the maximum of the (a) Resource-Specific Settlement Interval LMP, (b) Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All costs for incremental Energy for this type of Exceptional Dispatch will be included in the total IIE Settlement Amount described in Section 11.5.1.1. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of the (a) Resource-Specific Settlement Interval LMP, (b) Energy Bid Price, (c) or the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

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31. Day-Ahead Market

The DAM consists of the following functions performed in sequence: the MPM, IFM, and RUC. Scheduling Coordinators may submit Bids for Energy, Ancillary Services and RUC Capacity for an applicable Trading Day. The CAISO shall issue Schedules for all Supply and Demand, including Participating Load and Proxy Demand Resources, pursuant to their Bids as provided in this Section 31.

31.1 Bid Submission And Validation In The Day-Ahead Market

Bids, including Self-Schedules and Ancillary Services Bids, and Submissions to Self-Provide an Ancillary Service shall be submitted pursuant to the submission rules specified in Section 30. There is a single Bid submission in which Scheduling Coordinators' Bids are used for purposes of the DAM, which includes the MPM, the IFM and RUC. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days prior to the applicable Trading Day up to Market Close of the DAM for the applicable Trading Day. The CAISO will validate all Bids submitted to the DAM pursuant to the procedures set forth in Section 30.7. Scheduling Coordinators must submit Bids for participation in the IFM for Resource Adequacy Capacity as required in Section 40.

31.2 Day-Ahead MPM Process

After the Market Close of the DAM, and after the CAISO has validated the Bids pursuant to Section 30.7, the CAISO will perform the MPM process, which is a single market run that occurs prior to the IFM Market Clearing run. The Day-Ahead MPM process determines which Bids need to be mitigated in the IFM and when RMR Proxy Bids should be considered in the IFM for RMR Units. The Day-Ahead MPM process optimizes resources to meet Demand reflected in Demand Bids, including Export Bids and Virtual Demand Bids, and to procure one hundred (100) percent of Ancillary Services requirements based on Supply Bids submitted to the DAM. Virtual Bids and Bids from Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process, but are not subject to Bid mitigation. Bids from Participating Load resources that are not subject to Bid mitigation will also be considered in the MPM process. The mitigated or unmitigated Bids and RMR Proxy Bids identified in the MPM process for all resources that cleared in the MPM are then passed to the IFM. The CAISO performs the MPM process for the DAM for the twenty-four (24) hours of the targeted Trading Day.

* * *

31.3 Integrated Forward Market

After the MPM and prior to RUC, the CAISO shall perform the IFM. The IFM (1) performs Unit Commitment and Congestion Management (2) clears mitigated or unmitigated Bids cleared in the MPM as well as Bids that were not cleared in the MPM process against bid-in Demand, taking into account transmission limits and honoring technical and inter-temporal operating constraints, such as Minimum Run Times (3) and procures Ancillary Services to meet one hundred (100) percent of the CAISO Forecast of CAISO Demand requirements. The IFM utilizes a set of integrated programs that: (1) determine Day-Ahead Schedules and AS Awards, and related LMPs and ASMPs; and (2) optimally commits resources that are bid in to the DAM. The IFM utilizes a SCUC algorithm that optimizes Start-Up Costs, Minimum Load Costs, Transition Costs, and Energy Bids along with any Bids for Ancillary Services as well as Self-Schedules submitted by Scheduling Coordinators. The IFM selects the optimal MSG Configuration from a maximum of ten MSG Configurations of each Multi-Stage Generating Resource as mutually exclusive resources. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, the IFM will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration. The IFM also provides for the optimal management of Use-Limited Resources. The ELS Resources committed through the ELC Process conducted two days before the day the IFM process is conducted for the next Trading Day as described in Section 31.7 are binding.

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31.3.1.3 Reduction of Self-Scheduled LAP Demand

In the IFM, to the extent the market software cannot resolve a non-competitive Transmission Constraint utilizing Effective Economic Bids such that self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-priced Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-priced Quantity to be adjusted, will be: (a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM process.

(b) Relax the constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

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31.5.1.3 RMR Generation Resources

If a resource is determined to have an RMR Generation requirement for any Trading Hour of the next day, either by the MPM process or by the CAISO through a manual RMR Dispatch Notice, and if any portion of the RMR Generation requirement has not been cleared in the IFM, the entire portion of the

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33.4 MPM For The HASP

After the Market Close of the HASP and RTM, after the CAISO has validated the Bids pursuant to Section 30.7, and prior to running the HASP optimization, the CAISO conducts the MPM process, the results of which will be utilized in the HASP optimization. Bids on behalf of Demand Response Resources, Participating Load and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process for the HASP produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated in the HASP is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3 above. If a Bid is mitigated in any of the four fifteen (15) minute intervals comprising a Trading Hour during the MPM process for the HASP, then that Bid will be treated as mitigated for the entire Trading Hour for purposes of the HASP optimization. A single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level.

For RMR Units, RMR Proxy Bids resulting from the HASP MPM process, will be utilized in both the HASP optimization and all RTM processes for each Trading Hour. For a Condition 1 RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.2 above. If a Condition 2 RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 RMR Units, when mitigation is triggered, a single RMR Proxy Bid for the entire Trading Hour is calculated using the same methodology described above for non-RMR Units. For a Condition 1 RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the RMR Unit's Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 RMR Units may be issued manual RMR dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

* * *

34.2 Real-Time Unit Commitment

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every fifteen (15) minutes to: (1) make commitment decisions for Fast Start and Short Start Units having Start-Up Times within the applicable time periods described below in this section, and (2) procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity for the next fifteen-minute Real-Time Ancillary Service interval. In any fifteen (15) minute RTUC interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide Ancillary

Services in RTM. For Multi-Stage Generating Resources the RTUC will issue a binding Transition Instruction separately from the binding Start-Up or Shut Down instructions. The RTUC can also be run with the Contingency Flag activated, in which case the RTUC can commit Contingency Only Operating Reserves. If RTUC is run without the Contingency Flag activated, it cannot commit Contingency Only Operating Reserves. RTUC is run at the following time intervals: (1) at approximately 7.5 minutes prior to the next Trading Hour, in conjunction with the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes where T is the beginning of the next Trade Hour. The HASP, described in Section 33, is a special RTUC run that is performed at approximately 67.5 minutes before each Trading Hour and has the additional responsibility of pre-dispatching Energy and awarding Ancillary Services for hourly dispatched System Resources. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the RTUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * *

34.2.3 MPM For The Real-Time Market

The CAISO performs the MPM for the Real-Time Market using validated Bids for the applicable Trading Hour pursuant to Section 30.7 as part of each RTUC. Bids on behalf of Demand Response Resources, Participating Load and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process described in this Section 34.2.3 calculates mitigated Bids for use in the following Real-Time Market applications: the STUC, the RTUC and the Real-Time Dispatch. The determination as to whether a Bid is mitigated in this process is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3. If a Bid is mitigated in the MPM process for the first fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized for all market applications for that first fifteen (15) minute interval. If a Bid is not mitigated in the first fifteen (15) minute interval, it is subject to mitigation in subsequent fifteen (15) minute intervals of the Trading Hour as determined in the MPM runs for the subsequent intervals. For each Trading Hour, any Bid mitigated in a prior fifteen (15) minute interval of that Trading Hour will continue to be mitigated in subsequent intervals of that Trading Hour and may be further mitigated as determined in the MPM runs for any subsequent fifteen (15) minute interval.

* * *

39.7 Local Market Power Mitigation For Energy Bids

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM, Section 33.4 for the HASP, and Section 34.2.3 for the RTM utilizing Default Energy Bids calculated pursuant to one of the options set forth in Section 39.7.1.

* * *

39.7.2 Competitive Path Designation

39.7.2.1 Timing of Assessments

For the DAM, HASP, and RTM, the CAISO will make assessments and designations of whether Transmission Constraints are competitive or non-competitive as part of the MPM runs associated with the DAM, HASP, and RTM, respectively. Only binding Transmission Constraints determined by the MPM process will be assessed in the applicable market.

39.7.2.2 Criteria

Subject to Section 39.7.3, for the DAM, HASP, and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the DAM – As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

(b) <u>Transmission Constraints for the HASP and RTM</u> – As part of the MPM processes associated with the HASP and RTM, the CAISO will designate a Transmission Constraint for the HASP or RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the HASP (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the HASP, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the HASP, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the HASP. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the

Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the HASP (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the HASP, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

39.7.3 Default Competitive Path Designations

The CAISO will maintain default competitive path designation sets for the Day-Ahead Market and for the HASP/Real-Time Market, which the CAISO will use in order to determine the competitiveness or non-competitiveness of Transmission Constraints under two circumstances: (1) in the event of a failure of the CAISO Markets software to perform an assessment of whether Transmission Constraints are competitive or non-competitive pursuant to Section 39.7.2; and (2) in order to determine whether Exceptional

Dispatches are related to a non-competitive Transmission Constraint for purposes of mitigation of Exceptional Dispatches of resources under Section 39.10(1). Default competitive path designations will be determined pursuant to the methodology set forth in this Section 39.7.3 and will be updated no less frequently than once every seven (7) days. Until the CAISO has developed sufficient information to develop default competitive path designations, the CAISO will continue to utilize the most recent list of competitive path designations determined prior to the effective date of this tariff provision.

39.7.3.1 Methodology for Determining Day-Ahead Default Competitive Path Designations for Transmission Constraints Other Than Path 15 and Path 26 Transmission Constraints

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested. These calculations will be made utilizing data from the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.1(1) and 39.7.3.1(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.2 Methodology for Determining HASP/RTM Default Competitive Path Designations for Transmission Constraints Other Than Path 15 and Path 26 Transmission Constraints

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the HASP/RTM only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.2(1) and 39.7.3.2(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.3 Methodology for Determining Day-Ahead Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.3(1) and 39.7.3.3(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.4 Methodology for Determining HASP/RTM Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the HASP/RTM unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.4(1) and 39.7.3.4(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

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Appendix A
Master Definition Supplement

- Day-Ahead Market (DAM)

A series of processes conducted in the Day-Ahead that includes the Market Power Mitigation, the Integrated Forward Market and the Residual Unit Commitment.

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- Resource Control Agreement

An agreement that gives an entity bidding, scheduling, and/or operational control over a physical resource owned by or under contract to another entity, or otherwise directs the manner in which such a resource participates in the CAISO markets. A Resource Control Agreement includes but is not limited to any agreement under which an entity controls a resource that uses a Scheduling Coordinator ID Code assigned to a Scheduling Coordinator that is not an Affiliate of the controlling entity.

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Attachment B – Marked Tariff

Local Market Power Mitigation Enhancements Phase 2 – Tariff Amendment

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

4.5.1.1.13 Resource Control Agreements

Each Scheduling Coordinator Applicant will register with the CAISO any resource it or any Affiliate that satisfies the criteria set forth in Section 4.5.1.1.12 controls through a Resource Control Agreement to which the Scheduling Coordinator Applicant and/or any Affiliate that satisfies the criteria set forth in Section 4.5.1.1.12 is a party. Each Scheduling Coordinator Applicant that is a party to a Resource Control Agreement, or that has any Affiliate that satisfies the criteria set forth in Section 4.5.1.1.12 and is a party to a Resource Control Agreement, will submit information regarding the Resource Control Agreement to the CAISO. These~~is~~ requirements will continue to apply after a Scheduling Coordinator Applicant becomes a Scheduling Coordinator. The applicable Business Practice Manual sets forth the procedures for registering a resource controlled through a Resource Control Agreement and for providing information regarding a Resource Control Agreement to the CAISO. Any utility subject to the jurisdiction of a Local Regulatory Authority is not obligated to disclose Resource Control Agreements entered into by an unregulated Affiliate unless the Resource Control Agreement is between the utility and the unregulated Affiliate. Such an unregulated Affiliate is not treated as an Affiliate~~s~~ of the utility for purposes of determining supply portfolios pursuant to Section 39.7.2.2.

4.5.1.2 Scheduling Coordinator's Ongoing Obligations After Certification

4.5.1.2.1 Scheduling Coordinator's Obligation to Report Changes

4.5.1.2.1.1 Obligation to Report a Change in Filed Information

Each Scheduling Coordinator has an ongoing obligation to inform the CAISO of any changes to any of the information submitted by it to the CAISO as part of the application process including, but not limited to, any changes to the information requested by the CAISO, any changes in its credit ratings, any changes regarding its Affiliates that satisfy the requirements of Section 4.5.1.1.12, ~~and~~ any changes regarding resources controlled through Resource Control Agreements that satisfy the requirements of Section 4.5.1.1.13, and any changes to information regarding a Resource Control Agreement provided pursuant to Section 4.5.1.1.13. The applicable Business Practice Manual sets forth the procedures for changing the Scheduling Coordinator's information and the timing of notifying the CAISO of such changes.

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8.6.2 Right To Self-Provide

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve obligations in the IFM, and, to the extent needed to satisfy the CAISO's additional requirement, HASP and the Real-Time Market, from resources eligible for self-provision, as may be permissible for any given Ancillary Service in these respective markets. The right to self-provide Ancillary Services from capacity that is under a contractual obligation to provide Energy, including but not limited to capacity subject to an RMR Contract and local Resource Adequacy Resources, shall be conditional; self-provision of Ancillary Services from such capacity will only be permitted to the extent that capacity is not needed for Energy as a result of the MPM~~-RRD~~ process described in this CAISO Tariff. To self-provide Ancillary Services a Scheduling Coordinator must provide the CAISO with a Submission to Self-Provide an Ancillary Service. Both Ancillary Service Bids and Submissions to Self-Provide an Ancillary Service can be provided to the CAISO for the same Ancillary Service and for the same hour in the same market. To the extent the Submission to Self-Provide an Ancillary Service is from a resource that is a Partial Resource Adequacy Resource, and Energy is needed, including for purposes under Section 31.3.1.3, from that resource the CAISO shall only disqualify the self-provision of Ancillary Services from the portion of the resource's capacity that has must-offer obligation, provided that the Scheduling Coordinator has not submitted an Energy Bid for the capacity that is not subject to a must-offer obligation. The CAISO will treat resources subject to Resource Adequacy requirements consistently with and such resources must comply with the bidding requirements in Section 40.6. If there is an Energy Bid submitted for the capacity of a Partial Resource Adequacy Resource that is not subject to a must-offer obligation the CAISO may disqualify the Submission to Self-Provide an Ancillary Service for the portion of the resources capacity that is not under a must-offer obligation consistent with the principles of co-optimization under the CAISO Tariff.

Prior to evaluating Ancillary Service Bids, the CAISO will determine whether Submissions to Self-Provide Ancillary Services are feasible with regard to resource operating characteristics and regional constraints and are qualified to provide the Ancillary Services in the markets for which they were submitted.

If the total Submissions to Self-Provide Ancillary Services exceed the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region, the submissions that would otherwise be accepted by the CAISO as feasible and qualified will be awarded on a pro-rata basis among the suppliers offering to self-provide the Ancillary Service up to the amount of the Ancillary Services requirement. If a regional constraint imposes a limit on the total amount of Regulation Up, Spinning Reserve, and Non-Spinning Reserve, and the total self-provision of these Ancillary Services in that region exceeds that limit, Self-Provided AS are qualified pro rata from higher to lower quality service in three tiers: Regulation Up first, followed by Spinning Reserve, and then by Non-Spinning Reserve. Submissions to Self-Provide Ancillary Services in excess of the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region will not be accepted and qualified by the CAISO as Self-Provided Ancillary Services.

The CAISO shall schedule Self-Provided Ancillary Services to the extent qualified in the IFM, HASP, and the RTM and Dispatch Self-Provided Ancillary Services in the Real-Time. To the extent that a Scheduling Coordinator self-provides Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve, the CAISO shall correspondingly reduce the quantity of the Ancillary Services it procures from Bids submitted in the IFM, HASP, and the Real-Time Market. To the extent a Scheduling Coordinator's Self-Provided Ancillary Service for a particular Ancillary Service is greater than the Scheduling Coordinator's obligation for that particular Ancillary Service in a Settlement Interval, the Scheduling Coordinator will receive the user rate for the Self-Provided Ancillary Service for the amount of the Self-Provided Ancillary Service in excess of the Scheduling Coordinator's obligation.

Scheduling Coordinators may trade Ancillary Services so that any Scheduling Coordinator may reduce its Ancillary Services Obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator.

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11.5.6.1 Settlement for IIE from Exceptional Dispatches used for System Emergency Conditions, for a Market Interruption, to Mitigate Overgeneration Conditions or to Prevent or Relieve Imminent System Emergencies

The Exceptional Dispatch Settlement price for incremental IIE that is delivered as a result of an Exceptional Dispatch for System Emergency conditions, for a Market Interruption, to mitigate

Overgeneration conditions, or to prevent or relieve an imminent System Emergency, including forced Start-Ups and Shut-Downs, is the higher of the (a) Resource-Specific Settlement Interval LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM~~-RRD~~ in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the Resource-Specific Settlement Interval LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid Cost in excess of the applicable LMP at the relevant Location is settled pursuant to Section 11.5.6.1.1. The Exceptional Dispatch Settlement price for decremental IIE that is delivered as a result of an Exceptional Dispatch Instruction for a Market Interruption, or to prevent or relieve a System Emergency is the minimum of (a) the Resource-Specific Settlement Interval LMP, (b) the Energy Bid price subject to Section 39.6.1.4, (c) the Default Energy Bid price if the resource has been mitigated through the MPM~~-RRD~~ in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All Energy costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

* * *

11.5.6.2 Settlement of IIE from Exceptional Dispatches Caused by Modeling Limitations

The Exceptional Dispatch Settlement price for IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion as a result of a transmission-related modeling limitation in the FNM as described in Section 34.9.3 is the maximum of (a) the Resource-Specific Settlement Interval LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM~~-RRD~~ in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the Resource-Specific Settlement Interval LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of (a) the Resource-Specific Settlement Interval LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM~~-RRD~~ in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for decremental IIE associated with this type of Exceptional Dispatch are settled in two payments: (1) decremental Energy is first settled at the Resource-Specific Settlement Interval LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the decremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3.

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11.5.6.2.4 Exceptional Dispatches for Non-Transmission-Related Modeling Limitations

The Exceptional Dispatch Settlement price for incremental IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion that is not a result of a transmission-related modeling limitation in the FNM as described in Section 34.9.3 is the maximum of the (a) Resource-Specific Settlement Interval LMP, (b) Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM~~-RRD~~ in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All costs for incremental Energy for this type of Exceptional Dispatch will be included in the total IIE Settlement Amount described in Section 11.5.1.1. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of the (a) Resource-Specific Settlement Interval LMP, (b) Energy Bid Price, (c) or the Default Energy Bid price if the resource has been mitigated through the MPM~~-RRD~~ in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

* * *

31. Day-Ahead Market

The DAM consists of the following functions performed in sequence: the MPM~~-RRD~~, IFM, and RUC. Scheduling Coordinators may submit Bids for Energy, Ancillary Services and RUC Capacity for an applicable Trading Day. The CAISO shall issue Schedules for all Supply and Demand, including Participating Load and Proxy Demand Resources, pursuant to their Bids as provided in this Section 31.

31.1 Bid Submission And Validation In The Day-Ahead Market

Bids, including Self-Schedules and Ancillary Services Bids, and Submissions to Self-Provide an Ancillary Service shall be submitted pursuant to the submission rules specified in Section 30. There is a single Bid submission in which Scheduling Coordinators' Bids are used for purposes of the DAM, which includes the MPM~~-RRD~~, the IFM and RUC. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days prior to the applicable Trading Day up to Market Close of the DAM for the applicable Trading Day. The CAISO will validate all Bids submitted to the DAM pursuant to the procedures set forth in Section 30.7. Scheduling Coordinators must submit Bids for participation in the IFM for Resource Adequacy Capacity as required in Section 40.

31.2 Day-Ahead MPM Process

After the Market Close of the DAM, and after the CAISO has validated the Bids pursuant to Section 30.7, the CAISO will perform the MPM process, which is a single market run that occurs prior to the IFM Market Clearing run. The Day-Ahead MPM process determines which Bids need to be mitigated in the IFM and when RMR Proxy Bids should be considered in the IFM for RMR Units. The Day-Ahead MPM process optimizes resources to meet Demand reflected in Demand Bids, including Export Bids and Virtual Demand Bids, and to procure one hundred (100) percent of Ancillary Services requirements based on Supply Bids submitted to the DAM. Virtual Bids and Bids from Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process, but are not subject to Bid mitigation. Bids from Participating Load resources that are not subject to Bid mitigation will also be considered in the MPM process. The mitigated or unmitigated Bids and RMR Proxy Bids identified in the MPM process for all resources that cleared in the MPM are then passed to the IFM. The CAISO performs the MPM process for the DAM for the twenty-four (24) hours of the targeted Trading Day.

* * *

31.3 Integrated Forward Market

After the MPM~~-RRD~~ and prior to RUC, the CAISO shall perform the IFM. The IFM (1) performs Unit Commitment and Congestion Management (2) clears mitigated or unmitigated Bids cleared in the MPM~~-RRD~~ as well as Bids that were not cleared in the MPM~~-RRD~~ process against bid-in Demand, taking into account transmission limits and honoring technical and inter-temporal operating constraints, such as Minimum Run Times (3) and procures Ancillary Services to meet one hundred (100) percent of the CAISO Forecast of CAISO Demand requirements. The IFM utilizes a set of integrated programs that: (1) determine Day-Ahead Schedules and AS Awards, and related LMPs and ASMPs; and (2) optimally commits resources that are bid in to the DAM. The IFM utilizes a SCUC algorithm that optimizes Start-Up Costs, Minimum Load Costs, Transition Costs, and Energy Bids along with any Bids for Ancillary Services as well as Self-Schedules submitted by Scheduling Coordinators. The IFM selects the optimal MSG Configuration from a maximum of ten MSG Configurations of each Multi-Stage Generating Resource as mutually exclusive resources. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, the IFM will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration. The IFM also provides for the optimal management of Use-Limited Resources. The ELS Resources committed through the ELC Process conducted two days before the day the IFM process is conducted for the next Trading Day as described in Section 31.7 are binding.

* * *

31.3.1.3 Reduction of Self-Scheduled LAP Demand

In the IFM, to the extent the market software cannot resolve a non-competitive Transmission Constraint utilizing Effective Economic Bids such that self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-priced Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-priced Quantity to be adjusted, will be: (a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM~~-RRD~~ process.

(b) Relax the constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

* * *

31.5.1.3 RMR Generation Resources

If a resource is determined to have an RMR Generation requirement for any Trading Hour of the next day, either by the MPM~~-RRD~~ process or by the CAISO through a manual RMR Dispatch Notice, and if any portion of the RMR Generation requirement has not been cleared in the IFM, the entire portion of the

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33.4 MPM For The HASP~~ And The RTM~~

After the Market Close of the HASP and RTM, after the CAISO has validated the Bids pursuant to ~~s~~Section 30.7, and prior to running the HASP optimization, the CAISO conducts the MPM process, the results of which will be utilized in the HASP optimization~~ and all RTM processes for the Trading Hour~~. Bids on behalf of Demand Response Resources, Participating Load and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process for the HASP ~~and RTM~~ produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated in the HASP ~~and RTM~~ is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3 above. If a Bid is mitigated in any of the four fifteen (15) minute intervals comprising a Trading Hour during the MPM process for the HASP~~ and RTM~~, then that Bid will be treated as mitigated for the entire Trading Hour for purposes of the HASP optimization~~ and all RTM~~

~~processes~~. A single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level.

For RMR Units, RMR Proxy Bids resulting from the HASP MPM process will be utilized in both the HASP optimization and all RTM processes for each Trading Hour. For a Condition 1 RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.2 above. If a Condition 2 RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 RMR Units, when mitigation is triggered, a single RMR Proxy Bid for the entire Trading Hour is calculated using the same methodology described above for non-RMR Units. For a Condition 1 RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the RMR Unit's Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 RMR Units may be issued manual RMR dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

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34.2 Real-Time Unit Commitment

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every fifteen (15) minutes to: (1) make commitment decisions for Fast Start and Short Start Units having Start-Up Times within the applicable time periods described below in this section, and (2) procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity for the next fifteen-minute Real-Time Ancillary Service interval. In any fifteen (15) minute RTUC interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide Ancillary

Services in RTM. For Multi-Stage Generating Resources the RTUC will issue a binding Transition Instruction separately from the binding Start-Up or Shut Down instructions. The RTUC can also be run with the Contingency Flag activated, in which case the RTUC can commit Contingency Only Operating Reserves. If RTUC is run without the Contingency Flag activated, it cannot commit Contingency Only Operating Reserves. RTUC is run at the following time intervals: (1) at approximately 7.5 minutes prior to the next Trading Hour, in conjunction with the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes where T is the beginning of the next Trade Hour. The HASP, described in Section 33, is a special RTUC run that is performed at approximately 67~~7~~.5 minutes before each Trading H~~h~~our and has the additional responsibility of ~~: (1)~~ pre-dispatching Energy and awarding Ancillary Services for hourly dispatched System Resources. ~~for the Trading Hour that begins 67.5 minutes later, and (2) performing the necessary MPM for that Trading Hour.~~ A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource’s derate or outages, will be reconsidered in the RTUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

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34.2.3 MPM For The Real-Time Market

The CAISO performs the MPM for the Real-Time Market using validated Bids for the applicable Trading Hour pursuant to Section 30.7 as part of each RTUC. Bids on behalf of Demand Response Resources, Participating Load and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process described in this Section 34.2.3 calculates mitigated Bids for use in the following Real-Time Market applications: the STUC, the RTUC and the Real-Time Dispatch. The determination as to whether a Bid is mitigated in this process is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3. If a Bid is mitigated in the MPM process for the first fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized for all market applications for that first fifteen (15) minute interval. If a Bid is not mitigated in the first fifteen (15) minute interval, it is subject to mitigation in subsequent fifteen (15) minute intervals of the Trading Hour as determined in the MPM runs for the subsequent intervals. For each Trading Hour, any Bid mitigated in a prior fifteen (15) minute interval of that Trading Hour will continue to be mitigated in subsequent intervals of that Trading Hour and may be further mitigated as determined in the MPM runs for any subsequent fifteen (15) minute interval.

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39.7 Local Market Power Mitigation For Energy Bids

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2.~~ Prior to the effective date of this tariff provision, assessments will be performed for use in the DAM, HASP and the RTM at a minimum four (4) times per year and potentially more frequently if needed due to changes in system conditions, network topology, or market performance. Any changes in Transmission Constraints designations will be publicly noticed prior to making the change. Upon determination that an ad hoc assessment is warranted, the CAISO will notice Market Participants that such an assessment will be performed. As of the effective date of this tariff provision, these procedures will only apply to assessments and designations of Transmission Constraints as competitive or non-competitive used in the HASP and RTM, while assessments and designations of Transmission Constraints as competitive or non-competitive for the DAM will be made as part of each MPM run associated with the DAM.~~ The local market power mitigation processes are described ~~determination whether a unit is being dispatched to relieve Congestion on a competitive or non-competitive Transmission Constraint is based on a preliminary market run that is performed prior to the actual pricing run of the market, as described ~~in Section~~s~~ 31.2~~ and 33~~ for the DAM, Section 33.4 for the HASP, and Section 34.2.3 for the RTM~~, respectively~~ utilizing Default Energy Bids calculated pursuant to one of the options set forth in Section 39.7.1.

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39.7.2 Competitive Path Designation

39.7.2.1 Timing of Assessments

For the DAM, HASP, and RTM, the CAISO will make assessments and designations of whether Transmission Constraints are competitive or non-competitive as part of ~~each~~the MPM runs associated with the DAM, HASP, and RTM, respectively. Only binding Transmission Constraints determined by the ~~Day-Ahead~~ MPM process will be assessed in the applicable market.~~DAM.~~

~~For the HASP and RTM, the CAISO may perform additional competitive constraint assessments during the year if changes in transmission infrastructure, generation resources, or Load, in the CAISO Balancing Authority Area and adjacent Balancing Authority Areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes. The CAISO will calculate and post path designations for the HASP and RTM not less than four (4) times each year thereafter to provide timely seasonal path designations.~~

39.7.2.2 Criteria

Subject to Section 39.7.3, ~~F~~for the DAM, HASP, and RTM, a Transmission Constraint will be non-competitive only if ~~by default unless the CAISO designates~~ the Transmission Constraint fails the dynamic competitive path assessment ~~as non-competitive~~ pursuant to this Section 39.7.2.2. ~~For the HASP and RTM, a Transmission Constraint will be non-competitive by default unless the CAISO designates the Transmission Constraint as competitive pursuant to this Section 39.7.2.2.~~

(a) Transmission Constraints for the DAM – As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means~~includes~~ all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means~~is~~ any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month ~~(12)~~ period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

(b) Transmission Constraints for the HASP and RTM – As part of the MPM processes associated with the HASP and RTM, the CAISO will designate a Transmission Constraint for the HASP or RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect~~s~~ the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the HASP (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the HASP, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the HASP, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the HASP. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to

Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the HASP (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the HASP, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

~~(b) Transmission Constraints for the HASP and RTM – A Transmission Constraint for the HASP or RTM will be deemed competitive if no three (3) unaffiliated suppliers are jointly pivotal in relieving Congestion on that constraint. The determination of whether or not the pivotal supplier criteria for an individual Transmission Constraint for the HASP or RTM are violated will be assessed using the Feasibility Index described in Section 39.7.2.4. Assessment of competitiveness for the HASP or RTM will be performed assuming various system conditions potentially including but not limited to season, load, planned transmission and resource outages. If an individual Transmission Constraint for the HASP or RTM fails the pivotal supplier criteria under any of these system conditions, the Transmission Constraint will be deemed uncompetitive until a subsequent assessment deems the Transmission Constraint competitive. In general, a constraint for the HASP or~~

~~RTM may be an individual transmission line or a collection of lines that create a distinct Transmission Constraint. For purposes of the competitive assessment for the HASP or RTM, the set of Transmission Constraints that will be included in the FNM are those modeled along with Transmission Constraints expected to be enforced in clearing the CAISO Markets.~~

~~39.7.2.3 Candidate Path Identification~~

~~Assessments of competitive Transmission Constraints for the HASP or RTM will consider all interfaces to neighboring Balancing Authority Areas and all inter-zonal interfaces that predate the effective date of this provision to be competitive, and no such interfaces will be included in the set of candidate Transmission Constraints for assessment. The set of candidate Transmission Constraints for the HASP or RTM will be reduced to those remaining Transmission Constraints that were congested or managed for Congestion in greater than five hundred (500) hours in the prior twelve (12) months.~~

~~39.7.2.4 Feasibility Index~~

~~For the HASP or RTM, the CAISO will perform a pivotal supplier test on all suppliers in the CAISO Balancing Authority Area for each path to be assessed using the Feasibility Index (FI). Suppliers will be considered in two groups: those suppliers with the largest portfolios will be considered in the preliminary simulations, and any additional suppliers who are likely to be pivotal given the competitive designations from the preliminary simulations. The FI requires solving the FNM having removed all internal resources of a supplier and modifying the candidate constraints of the FNM such that the flow limits of the set of candidate constraints can be exceeded with a penalty imposed for excess flow. The resulting solution to the FNM produces constraint flows that can be used to calculate the FI. The FI is calculated for each constraint as the proportion of the Transmission Constraint limit that is exceeded to solve the FNM without the specified supplier's supply. FI values less than zero indicate the supplier is pivotal in relieving Congestion on the specified constraint. The process is repeated by removing the supply portfolio of two and three suppliers for paths with non-negative FI. If any three suppliers are jointly pivotal in relieving Congestion on a candidate path, as indicated by an FI value less than zero, the candidate path will be deemed uncompetitive. Otherwise, the candidate path will be deemed competitive. The portfolio of each supplier will be based on ownership information available to the CAISO, taking into account any material~~

~~transfer of sufficient length that the transfer of control could have persistent impact on the relative shares of supply within the CAISO Balancing Authority Area. These transfers of control will be utilized in the assessment as provided to the CAISO by the supplier reflecting its triennial filing with FERC for market-based rate authority.~~

39.7.3 Default Competitive Path Designations

The CAISO will maintain default competitive path designation sets for the Day-Ahead Market and for the HASP/Real-Time Market, which the CAISO will use in order to determine the competitiveness or non-competitiveness of Transmission Constraints under two circumstances: (1) in the event of a failure of the CAISO Markets software to perform an assessment of whether Transmission Constraints are competitive or non-competitive pursuant to Section 39.7.2; and (2) in order to determine whether Exceptional Dispatches are related to a non-competitive Transmission Constraint for purposes of mitigation of Exceptional Dispatches of resources under Section 39.10(1). Default competitive path designations will be determined pursuant to the methodology set forth in this Section 39.7.3 and will be updated no less frequently than once every seven (7) days. Until the CAISO has developed sufficient information to develop default competitive path designations, the CAISO will continue to utilize the most recent list of competitive path designations determined prior to the effective date of this tariff provision.

39.7.3.1 Methodology for Determining Day-Ahead Default Competitive Path Designations for Transmission Constraints Other Than Path 15 and Path 26 Transmission Constraints

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.1(1) and 39.7.3.1(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.2 Methodology for Determining HASP/RTM Default Competitive Path Designations for Transmission Constraints Other Than Path 15 and Path 26 Transmission Constraints

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the HASP/RTM only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.2(1) and 39.7.3.2(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.3 Methodology for Determining Day-Ahead Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.3(1) and 39.7.3.3(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

39.7.3.4 Methodology for Determining HASP/RTM Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the HASP/RTM unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.4(1) and 39.7.3.4(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

* * *

Appendix A
Master Definition Supplement

- Day-Ahead Market (DAM)

A series of processes conducted in the Day-Ahead that includes the Market Power Mitigation ~~Reliability Requirement Determination~~, the Integrated Forward Market and the Residual Unit Commitment.

* * *

~~***- Reliability Requirement Determination (RRD)***~~

~~The reliability process conducted by the CAISO during the DAM, prior to the IFM, and in the HASP, prior to the RTUC, to determine whether unit(s) subject to a contract with the CAISO to provide local reliability services, which includes a Reliability Must-Run Contract and any successor instrument, are necessary to meet local reliability needs for the CAISO Balancing Authority Area.~~

* * *

- Resource Control Agreement

An agreement that gives an entity bidding, scheduling, and/or operational control over a physical resource owned by or under contract to another entity, or otherwise directs the manner in which such a resource participates in the CAISO markets. A Resource Control Agreement includes but is not limited to any agreement under which an entity controls a resource that uses a Scheduling Coordinator ID Code assigned to a Scheduling Coordinator that is not an Affiliate of the controlling entity.

~~***- RRD***~~

~~Reliability Requirement Determination~~

* * *

Attachment C –

Q2 2012 Report on Market Issues and Performance (Aug. 14, 2012)

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

California Independent System Operator Corporation

California ISO

Q2 2012 Report on Market Issues and Performance

August 14, 2012

Prepared by: Department of Market Monitoring

Table of Contents

Executive summary

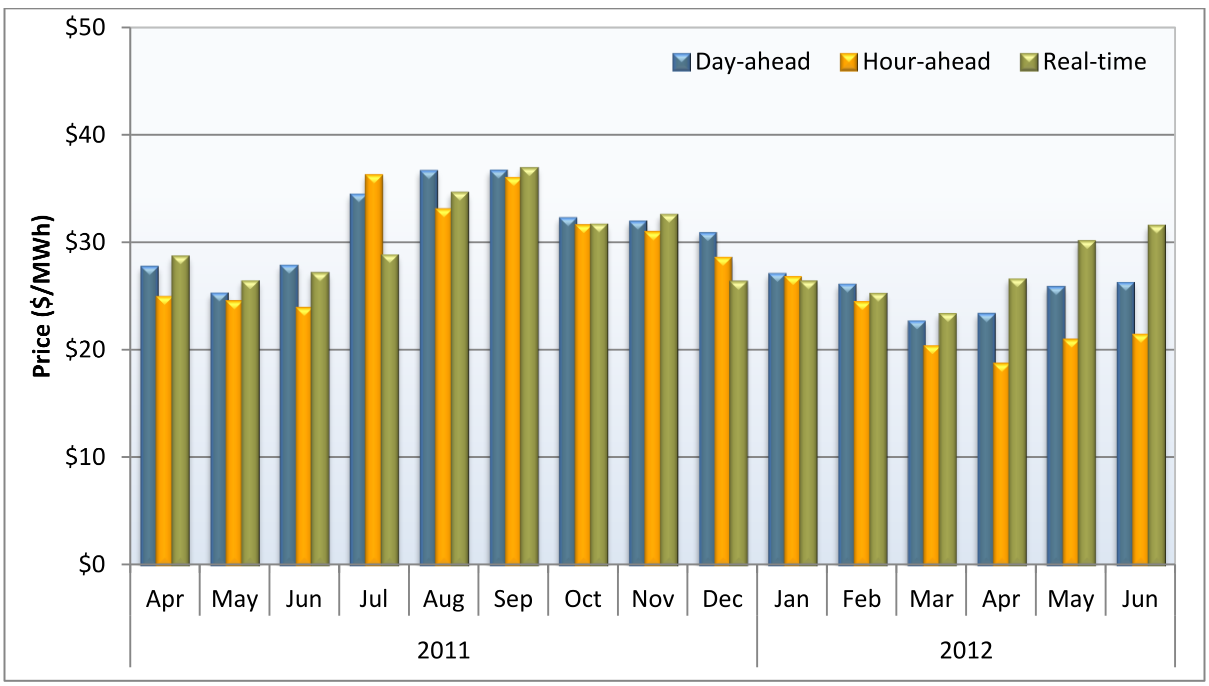
This report provides an overview of general market performance during the second quarter of 2012 (April – June) by the Department of Market Monitoring (DMM).

Energy market performance

- The day-ahead integrated forward market was stable and competitive. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions. Although real-time prices exceeded day-ahead prices in the second quarter, the real-time market continues to account for a very small portion of the wholesale market, so that overall market wholesale costs continue to be highly competitive.

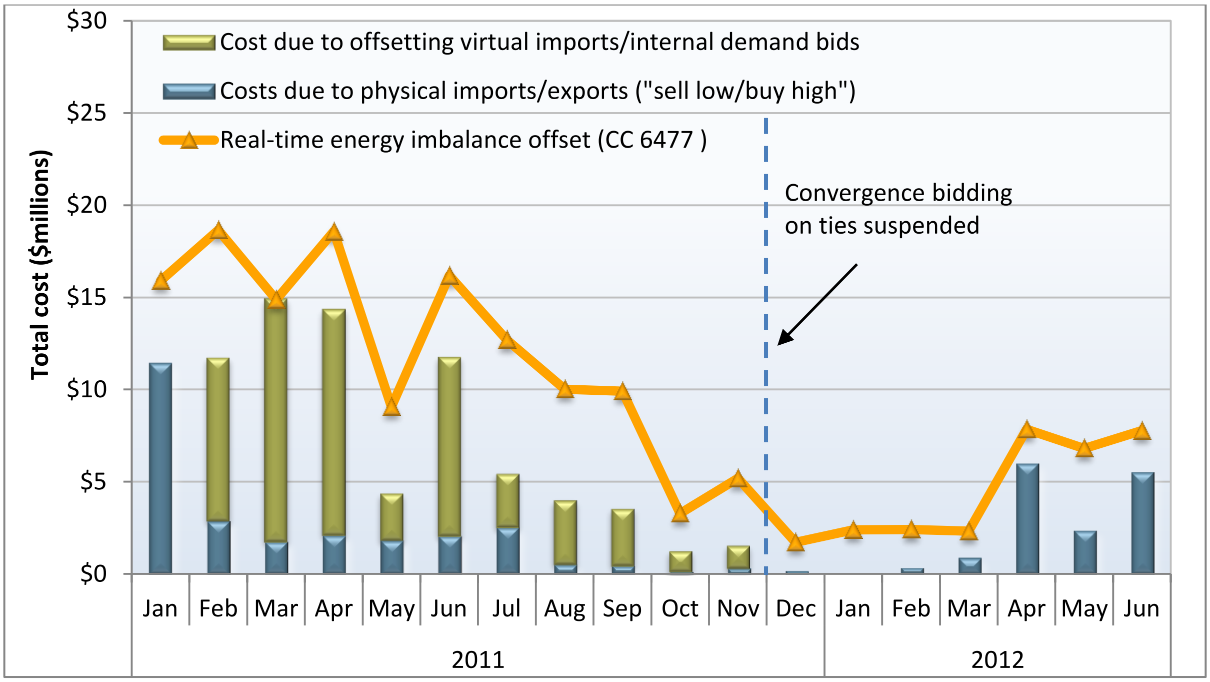
- Average real-time prices exceeded day-ahead and hour-ahead prices during the quarter, reversing a trend of improved price convergence that occurred in recent quarters (see Figure E.1). This price divergence was driven largely by an increase in the frequency of real-time price spikes. Many of these price spikes continue to be caused by brief limitations in upward ramping capacity. In the second quarter, congestion within the ISO system also caused additional price spikes in the real-time market.

Figure E.1 Average monthly system marginal energy prices (all hours)



- Real-time energy imbalance offset costs totaled $22 million in the second quarter (See Figure E.2). This is the highest quarterly value since the third quarter of 2011 when convergence bidding at the inter-ties was still allowed and contributed to these imbalance costs.[1] DMM estimates that about $14 million of these costs were driven by price divergence between the hour-ahead and real-time markets. In the hour-ahead market, exports were increased and imports were reduced at relatively low prices, while additional energy was dispatched at higher costs in the 5-minute real-time market.

Figure E.2 Estimated energy imbalance costs attributable to decreased net hour-ahead imports requiring dispatch of additional energy in 5-minute market at a higher price



- Congestion within the ISO system had an increased effect on overall prices in the second quarter in both the day-ahead and real-time markets. The impact of day-ahead and real-time congestion was relatively high in the SCE area, representing roughly 5 percent of the total prices in both markets. SDG&E congestion costs were about 5 percent of total costs in the day-ahead market and about 2 percent in the real-time market. While import limitations into San Diego increased congestion costs into the SDG&E area, import limitations into the SCE area lowered the congestion costs into the SDG&E area, most notably in the real-time market. Congestion primarily occurred as a result of the market addressing reliability concerns related to the outages of San Onofre Nuclear Generating Station (SONGS) units 2 and 3.

[1] When convergence bidding was allowed at inter-ties, real-time imbalance offset costs increased due to virtual import bids that offset virtual demand bids within the ISO system that did not increase the efficiency of unit commitment decisions. For further details see the *2011 Annual Report on Market Issues and Performance*, Chapter 4, http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was suspended on November 28, 2011.[2] Thus, the second quarter of 2012 represents the second full quarter with virtual bidding within the ISO system but not at the inter-ties. Convergence bids within the ISO system that are profitable may increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling. Convergence bidding within the ISO also provides a mechanism for participants to hedge against price differences due to congestion at different locations and between price differences between the day-ahead and real-time markets.

Convergence bidding activity was marked by several key trends in the second quarter:

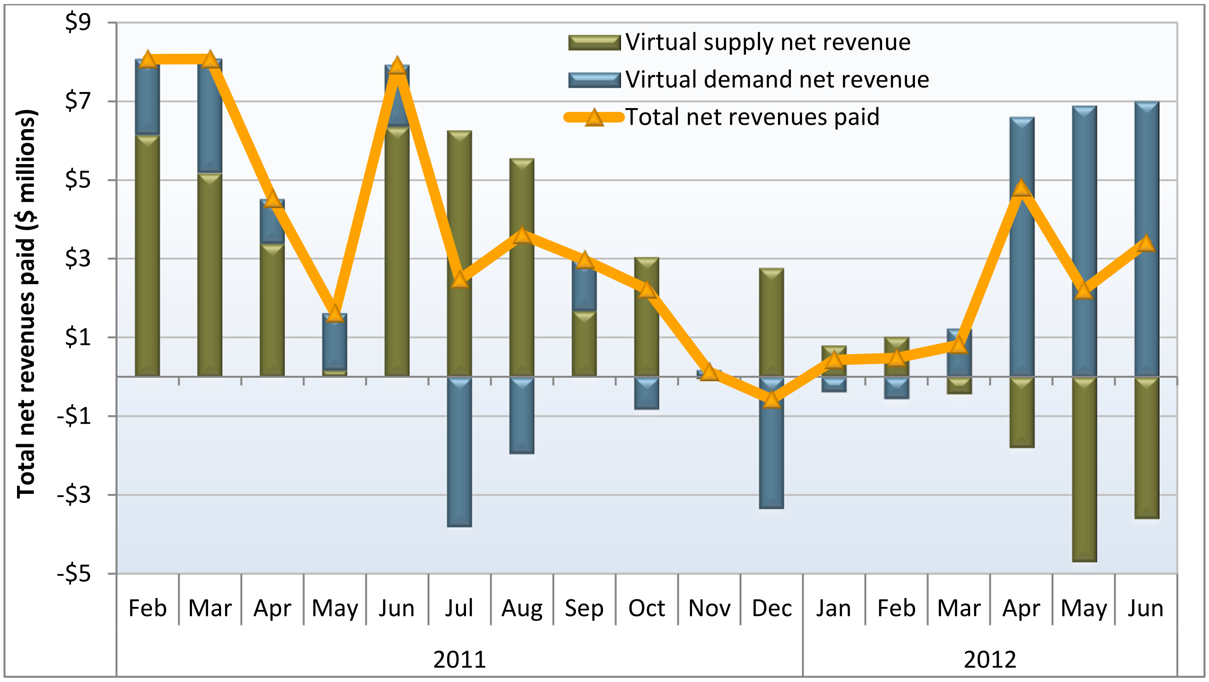
- Virtual demand at internal scheduling points within the ISO system exceeded virtual supply by an average of about 430 MW in the second quarter. For the quarter, internal virtual supply averaged around 1,040 MW while virtual demand averaged around 1,470 MW each hour. This trend of net virtual demand represents a reversal of a trend of net virtual supply that began in mid-December and continued through the first quarter.

- Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing an equal amount of virtual demand and supply bids at different internal locations during the same hour. This type of offsetting virtual position at internal locations accounted for an average of about 650 MW of demand offset by 650 MW of virtual supply at other locations per hour in the second quarter. These offsetting bids represent about 70 percent of all cleared internal virtual bids. This suggests that since suspension of virtual bidding on inter-ties virtual bidding has been heavily used to hedge or profit from internal congestion.

- In the second quarter, net revenues paid out to participants placing virtual bids totaled over $10 million (see Figure E.3). This is significantly above the level paid to convergence bidding entities in the first quarter ($2 million) and the highest quarterly level since the second quarter of 2011. The higher net revenues paid out for convergence bids reflect increasing price divergence because of the higher incidence of real-time price spikes and congestion. The net revenues primarily resulted from virtual demand positions. These virtual demand positions have the potential to increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling.

[2] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

Figure E.3 Total monthly net revenues paid to convergence bidders



Convergence bidding on inter-ties

DMM has recommended that the ISO not re-implement convergence bidding on inter-ties.[3] DMM's analysis of convergence bidding at inter-ties and review of alternatives shows that the potential costs of re-introducing convergence bidding at inter-ties outweigh the potential benefits. Recent market performance reinforces DMM's position. Specifically, the recent increase in price divergence and real-time imbalance offset costs would likely have been exacerbated had convergence bidding been allowed at the inter-ties. Thus, DMM believes that continued suspension of convergence bidding at the inter-ties remains important until the ISO addresses structural differences between how the hour-ahead and real-time markets are dispatched and settled.

Special issues

- **Flexible ramping constraint performance.** The flexible ramping constraint, implemented in December 2011, addresses non-contingency based deviations in load and supply between the real-time commitment and dispatch models (e.g., because of load and wind forecast variations). The constraint procures ramping capacity in the 15-minute real-time pre-dispatch process that is subsequently made available for use in the 5-minute real-time dispatch. The flexible ramping constraint was less effective in addressing real-time price volatility in the second quarter than in the first quarter. This may partly be a result of internal congestion in the real-time market. The flexible ramping constraint procures on a system-wide basis and was not designed to address zonal or local

[3] See DMM's *Comments on ISO's Third Revised Straw Proposal for Settlement of Interties in Real-time*, July 26, 2012: http://www.caiso.com/Documents/DMM-Comments-IntertiePricingSettlementThirdRevisedStrawProposal.pdf.

ramping issues. Furthermore, a lower requirement for the flexible ramping constraint was used than in the first quarter that may also have reduced its effectiveness. Total payments made for flexible ramping capacity during the first half of the year were around $14.8 million. For sake of comparison, payments for spinning reserve totaled about $12 million for the same period. DMM has recommended that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in real-time. DMM believes this is an important measure of the overall effectiveness of the constraint. Furthermore, DMM recommends that the ISO continue to fine tune the flexible ramping constraint to increase its effectiveness. Finally, given the high level of price divergence in recent months, DMM recommends that the ISO seek to identify and pursue other steps that might be taken to reduce extreme real-time price spikes and price divergence.

- **Performance of new local market power mitigation procedures.** The ISO implemented new local market power mitigation procedures in mid-April to enhance the competitive path assessment mechanism and mitigation trigger in the day-ahead market. In addition, the ISO incorporated virtual bids into the day-ahead mitigation run and began clearing that market run against bid-in demand instead of forecast load. These enhancements have improved the accuracy of local market power mitigation considerably by better aligning the model inputs between the mitigation and actual market runs. The dynamic competitive path assessment has also improved the accuracy of identifying where local market power exists by assessing competitiveness based on actual system and market conditions observed by the market software. Finally, the new mitigation trigger has improved the accuracy of local market power mitigation by applying bid mitigation only to resources where the locational margin8al price is increased by congestion on an uncompetitive constraint.

- **Compensating injections.** As DMM had highlighted in its 2011 annual report, the effectiveness of compensating injections, which are designed to help the real-time software better match actual and modeled flows on inter-ties, is significantly affected by limiting parameters.[4] These parameters not only limit the effectiveness of the compensating injections, they also add variability into the real-time model that can create operational challenges. This trend continued into the second quarter and created noticeable effects on certain constraints. As a result, the ISO has begun to regularly track the effectiveness of compensating injections and intends to reduce the variability by adjusting the limiting parameters.

[4] See DMM's *2011 Annual Report on Market Issues and Performance*, April 2012, Section 8.4, http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

1 Energy market performance

The day-ahead integrated forward market was stable and competitive. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions. Although real-time prices exceeded day-ahead prices in the second quarter, the real-time market continues to account for a very small portion of the wholesale market, so that overall market wholesale costs continue to highly competitive.

1.1 Energy market performance

Average real-time prices exceeded day-ahead and hour-ahead prices during the quarter, reversing a trend of improved price convergence that occurred in recent quarters. Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively.[5]

- In peak and off-peak periods in the second quarter, hour-ahead prices remained lower than day-ahead prices. With the exception of peak hours in July and off-peak hours in September, this pattern has held for over the last year.
- Prices in the 5-minute real-time market were higher than day-ahead prices in all months for peak hours and in May and June for off-peak periods in the second quarter.
- Prices in the 5-minute real-time market also exceeded hour-ahead prices in both peak and off-peak hours in all months during the second quarter. The largest average difference was over $13/MWh in June off-peak hours and about $11/MWh in April for peak hours.

Figure 1.1 and Figure 1.2 show that average hour-ahead and real-time market prices diverged during the second quarter relative to previous periods. Figure 1.3 and Figure 1.4 further highlight the systematic differences between hour-ahead and real-time prices in the second quarter.

- Figure 1.3 shows average hourly prices for the second quarter. In previous quarters, real-time prices were higher relative to day-ahead and hour-ahead prices in some hours and lower in other hours. In the second quarter, average real-time prices were above day-ahead and hour-ahead prices in all hours. Meanwhile, hour-ahead prices were consistently lower than both day-ahead and real-time prices for most of the day. This trend was also different from previous periods, when hour-ahead prices were higher than day-ahead and real-time prices in some hours and lower in others.
- Figure 1.4 highlights the magnitude of price differences in the hour-ahead and real-time markets based on this simple average of price differences in these markets, price divergence began in April and increased through June to an average of about $10/MWh for all hours of the month (see green line in Figure 1.4). This was the largest average price divergence since January 2011 and further emphasizes the trend in Figure 1.3 showing that real-time prices were consistently above hour-ahead prices in most hours.

[5] In previous reports, DMM has used the PG&E area price to illustrate price levels and price convergence. When congestion levels were low, the PG&E area price was a good approximation of the system price. However, congestion has begun to play an increasing role in recent quarters. As a result, DMM has switched its price analysis to the system marginal energy price, which is not affected by congestion or losses.

Figure 1.1 Average monthly on-peak prices – system marginal energy price

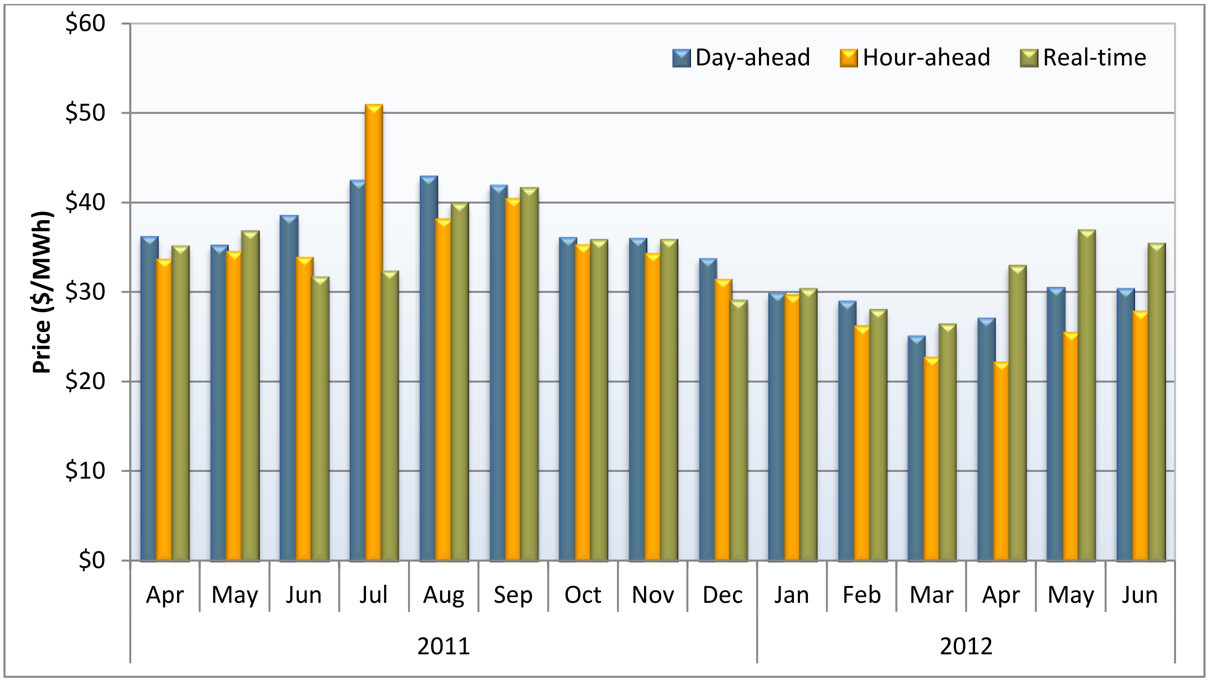


Figure 1.2 Average monthly off-peak – system marginal energy price

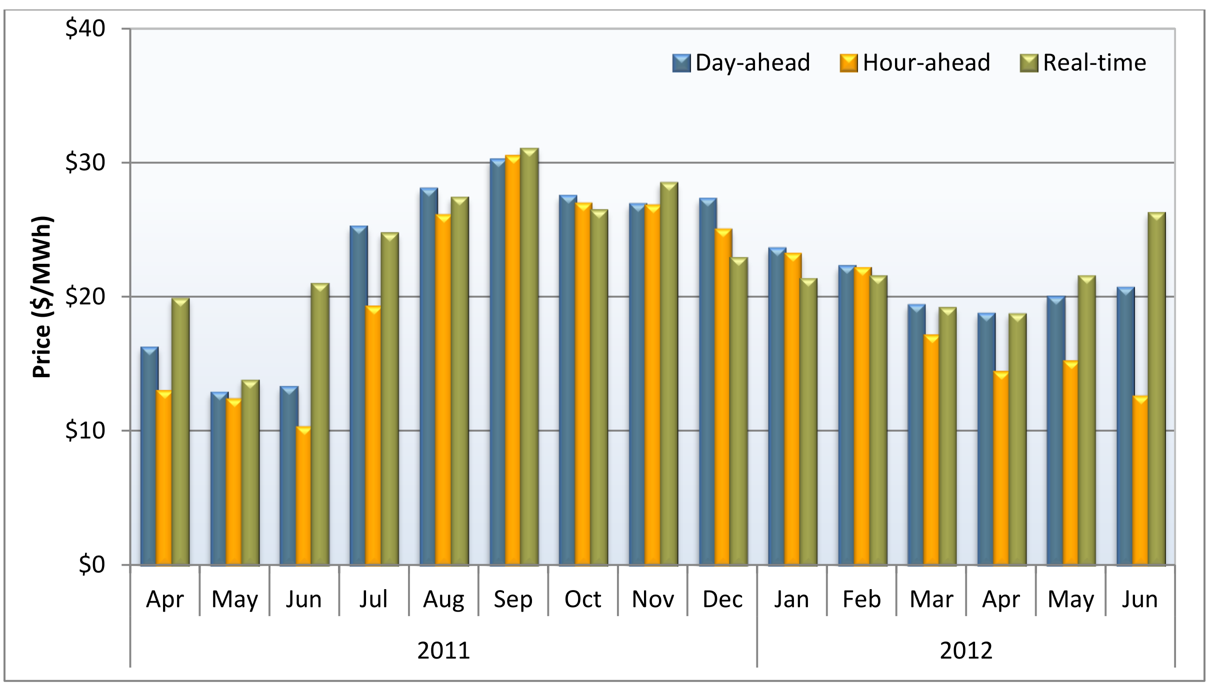


Figure 1.3 Hourly comparison of system marginal energy prices (April - June)

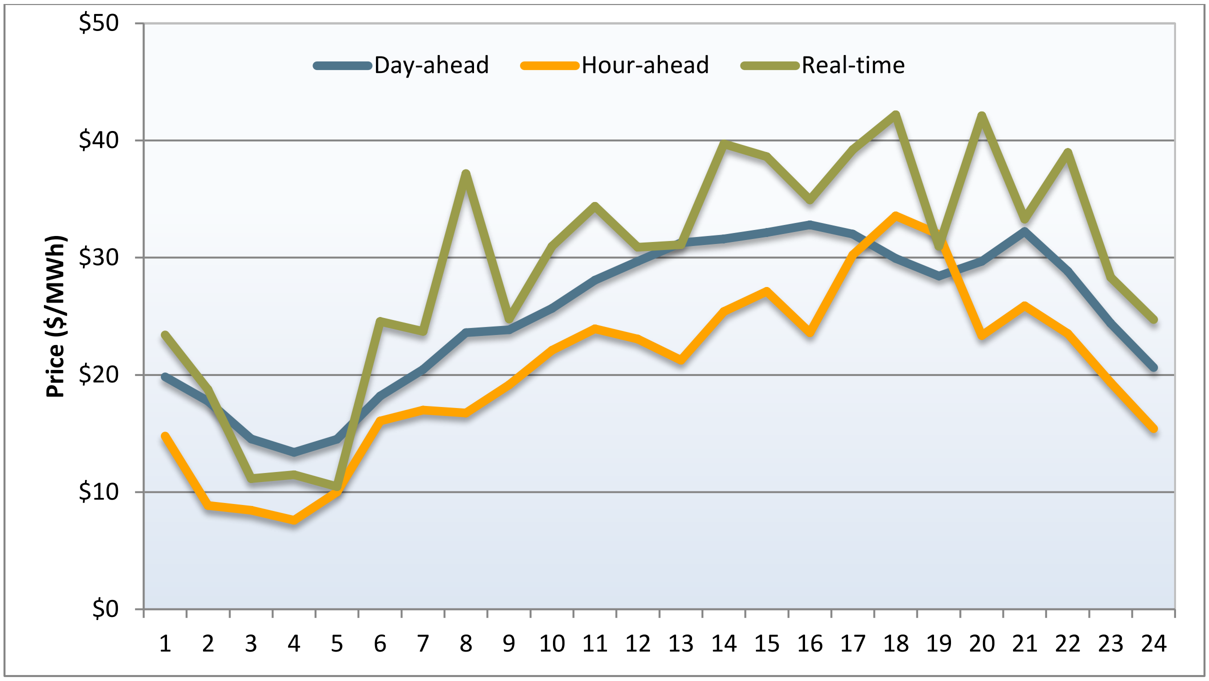
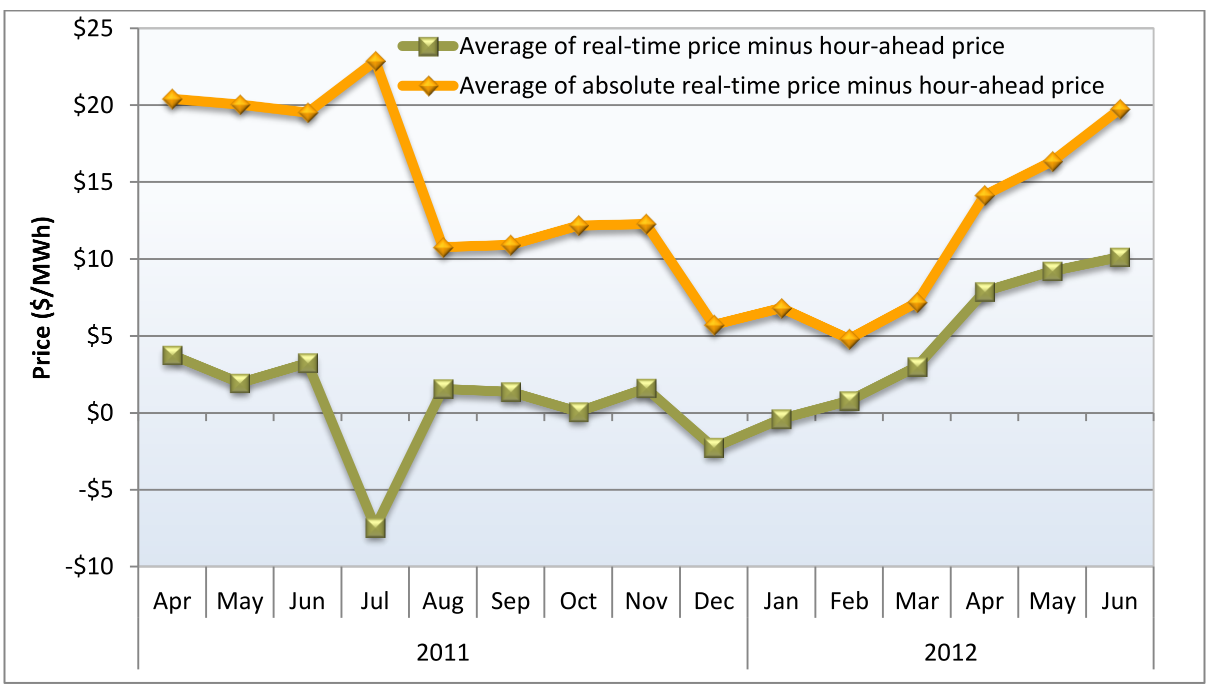


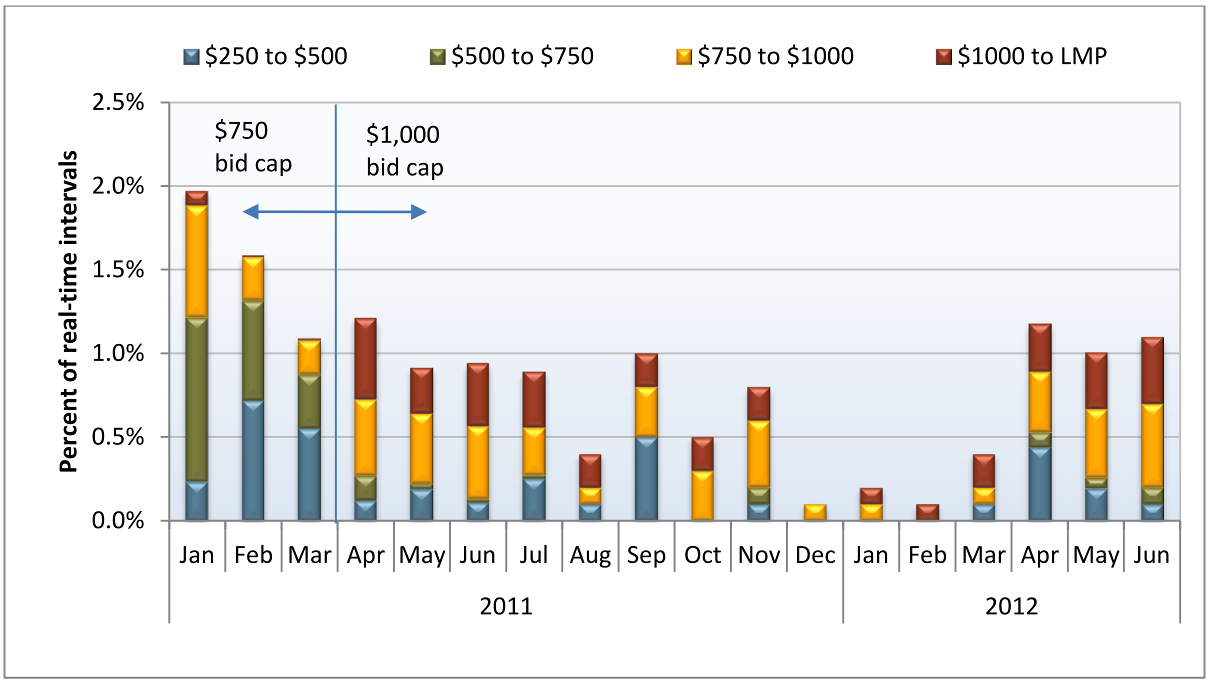
Figure 1.4 Difference in monthly hour-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)



- Also shown in Figure 1.4, the average absolute price difference in the hour-ahead and real-time markets shows that price divergence increased during the second quarter to almost $20/MWh in June (yellow line in Figure 1.4). This difference was about as large as the difference in average absolute prices during the second quarter of 2011.[6]

Figure 1.5 shows an increase in the frequency of price spikes that occur in each investor-owned utility area in the real-time market in the second quarter, from an average of 0.2 percent in the first quarter to about 1.1 percent in the second quarter. The second quarter had the highest percentage occurrence of price spikes since the first quarter of 2011. While the price spikes at or above $1,000/MWh in the second quarter of 2012 (0.3 percent) were slightly lower than in the second quarter of 2011 (0.4 percent), price spikes below $1,000/MWh increased in the second quarter of 2012 as a result of congestion related price spikes.

Figure 1.5 Frequency of price spikes (all LAP areas)



1.2 Power balance constraint

The system-wide real-time power balance constraint continues to contribute to extreme positive and negative real-time prices. Overall, power balance constraint relaxations show an increasing trend compared to previous quarters. Figure 1.6 and Figure 1.7 show the frequency the power balance constraint was relaxed in the 5-minute real-time market software since the second quarter of 2011.

[6] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. Mathematically, this measure will always exceed the simple average of price differences shown in Figure 1.4 if both negative as well as positive price differences occur. If the magnitude decreases, price convergence would be improving. If the magnitude increases, price convergence would be getting worse. DMM does not anticipate that the average absolute price convergence should be zero. This metric is considered secondary to the simple average metrics and helps to further interpret price convergence.

Figure 1.6 Relaxation of power balance constraint because of insufficient upward ramping capacity

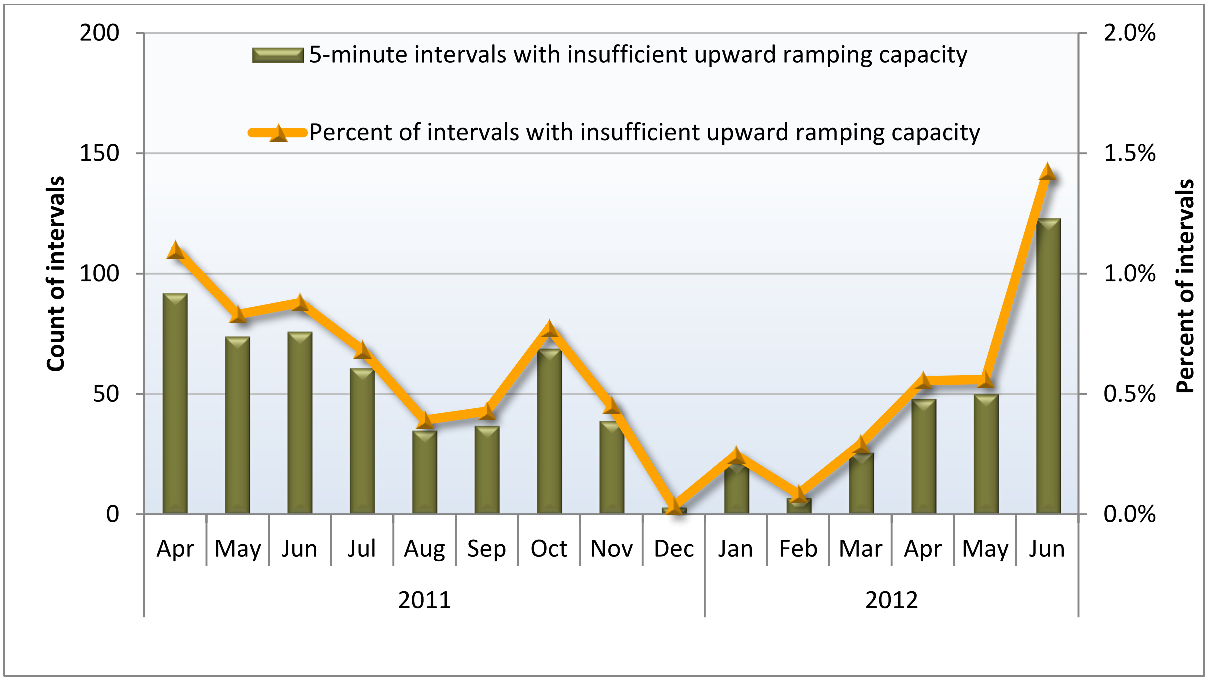
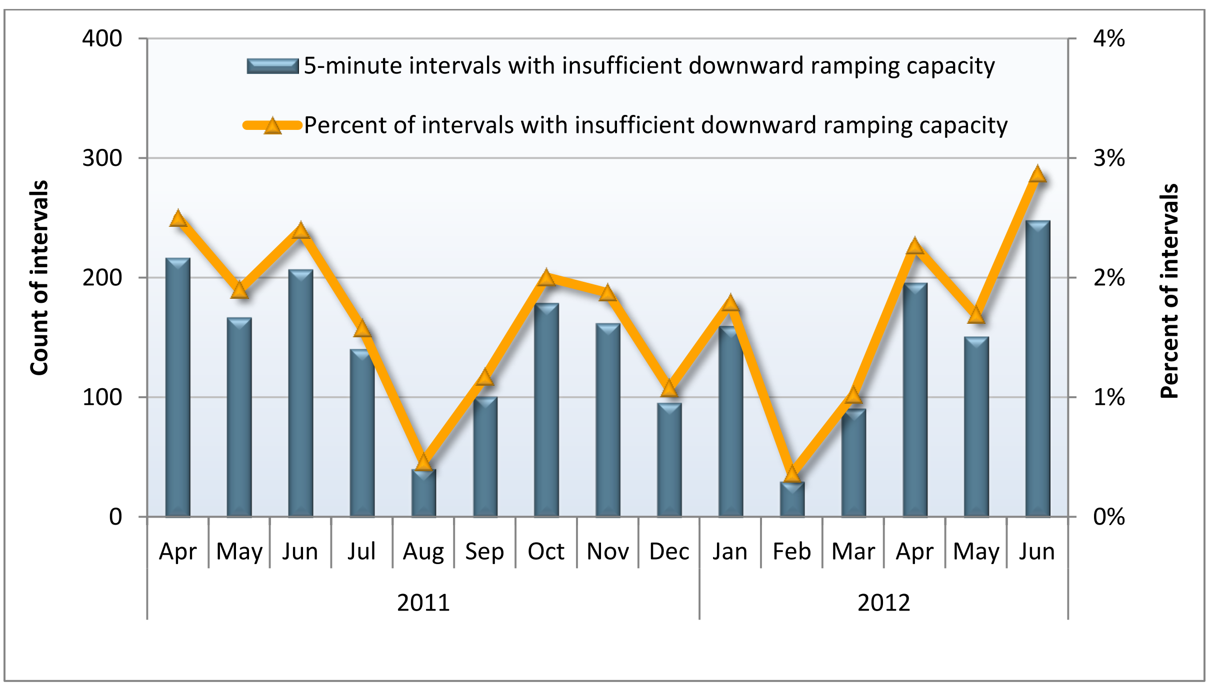


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity



- Figure 1.6 shows that relaxations because of insufficient upward ramping capacity began an upward trend in the second quarter, peaking in June. The constraint relaxations were dispersed over different hours of the day but were slightly more common between 3:00 p.m. and 8:00 p.m., during the evening load ramp and peak. Decreased capacity availability from planned generator outages, the continued outage of SONGS nuclear units, limited ramping capacity, increased load because of hot weather in June and congestion all appear to have contributed to increasing the number of upward ramping limitations. When these upward ramping limitations occur, the real-time system energy price is set by a penalty parameter equal to the bid cap of $1,000/MWh.

- Figure 1.7 shows an increase in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the second quarter relative to the first quarter. Almost 80 percent of downward ramping limitations occurred in hours ending 1 through 8. In these hours, power balance constraint relaxations occurred in around 4 percent of the intervals. In hour ending 7, one of the key ramping hours, almost 8 percent of the intervals had a downward power balance constraint relaxation. One of the causes of these decremental dispatch insufficiencies includes unanticipated changes in variable unit output in the early morning hours. The flexible ramping constraint cannot resolve relaxations from insufficiencies of dispatchable decremental energy as it has only been applied to address upward, not downward, ramping limitations. When these downward ramping limitations occur, the real-time system energy price is set by a penalty parameter equal to the bid floor of -$30/MWh.

Most shortages of upward and downward ramp limitations lasted for only short periods of time. For instance, about 83 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). Even so, these upward ramping shortages can cause real-time prices to increase dramatically and greatly outweigh the effects of the negative prices associated with the more frequent downward ramping shortages. Figure 1.8 and Figure 1.9 control for the effects of these ramping limitations by removing the prices in all markets in hours with real-time ramping limitations and highlight the change in prices when these hours are removed.

- Figure 1.8 highlights the degree to which monthly average price differences were caused by extreme prices during the small percentage of intervals when power balance constraint relaxations occurred. The main bars represent the price results in the day-ahead, hour-ahead and real-time markets after the adjustments were made. The smaller bars (designated as Diff), indicate how the price differs between the original prices and the adjusted prices. As Figure 1.8 shows, when these intervals were excluded, real-time prices were very close to day-ahead prices in April and May, and were slightly lower than day-ahead prices in June.

- Figure 1.9 highlights the difference between average hour-ahead and real-time prices when comparing hours where power balance constraint relaxations are excluded with prices that include them. As seen in this figure, average real-time prices in the second quarter remained higher than average hour-ahead prices even when the ramping limitations were accounted for. This was the result of multiple factors including modeling differences between the hour-ahead and real-time markets as well as differences in load and generation.

Figure 1.8 Change in monthly prices excluding hours when power balance constraint relaxed

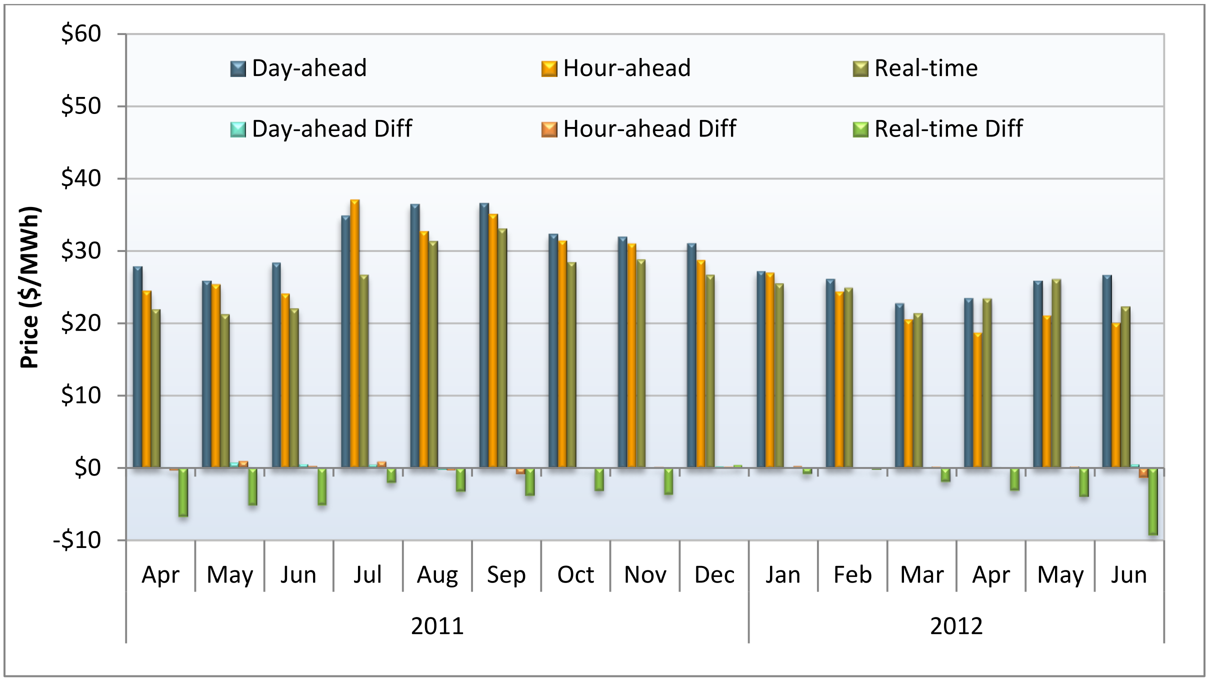
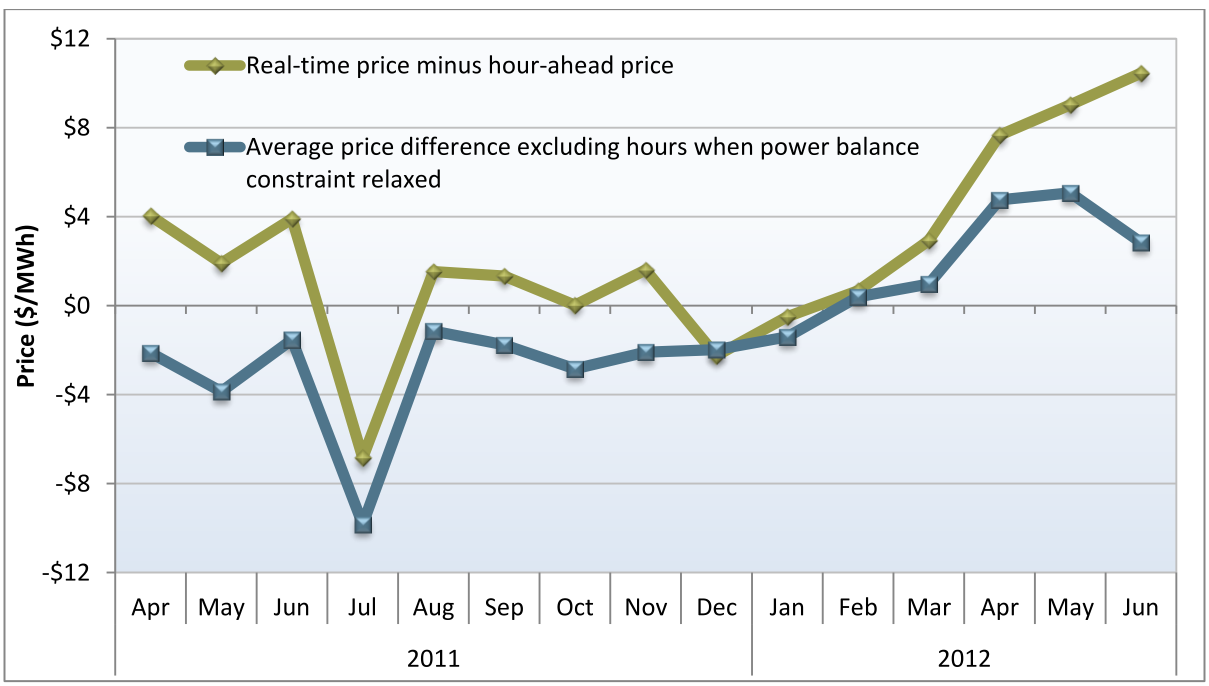


Figure 1.9 Difference in monthly hour-ahead and real-time prices excluding hours when power balance constraint relaxed

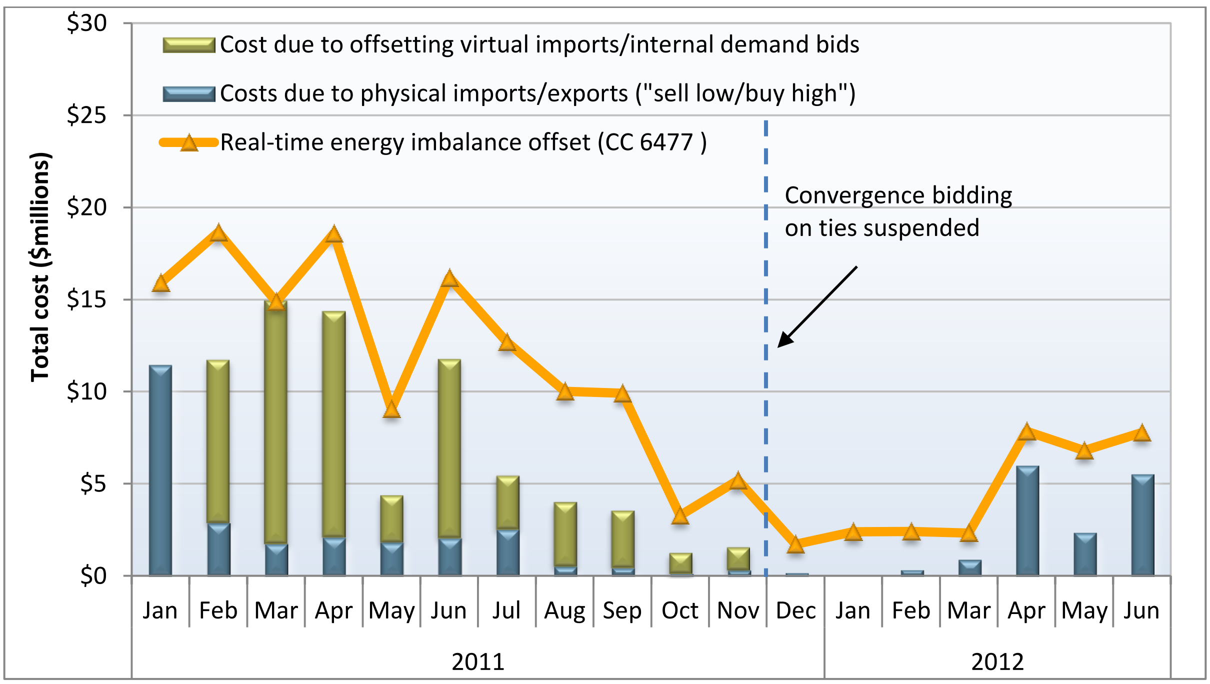


1.3 Real-time imbalance offset costs

Real-time energy imbalance offset costs totaled $22 million in the second quarter. This increase was primarily driven by price divergence between the hour-ahead and real-time markets. In the hour-ahead market, exports were increased and imports were reduced at relatively low prices, while additional energy was dispatched at higher costs in the 5-minute real-time market. These conditions were very similar to conditions that occurred in the market in 2009 and 2010.[7]

Figure 1.10 compares the total real-time energy imbalance costs (yellow line) with the portion of these costs DMM estimates are attributable to (1) additional imbalance energy because of changes in net imports in the hour-ahead that are offset by imbalance energy in real-time at a different price (blue bar)[8] and (2) offsetting convergence bids at inter-ties and internal locations (green bar). The estimated imbalance costs due to physical schedules during the second quarter of 2012 increased to about $14 million from about $6 million during the second quarter of 2011.

Figure 1.10 Estimated energy imbalance costs because of decreased net hour-ahead imports requiring dispatch of additional energy in 5-minute market at a higher price



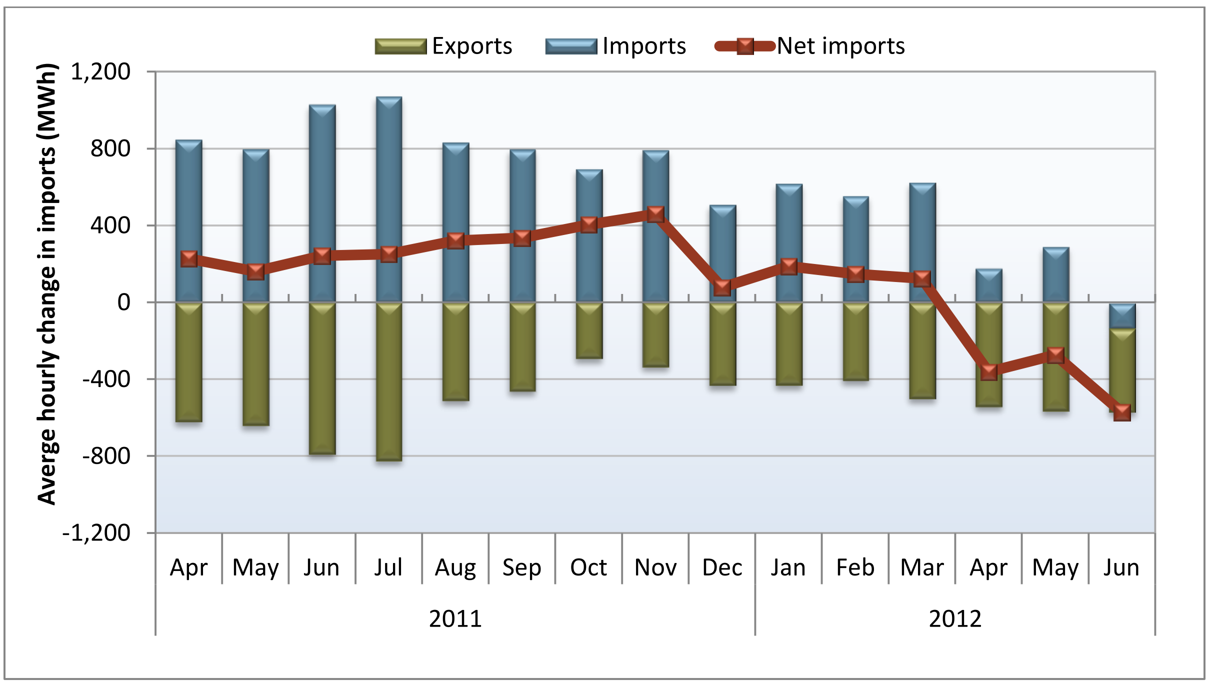
[7] See DMM's *2009 Annual Report on Market Issues and Performance,* p. 7, http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf and *2010 Annual Report on Market Issues and Performance*, p. 5, http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[8] DMM estimates these costs based on the following: 1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time from dispatchable generation; 2) the increase in hour-ahead imports that were subsequently sold in real-time; and 3) the difference in hour-ahead versus real-time prices during the corresponding hour. This cost estimate is only one element of the real-time imbalance energy offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

The increase in estimated physical net import costs was a result of increased price divergence between the hour-head and real-time market prices along with decreases in net imports in the hour-ahead market.[9] From the second quarter of 2011 through the first quarter of 2012, the net import schedules clearing the hour-ahead market were systematically higher than the net import schedules clearing the day-ahead market. This pattern shifted in the second quarter of 2012. As shown in Figure 1.11:

- During each month from the second quarter of 2011 through the first quarter of 2012, net imports clearing the hour-ahead market averaged 500 MW to 1,000 MW more than net day-ahead import schedules. Most of the increase in net imports was because of an increase in new imports in the hour-ahead market, which averaged over 400 MW per hour from the second quarter of 2011 through the first quarter of 2012.
- The trend of positive net imports flipped during the second quarter of 2012 when new exports in the hour-ahead market outweighed new imports by an average of 400 MW during the quarter.

Figure 1.11 Change in net imports in hour-ahead relative to the final day-ahead schedules



Decreasing physical net imports in the hour-ahead market likely increases the need to re-dispatch imbalance energy in real-time.[10] This scenario occurred in almost 90 percent of the hours in the second

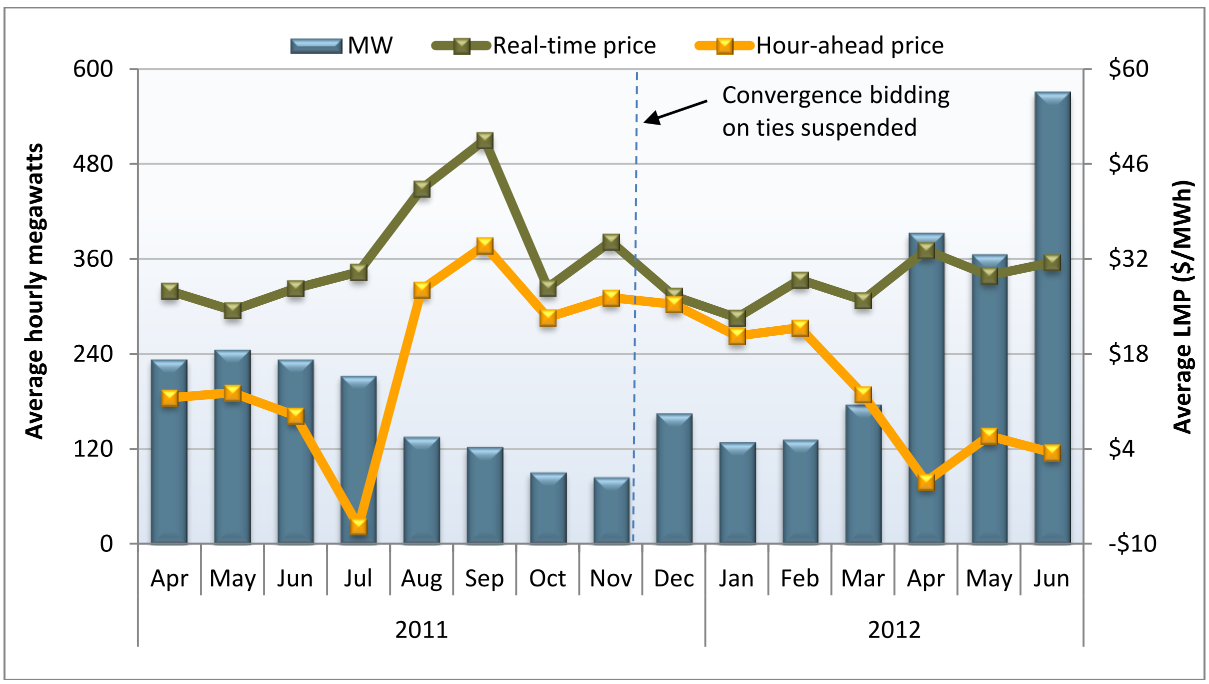
[9] The hour-ahead market allows day-ahead inter-tie schedules to be modified through a re-optimization of the entire market. Market participants with accepted day-ahead imports or export bids can either self-schedule their energy in the hour-ahead market, or re-bid day-ahead scheduled quantities at the same or different prices. If an import scheduled in the day-ahead market does not clear in the hour-ahead market, the market participant buys back the import at the hour-ahead price. Exports scheduled in the day-ahead market that do not clear in the hour-ahead market are sold back at the hour-ahead price.

[10] In some cases, reductions in net imports may occur in the hour-ahead market to manage congestion or reduce supply because of energy not scheduled in the day-ahead market, such as renewable generation or unscheduled start-up or minimum load energy from thermal units. The hour-ahead software takes this energy into account while optimizing imports and exports.

quarter. The blue bars in Figure 1.12 show DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month. The lines in Figure 1.12 compare the corresponding weighted average prices at which this decrease in net imports was settled in the hour-ahead market and the weighted average prices for additional energy procured in the real-time market during each month.[11] Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are determined by the quantity that is reduced in the hour-ahead market and then re-procured in the 5-minute real-time market, combined with the difference in prices in these two markets.

As shown in Figure 1.12, there has been a substantial increase in the price divergence between hour-ahead and 5-minute real-time market prices in the second quarter of 2012 compared to the second quarter of 2011 as well as an increase in quantity of megawatts bought back. The average price difference in the second quarter of 2012 was around $29/MWh with an increased average quantity of about 445 MW compared to a price difference of about $16/MWh and a quantity of 240 MW in the second quarter of 2011.

Figure 1.12 Monthly average quantity and prices of net import reductions in hour-ahead market and resulting increase in real-time energy dispatched



[11] DMM estimates the hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month based on the difference between the decrease in net imports each hour with the amount of energy dispatched in the 5-minute market during that hour. For instance, if the net imports were decreased by 500 MW in the hour-ahead, and 700 MW of net incremental energy was dispatched in the 5-minute market that hour, the entire 500 MW decrease of net imports in hour-ahead was re-procured in the 5-minute market. If net imports were decreased by 500 MW in the hour-ahead market, but only 200 MW of net incremental energy was dispatched in the 5-minute market that hour, then only 200 MW of the decrease of net imports in hour-ahead was counted as being re-procured in the 5-minute market.

1.4 Congestion

Compared to the first quarter, congestion within the ISO system in the second quarter had an increased effect on overall prices in the day-ahead and real-time markets. Much of the congestion was related to the outages of the San Onofre Nuclear Generating Station units 2 and 3, in conjunction with other generation and transmission outages.

The impact of congestion on any constraint on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.

Often, congestion on constraints within Southern California increases prices within the Southern California Edison and San Diego Gas and Electric areas, but decreases prices in the Pacific Gas and Electric area. This is the inverse of congestion in Northern California. The price impacts on individual constraints can differ between the day-ahead and real-time markets as seen in the following sections.

1.4.1 Congestion impacts of individual constraints

Day-ahead congestion

Congestion in the day-ahead market generally occurs more frequently than in real-time, but with smaller price impacts. Table 1.1 provides a more detailed analysis for the second quarter and shows:

- At almost 36 percent of the hours, the SCE_PCT_IMP_BG was congested more often than any other individual constraint in the quarter. This constraint alone increased the prices in the SCE area by $3.40/MWh in congested hours. The prices in the PG&E and SDG&E areas decreased by $2.87/MWh. This constraint has been directly affected by the outages of SONGS units 2 and 3.

- The SLIC 18830001_SDGE_OC_NG constraint had the second highest percent of hours binding during the second quarter at just under 32 percent. This constraint increased the prices in the SDG&E area by $6.46/MWh in congested hours and SCE by $0.28/MWh while decreasing prices on PG&E by $0.71/MWh. This constraint is directly related to the outage of SONGS and ended with the addition of the Sunrise Power Link in mid-June.

- Congestion on the 6110_TM_BNK_TMS_DLO_NG increased prices in the PG&E area by $0.80/MWh in congested hours and decreased prices in the SCE and SDG&E areas by about $0.85/MWh. This congestion was related to scheduled maintenance.

As shown in Table 1.1, congestion on other constraints significantly affected prices during hours when congestion occurred. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices.

Table 1.1 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency		Q1			Q2		
Area	Constraint	Q1	Q2	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	6110_TM_BNK_FLO_TMS_DLO_NG		6.3%				$0.80	-$0.85	-$0.85
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	8.6%		$1.24	-$0.97	-$0.97			
SCE	SCE_PCT_IMP_BG	4.6%	35.6%	-$1.31	$1.62	-$1.31	-$2.87	$3.40	-$2.87
	PATH26_BG	4.8%	3.6%	-$1.63	$1.39	$1.39	-$1.41	$1.16	$1.16
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2		0.7%				-$3.22	$2.39	$2.44
	SLIC1852244PATH26LIOSN2S	4.7%		-$1.98	$1.66	$1.66			
	SLIC1883001 MIGUEL BKS	1.4%		-$0.14		$5.01			
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.0%		-$1.15	$1.65	-$1.93			
	SLIC 1848345_23021_Outage	0.5%		-$1.17		$7.79			
SDG&E	SLIC 1883001_SDGE_OC_NG	14.2%	31.7%	-$0.65	-$0.06	$6.27	-$0.71	$0.28	$6.46
	SDGE_CFEIMP_BG	9.0%	2.4%	-$0.45	-$0.45	$4.19	-$0.56	-$0.56	$5.64
	SDGE_PCT_UF_IMP_BG		1.1%				-$0.40	-$0.40	$4.27
	SLIC 1883001 Miguel_BKS_NG_2	2.4%	0.9%	-$0.07		$3.08	-$0.45		$6.79
	SLIC 1977036 Barre-Ellis NG		0.5%				-$0.75		$6.90
	22832_SYCAMORE_230_22828_SYCAMORE_69.0_XF_2	0.1%				$24.09			

Real-time congestion

Congestion in the real-time market differs slightly from the day-ahead market in that real-time congestion occurs less frequently overall, but often on more constraints and with a larger price effect in the intervals when it occurs. Table 1.2 provides a detailed analysis for the second quarter and shows:

- Congestion on SLIC 1902749 ELDORADO_LUGO-1 occurred nearly 2 percent of the time. At those times, congestion increased prices in the PG&E area by $12.43/MWh and decreased prices in the SCE and SDG&E areas by $8.32/MWh and $14.48/MWh, respectively. This congestion was due to scheduled maintenance.

- SCE_PCT_IMP_BG was congested slightly more than 2 percent of the hours and was congested as a result of the outages of SONGS units 2 and 3. This congestion decreased the prices in the PG&E and SDG&E areas by about $70/MWh and increased prices for the SCE area by over $86/MWh during congested hours. Path26_N-S and Path15_N-S were also congested about 2 percent of the time, increasing prices in SCE and SDG&E by nearly $49/MWh and $29/MWh, respectively. Prices decreased in PG&E by nearly $60/MWh and $38/MWh, respectively.

- In nearly 3 percent of the hours, congestion on SLIC 1883001_SDGE_OC_NG increased the price in the SDG&E area about $69/MWh when it was binding. PG&E prices decreased by about $8/MWh while the impact on the SCE area price was negligible. This constraint is directly related to the outage of SONGS.

Comparing Table 1.1 and Table 1.2 indicates that congestion is more frequent in the day-ahead market compared to the real-time market. However, the price impact of congestion is lower in the day-ahead market than the real-time market. Differences in congestion in the day-ahead and real-time markets occur as system conditions change, as convergence bids liquidate, and as constraints are sometimes adjusted in real-time to make market flows consistent with actual flows and to provide reliability margin.

For example, while the SCE_PCT_IMP_BG was binding in nearly 36 percent of the hours in the day-ahead market, it was binding in about 2 percent of the time in the real-time market. The constraint increased day-ahead prices in the SCE area by $3.40/MWh, but by over $86/MWh in the real-time market. Other examples include nomograms, such as PATH26_N-S and PATH15_S-N, which may be adjusted to mitigate the difference in market and actual flows and to provide a reliability margin. Even though the nomograms are binding less frequently (in about 2 percent of the hours for each constraint), the shadow prices are significantly larger, indicating a greater impact on prices when the constraint is binding.

Table 1.2 Impact of congestion on real-time prices by load aggregation point in congested intervals

		Frequency		Q1			Q2		
Area	Constraint	Q1	Q2	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	SLIC 1902749 ELDORADO_LUGO-1	1.1%	1.7%	$3.30	-$2.36	-$3.96	$12.43	-$8.32	-$14.48
	6110_TM_BNK_FLO_TMS_DLO_NG		1.7%				$20.04	-$25.77	-$25.77
	LBN_S-N	0.02%	0.5%	$1.59	-$1.29	-$1.29	$228.26	-$199.05	-$199.05
	LOSBANOSNORTH_BG	0.01%	0.1%	$3.22	-$2.74	-$2.74	$179.78	-$142.40	-$142.40
	PATH15_S-N		0.1%				$59.14	-$50.27	-$50.27
	SLIC 1977990 SYL_PAR_NG		0.03%				$26.58	-$20.03	-$98.65
	PATH26_S-N	0.3%	0.02%	$30.46	-$25.84	-$25.84	$1.63	-$1.41	-$1.41
	SLIC 1902748 ELDORADO_LUGO-1	1.1%		$4.29	-$2.98	-$6.43			
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.2%		$4.76	-$3.65	-$3.65			
SCE	SCE_PCT_IMP_BG	0.2%	2.2%	-$63.37	$79.72	-$63.37	-$69.78	$86.32	-$69.66
	PATH26_N-S	2.8%	2.1%	-$17.37	$14.65	$14.65	-$59.99	$48.95	$48.95
	PATH15_N-S		1.7%				-$38.79	$29.03	$29.03
	SLIC-1832324-SOL7		0.7%				-$26.50	$17.82	$17.82
	SLIC 1832324_SOL7_REV1		0.4%				-$8.11	$5.52	$5.52
	7680 Sylmar_1_NG	0.1%	0.1%			-$60.31	-$11.98	$6.19	-$29.41
	PATH26_BG		0.1%				-$66.41	$50.25	$50.25
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.02%	0.1%	-$18.58	$22.52	-$70.75	-$10.86	$9.51	-$45.44
SDG&E	SLIC 1883001_SDGE_OC_NG	5.3%	2.7%	-$2.64	-$0.08	$24.17	-$8.17		$68.55
	7820_TL 230S_OVERLOAD_NG	0.2%	1.1%			$3.64			$50.51
	SLIC 1884984 Gould-Sylmar		0.5%						-$57.35
	230S overload for loss of PV		0.5%						-$51.27
	SDGEIMP_BG		0.1%				-$17.03	-$17.03	$172.81
	HASYAMPA-NGILA-NG1		0.1%				-$20.22		$141.43
	SDGE_CFEIMP_BG	0.7%	0.1%	-$3.91	-$3.91	$36.83	-$5.16	-$5.16	$54.25
	SOUTHLUGO_RV_BG	0.1%	0.05%	-$74.07	$59.77	$80.34	-$5.40	$3.82	$6.26
	SLIC 1883001 Miguel_BKS_NG_2	1.2%	0.02%			$14.54			$3.77
	SLIC1852244PATH26LIOSN2S	2.8%		-$7.22	$6.02	$6.02			
	SLIC1883001 MIGUEL BKS	1.4%				$20.10			
	SLIC 1883001 Miguel_BKS_NG	1.0%				$14.23			
	SOUTHEAST_IMPORTS	1.0%				$8.73			
	SLIC 1846936_23021_Outage	0.4%		-$1.78		$12.45			
	SLIC 1908221_22_23028-9_NG	0.2%				-$33.54			

1.4.2 Congestion impact on average prices

This section provides an assessment of differences on overall average prices in the day-ahead and real-time markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is made based on the average congestion component of the price as a percent of the total price during all congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact that congestion has when it occurs.[12]

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load aggregation area in the second quarter of 2012 by constraint. These results show the following:

- Limitations on imports increased day-ahead prices in the SCE area above system average prices by $1.21/MWh or around 4.7 percent. This constraint is designed to ensure that enough generation is being supplied from units within the SCE area in the event of a contingency that significantly limits imports into SCE or decreases generation within the SCE area.
- Day-ahead prices in the San Diego area were impacted the most by internal congestion associated with the outage of SONGS units 2 and 3. Congestion increased average day-ahead prices in the San Diego area above the system average by over $2/MWh or about 7.7 percent, mainly because of import limitations into the SDG&E area. Congestion costs were decreased into SDG&E, however, as a result of import limitations into the Southern California Edison system (SCE_PCT_IMP_BG). This congestion caused SDG&E area prices to fall by over $1/MWh, or just under 4 percent of the price.
- The overall impact of congestion on day-ahead prices in the PG&E area decreased prices by about $1.29/MWh or about 5.4 percent from the system average. This occurs because prices in the PG&E area are lower when congestion occurs on the constraints that limit flows in the north-to-south direction and on constraints limiting flows into the SCE and SDG&E areas.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$1.02	-4.19%	$1.21	4.67%	-$1.02	-3.81%
SLIC 1883001_SDGE_OC_NG	-$0.22	-0.92%		0.01%	$2.05	7.66%
SDGE_CFEIMP_BG	-$0.01	-0.05%	-$0.01	-0.05%	$0.13	0.50%
PATH26_BG	-$0.05	-0.21%	$0.04	0.16%	$0.04	0.16%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.05	0.21%	-$0.03	-0.10%	-$0.03	-0.10%
SLIC 1883001 Miguel_BKS_NG_2		-0.01%			$0.06	0.23%
SDGE_PCT_UF_IMP_BG		-0.02%		-0.02%	$0.05	0.18%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	-$0.02	-0.09%	$0.02	0.06%	$0.02	0.06%
SLIC 1977036 Barre-Ellis NG		-0.01%			$0.03	0.12%
SOUTHLUGO_RV_BG	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.03%
Other		-0.02%		-0.01%	$0.05	0.17%
Total	-$1.30	-5.4%	$1.23	4.8%	$1.39	5.2%

Real-time price impacts

Table 1.4 shows the overall impact of real-time congestion on average prices in each load area in the second quarter of 2012 by constraint. These results show the following:

[12] In addition, this approach identifies price differences caused by congestion without including price differences that result from variations in transmission losses at different locations.

- Congestion drove prices in the SCE area above system average prices by about $1.96/MWh or just over 6 percent. Most of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area (SCE_PCT_IMP_BG). Another major driver was congestion in the north-to-south direction on Path 26 and Path 15. SCE congestion fell by about $1/MWh (3 percent) when LBN_S-N was constrained.

- Prices in the San Diego area were impacted the most by internal congestion associated with the outage of SONGS, sometimes driving prices up and other times down. As with the day-ahead, congestion in the SCE area drove SDG&E prices down (e.g., SCE_PCT_IMP_BG) while SDG&E import constraints drove prices up (e.g., SLIC_1883001_SDGE_OC_NG). This situation caused average real-time prices in the San Diego area to increase only by about $0.53/MWh or about 2 percent above the system average.

- The overall impact of congestion on prices in the PG&E area was to change prices from the system average by about -$2.12/MWh or about -7.3 percent. This happens because prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction (e.g., Path 26) and on constraints limiting flows into the SCE and SDG&E areas. Congestion related to the Los Banos constraint increased prices over $1.12/MWh (almost 4 percent) during the second quarter.

Table 1.4 Impact of congestion on overall real-time prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$1.55	-5.38%	$1.92	6.20%	-$1.55	-5.21%
PATH26_N-S	-$1.24	-4.31%	$1.01	3.27%	$1.01	3.41%
LBN_S-N	$1.12	3.87%	-$0.97	-3.14%	-$0.97	-3.27%
SLIC 1883001_SDGE_OC_NG	-$0.22	-0.78%			$1.88	6.33%
PATH15_N-S	-$0.65	-2.25%	$0.49	1.57%	$0.49	1.64%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.33	1.15%	-$0.35	-1.12%	-$0.35	-1.17%
SLIC 1902749 ELDORADO_LUGO-1	$0.21	0.73%	-$0.14	-0.45%	-$0.25	-0.82%
7820_TL 230S_OVERLOAD_NG					$0.54	1.82%
LOSBANOSNORTH_BG	$0.18	0.62%	-$0.14	-0.46%	-$0.14	-0.48%
SLIC-1832324-SOL7	-$0.18	-0.64%	$0.12	0.40%	$0.12	0.42%
SLIC 1884984 Gould-Sylmar					-$0.30	-1.02%
230S overload for loss of PV					-$0.27	-0.91%
SDGEIMP_BG	-$0.02	-0.06%	-$0.02	-0.06%	$0.19	0.62%
HASYAMPA-NGILA-NG1	-$0.02	-0.08%			$0.16	0.54%
PATH26_BG	-$0.07	-0.23%	$0.05	0.16%	$0.05	0.17%
PATH15_S-N	$0.05	0.19%	-$0.05	-0.15%	-$0.05	-0.15%
SLIC 1832324_SOL7_REV1	-$0.04	-0.12%	$0.02	0.08%	$0.02	0.08%
24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	-$0.01	-0.03%	$0.01	0.03%	-$0.04	-0.15%
SDGE_CFEIMP_BG		-0.01%		-0.01%	$0.04	0.13%
7680 Sylmar_1_NG		-0.01%		0.01%	-$0.04	-0.13%
SLIC 1977990 SYL_PAR_NG	$0.01	0.02%	-$0.01	-0.01%	-$0.03	-0.10%
Other		-0.01%	$0.01	0.02%	$0.01	0.02%
Total	-$2.12	-7.3%	$1.96	6.3%	$0.53	1.8%

While real-time congestion occurred less frequently than day-ahead congestion, its overall price impact was larger than what occurred in the day-ahead market. As mentioned earlier, the differences in congestion can be attributed to differences in market conditions as well as changes associated with conforming line limits to make market flows reflect actual flows as well as to provide a reliability margin.

2 Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Virtual bidding is a part of FERC's standard market design and is in place at all other ISO's with day-ahead energy markets. Virtual bidding on inter-ties was suspended on November 28, 2011.[13] Thus, the second quarter of 2012 represents the second full quarter with virtual bidding within the ISO system but not at the inter-ties.

Convergence bids at points within the ISO that are profitable may increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling. Convergence bidding also provides a mechanism for participants to hedge against price differences due to congestion at different locations and between price differences between the day-ahead and real-time markets.

Participants in virtual bidding were paid net revenues of about $10 million in the second quarter. Most of these net revenues resulted from virtual demand bids at internal locations, reflecting the systematic trend of higher average real-time prices compared to day-ahead prices or the quarter. Internal virtual supply averaged around 1,040 MW while virtual demand averaged around 1,470 MW each hour during the quarter. The average hourly net virtual position in the second quarter was 430 MW of virtual demand. Net virtual demand within the ISO may help to increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling, and reducing real-time prices.

Background

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the hour-ahead and real-time markets, which are dispatched based on physical supply and demand only. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time markets as follows:

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. Virtual demand at points within the ISO is then paid the real-time price for these bids.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. Virtual supply at points within the ISO is then charged the real-time price.

Thus, virtual bidding allows participants to profit by arbitraging the difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to make prices in these different markets closer. For instance:

[13] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.

- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[14] This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

2.1 Convergence bidding trends

Total hourly trading volumes increased to 2,500 MW in the second quarter from 2,300 MW in the first quarter. Also, the net virtual positions shifted from primarily net virtual supply in previous periods, to net virtual demand in the second quarter.

Figure 2.1 shows the monthly quantities of both virtual demand and supply offered and cleared in the market. Figure 2.2 illustrates an hourly distribution of the offered and cleared volumes over the second quarter. As shown in these figures:

- On average, 49 percent of virtual supply and demand bids offered into the market cleared in the second quarter.

- Cleared volumes of virtual demand outweighed cleared virtual supply in the second quarter by around 430 MW on average, whereas virtual supply outweighed virtual demand by around 300 MW on average in the first quarter.

- Virtual demand exceeded virtual supply during peak hours by about 760 MW, while during the off-peak hours virtual supply was greater than virtual demand by 230 MW. In the first quarter, peak hours had fairly balanced quantities of virtual demand and supply.

[14] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market to the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

Figure 2.1 Monthly average virtual bids offered and cleared

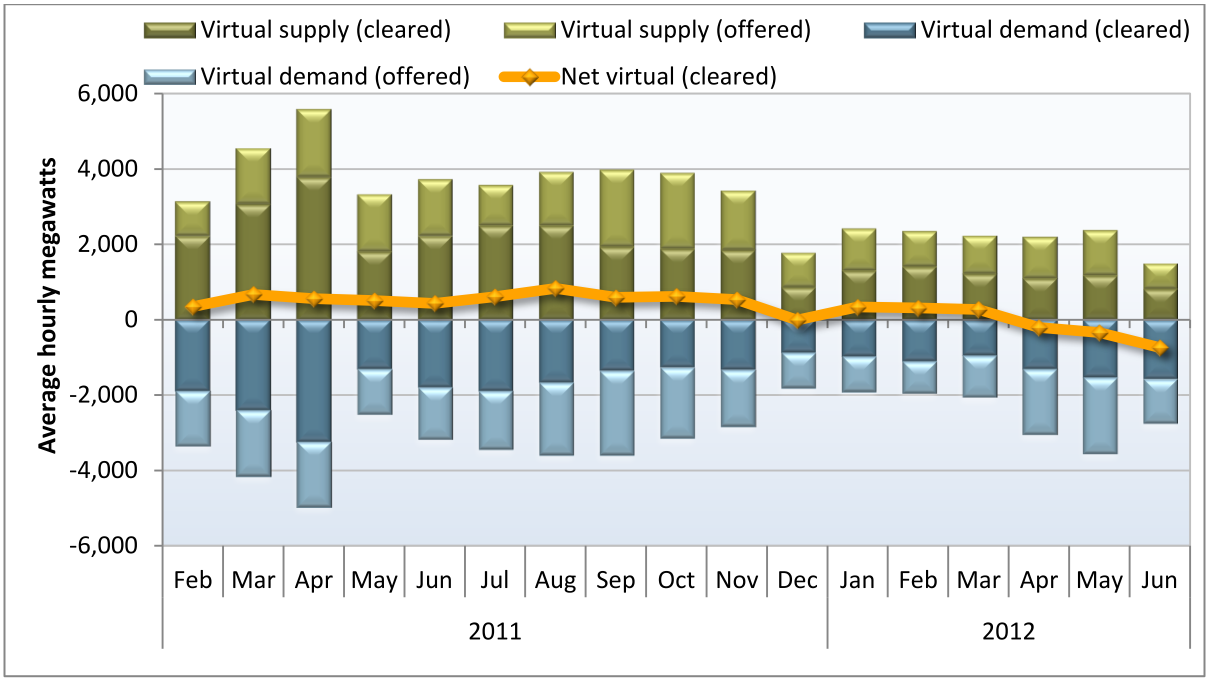


Figure 2.2 Hourly offered and cleared virtual activity (April – June)

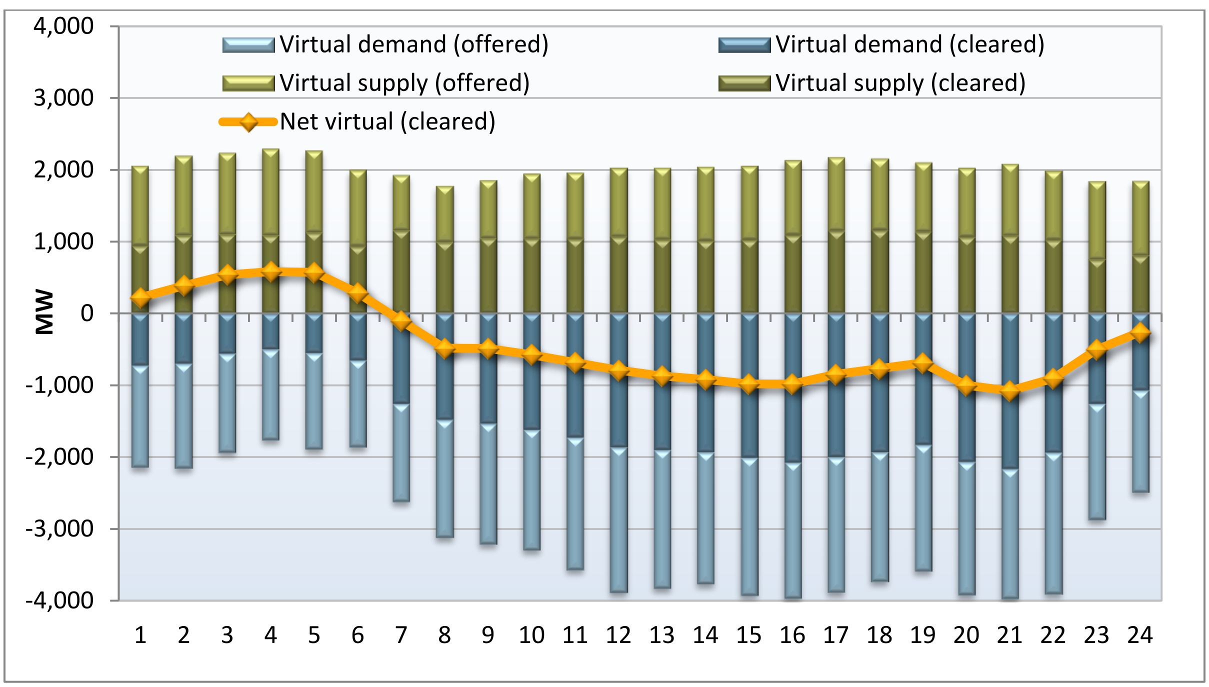
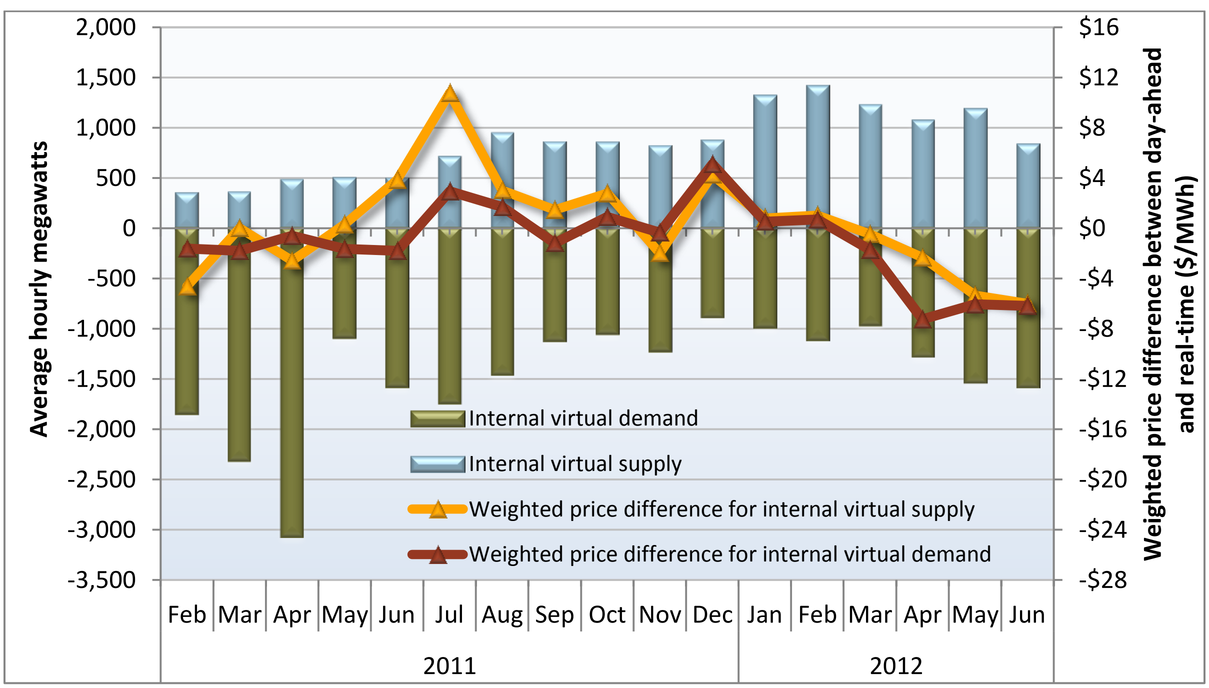


Figure 2.3 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in Figure 2.3 represents the average price difference weighted by the amount of virtual bids clearing at different internal locations. As shown in Figure 2.3:

- Months in which the red line in Figure 2.3 is negative indicates that the weighted average price charged for internal virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand. Internal virtual demand volumes were consistent with weighted average price differences since March 2012. This indicates that virtual demand was profitable in the second quarter.
- Months in which the yellow line in Figure 2.3 is positive indicates that the weighted average price paid for internal virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Beginning in March and continuing through the second quarter of 2012, virtual supply at internal locations were not profitable as the line was negative.
- As noted later in this section, a large portion of the internal virtual supply clearing the market was paired with internal demand bids at different internal locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or profiting from internal congestion within the ISO. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable because of congestion.

Figure 2.3 Convergence bidding volumes and weighted price differences at internal locations



In many hours, particularly during the peak periods in May and June, the net cleared virtual position was consistent with the day-ahead and real-time price differences. Thus, average hourly convergence bidding volumes and prices indicate that net convergence bidding volumes at internal nodes were directionally consistent with converging prices between the day-ahead and real-time markets in many hours and may have helped to converge day-ahead with real-time prices.

Figure 2.4, Figure 2.5 and Figure 2.6 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system marginal energy prices in April, May and June, respectively. The blue bars represent the net cleared internal virtual position, whereas the green line represents the difference between the day-ahead and real-time system marginal energy prices.

- As shown in Figure 2.4, convergence bidding volumes in a majority of hours in April were consistent, on average, with price convergence at internal locations. The net convergence bidding volume direction and the price difference were most consistent between hours ending 7 through 15.
- In May, as seen in Figure 2.5, convergence bidding volumes in 21 hours were consistent, on average, with price convergence at internal locations. Consistency was best in the peak hours. As a result, the net virtual demand position grew even further over the course of the month, which was consistent with average price differences.
- Figure 2.6 shows that in the month of June, convergence bidding volumes again were directionally consistent with differences between day-ahead and real-time prices. The consistency of net cleared convergence bidding volumes with off-peak hourly prices improved while the consistency of volumes with peak prices decreased slightly compared to previous months.

Figure 2.4 Hourly convergence bidding volumes and prices – April

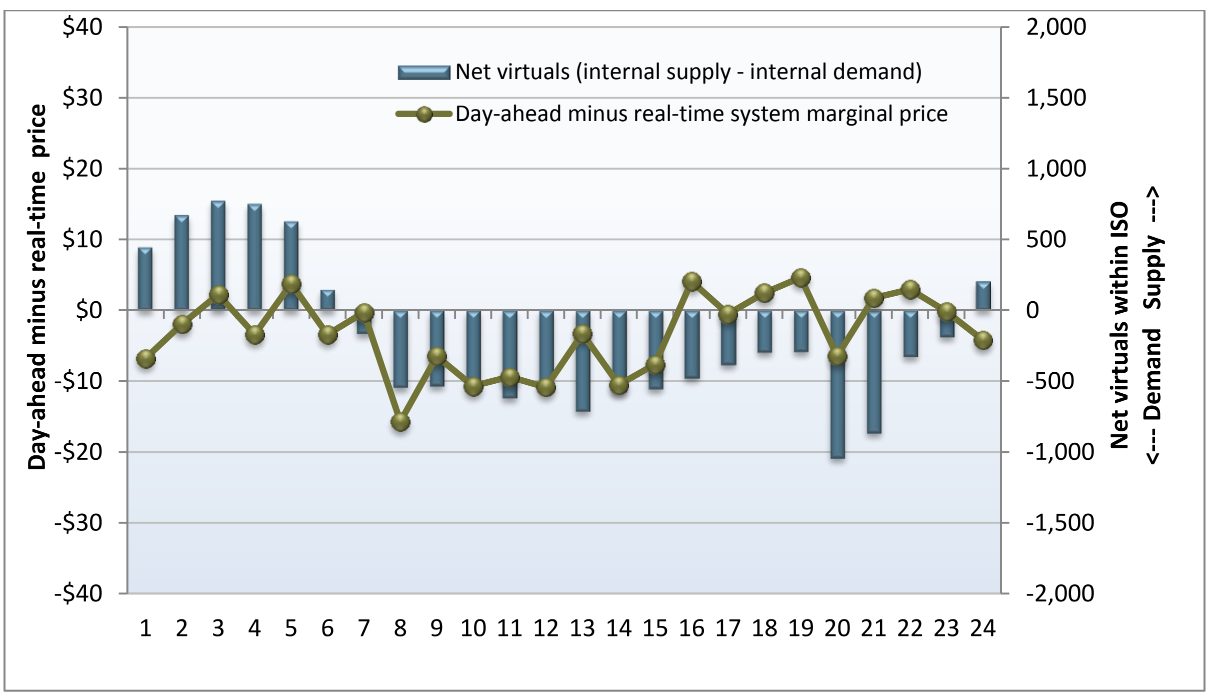


Figure 2.5 Hourly convergence bidding volumes and prices – May

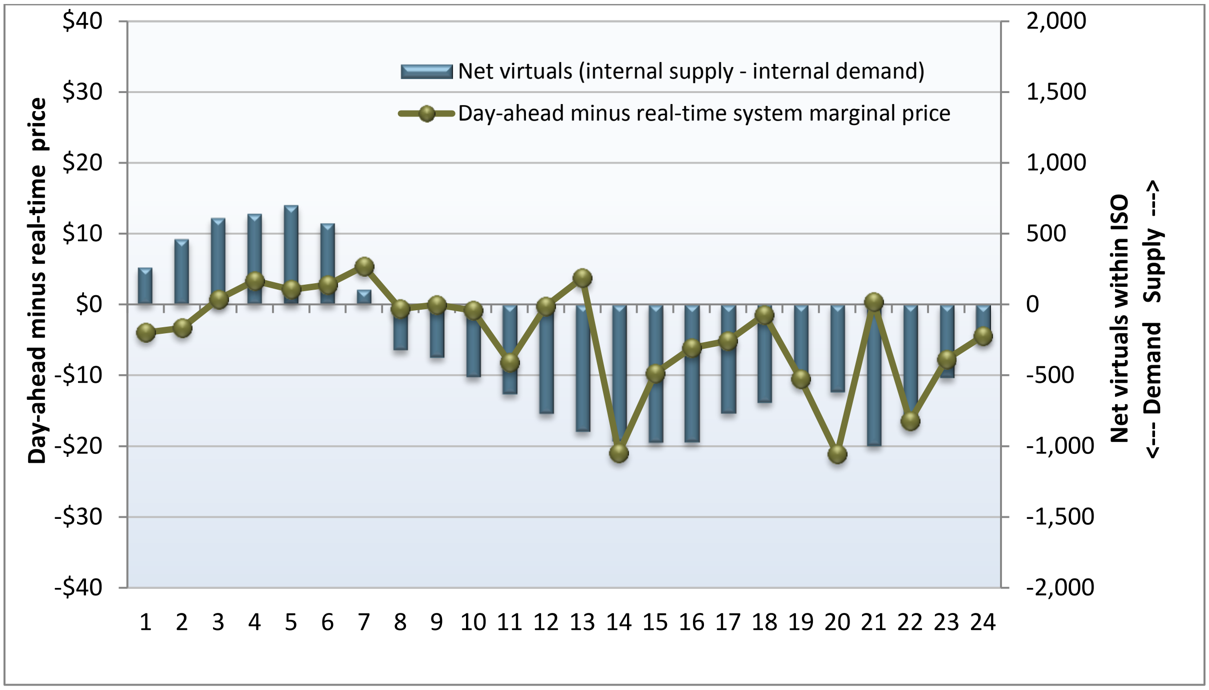
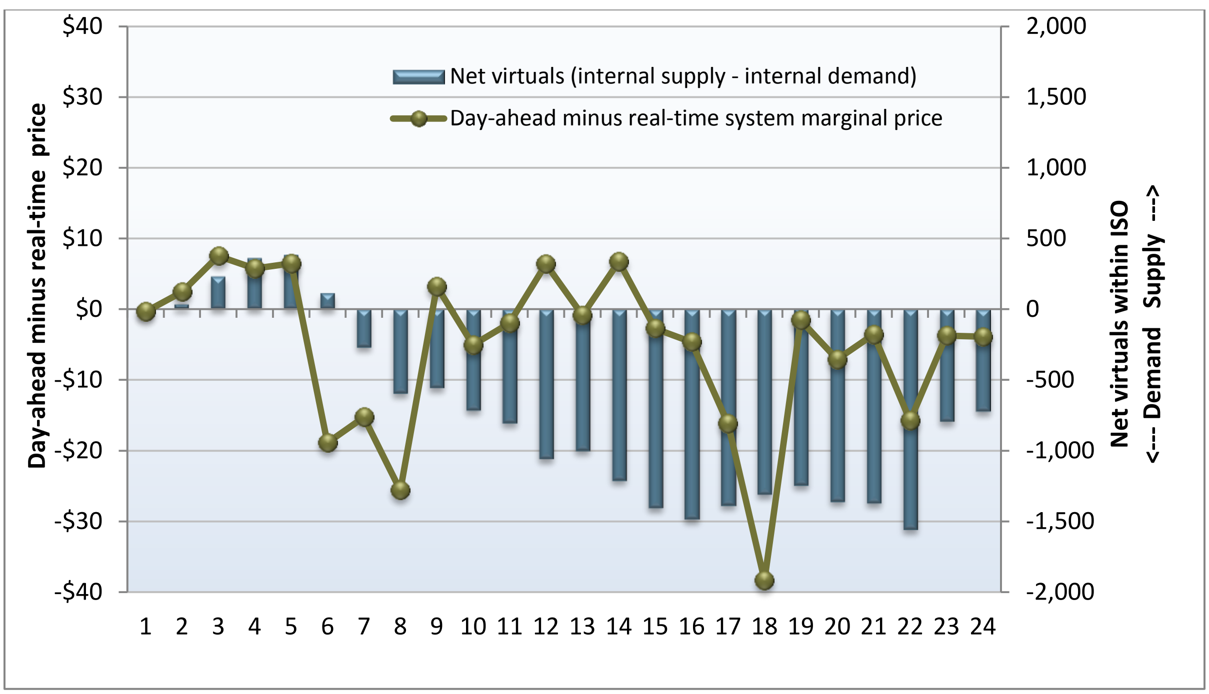


Figure 2.6 Hourly convergence bidding volumes and prices – June



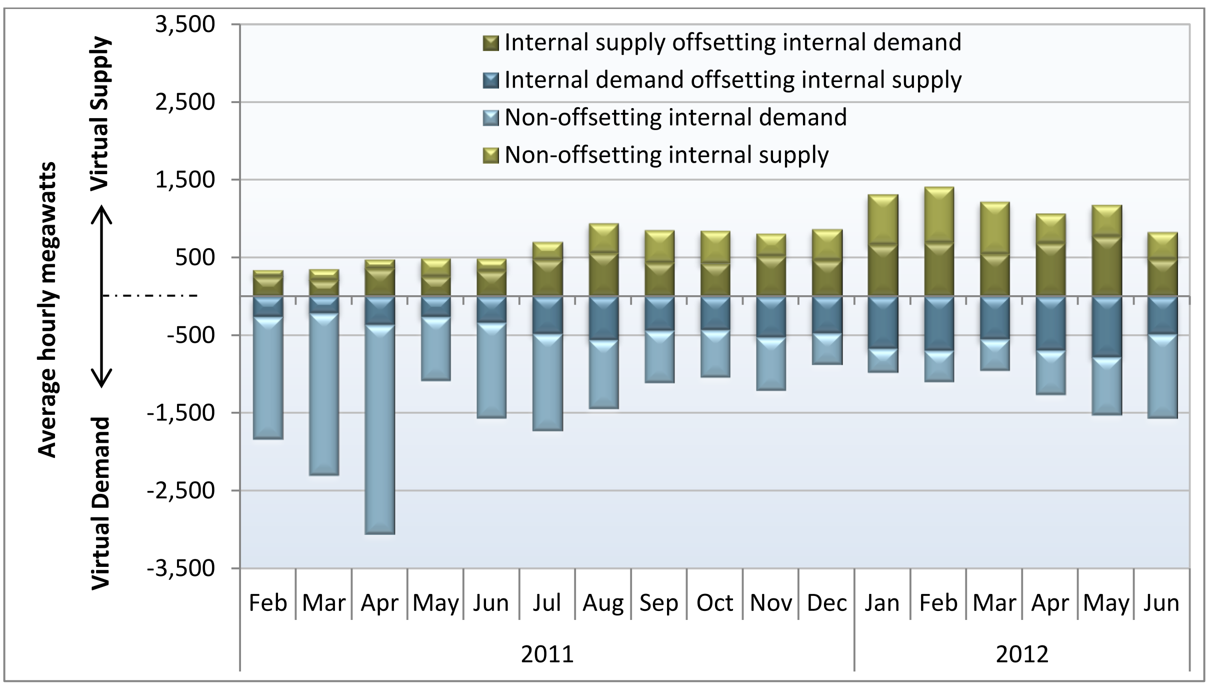
Offsetting virtual supply and demand bids at internal points

Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO by placing virtual demand and supply bids at different internal locations during the same hour.

Figure 2.7 shows the average hourly volume of offsetting virtual supply and demand positions at internal locations. The dark blue and dark green bars represent the average hourly offset between internal demand and internal supply by the same participants.[15] The light blue bars represent the remaining portion of internal virtual supply that was not offset by internal virtual demand by the same participants. The light green bars represent the remaining portion of internal virtual demand that was not offset by internal virtual supply by the same participants.

As shown in Figure 2.7, this type of offsetting virtual position at internal locations accounted for an average of about 650 MW of demand offset by 650 MW of virtual supply at other locations per hour in the second quarter. These offsetting bids represent about 70 percent of all cleared internal virtual bids. This suggests that since suspension of virtual bidding on inter-ties virtual bidding has been heavily used to hedge or profit from internal congestion.

Figure 2.7 Average hourly offsetting virtual supply and demand positions by same participants



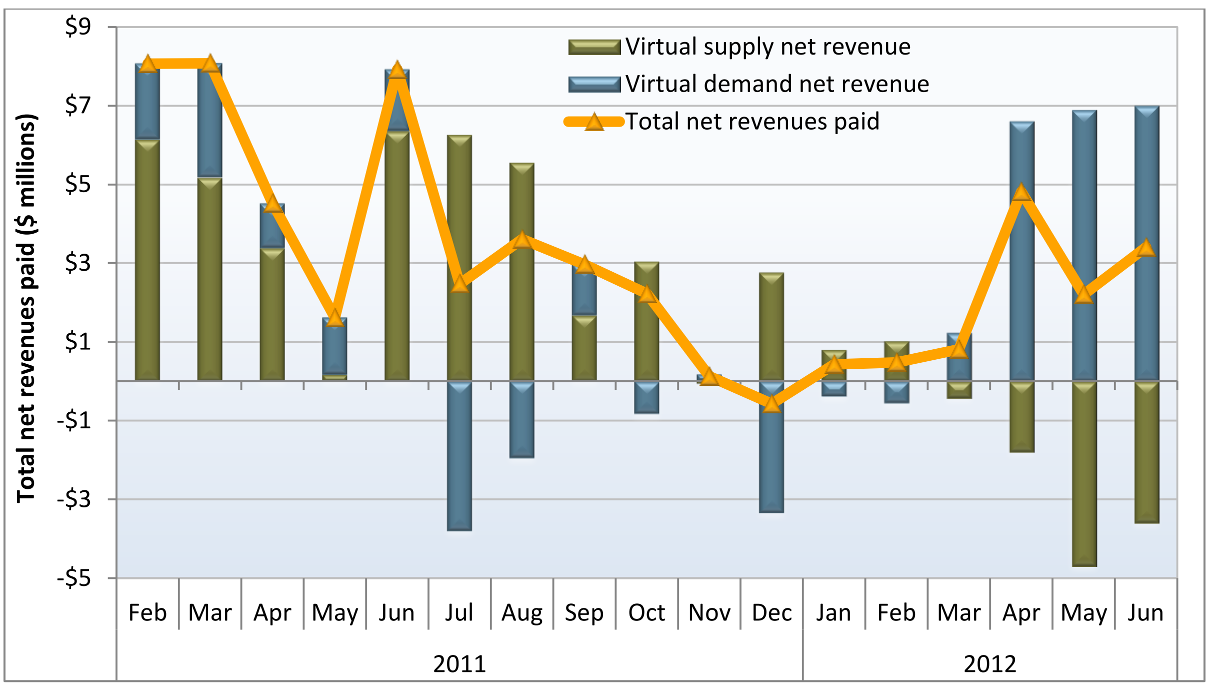
[15] When calculating the offset between each participant's accepted virtual supply and demand bids at internal points each hour, we did not include the portion (if any) of the participant's internal virtual demand bids that were offset by accepted virtual import bids by that participant in the months before virtual bidding at the inter-ties were suspended. This was done to avoid any potential double counting of internal virtual demand as offsetting virtual imports and virtual supply within the ISO during the same hour.

2.2 Convergence bidding payments

Figure 2.8 shows total monthly net payments for accepted virtual supply and demand bids. This figure shows the following:

- Virtual demand positions were consistently profitable in the second quarter. Between March and June, the higher frequency of real-time price spikes increased virtual demand revenues (see Section 1.1 for details).
- Since March, virtual supply bids were no longer profitable. This trend reflects that real-time prices (or congestion) were higher than day-ahead prices beginning in March 2012.
- Total net revenues paid to virtual bidders increased from the first to the second quarter of 2012. Total net revenues paid were higher in the second quarter because of the increased frequency of real-time price spikes (see Section 1.1 for further detail).
- In the second quarter of 2012, net revenues paid to convergence bidding entities totaled around $10 million. These payments were driven primarily by virtual demand revenues of $20 million, which was offset by revenue losses on virtual supply bids of about $10 million. As noted above, the virtual supply bids may be related to an attempt to arbitrage congestion, with one side of the congestion making money and the other side losing money.

Figure 2.8 Total monthly net revenues paid from convergence bidding



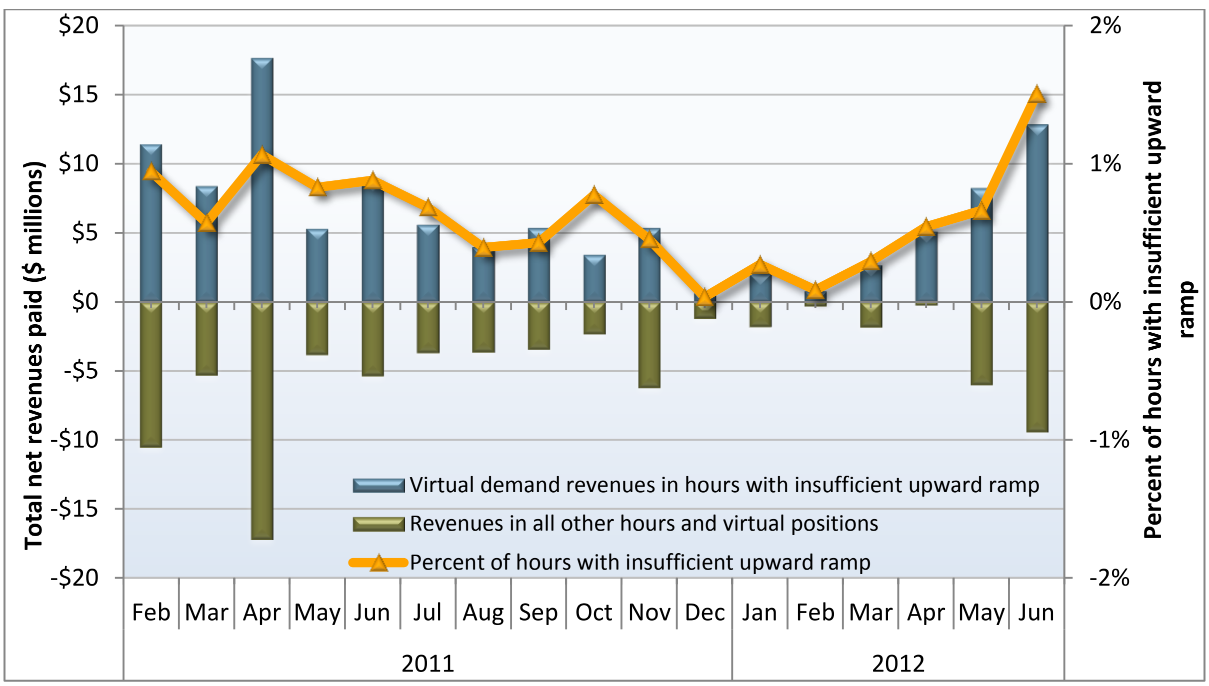
Net revenues at internal scheduling points

In the first quarter, virtual demand accounted for about 44 percent of cleared bids at internal locations; in the second quarter it increased to 59 percent. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Historically, almost all net revenues paid for these internal virtual demand positions have resulted from a relatively small portion of intervals when the system power balance constraint becomes binding because of insufficient upward ramping capacity or with congestion.

Figure 2.9 compares total net revenues paid out for internal virtual bids during hours when the power balance constraint was relaxed because of short-term shortages of upward ramping capacity with the overall net revenues of internal virtual bids during all other hours. As shown in Figure 2.9:

- Although upward ramping capacity was insufficient in about 1 percent of the hours in the quarter, these hours accounted for all net revenues paid for internal virtual demand. Revenues paid for virtual demand during these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. In fact, having a single 5-minute interval price spike can yield enough aggregate revenue to compensate for losses in the remaining hours of the day.
- During the other 99 percent of intervals when sufficient ramping capacity was available, virtual demand bids were highly unprofitable. Since February 2012, the frequency of real-time price spikes has increased. As a result, the revenues of internal virtual demand bids exceeded $12 million in June. As noted earlier (Section 1.1), the frequency of real-time price spikes increased mostly because of congestion and upward ramping shortages.

Figure 2.9 Net revenues paid for convergence bids at internal scheduling points



These price spikes are typically associated with brief shortages of ramping capacity and congestion. In theory, virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of internal virtual demand on real-time price spikes appears to have been limited by the fact that any additional capacity available to convergence bidding may not be enough to resolve congestion or the short-term ramping limitations. This is further exacerbated by the hour-ahead market, which does not reflect the same system conditions and reduces net imports, decreasing the benefits of additional capacity added in the day-ahead market.

Also, in the event of over-generation, real-time prices can be negative, but rarely fall below the bid floor of -$30/MWh. This diminishes the risk of market participants losing substantial money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

2.3 Changes in unit commitment

If physical generation resources clearing the day-ahead energy market are less than the ISO forecasted demand, the residual unit commitment ensures that enough additional capacity is available to meet the forecasted demand. Total direct residual unit commitment costs, which are the residual unit commitment clearing price times the non-resource adequacy capacity cleared in each hour, were around $21,000 in the second quarter of 2012, down from $350,000 in the first quarter of 2012. Bid cost recovery payments for capacity committed in the residual unit commitment process, which account for start-up and minimum load costs for units and real-time revenues, were around $330,000 in the second quarter of 2012, down from $1.1 million in the previous quarter.

As noted above, the amount of cleared virtual demand increased significantly in the second quarter relative to previous quarters. The increase in virtual demand caused a higher amount of generation to clear in the day-ahead market. Because of the higher amount of capacity scheduled in the day-ahead market, less capacity was added by the residual unit commitment process. Therefore, the amount of direct residual unit commitment costs and bid cost recovery payments declined.

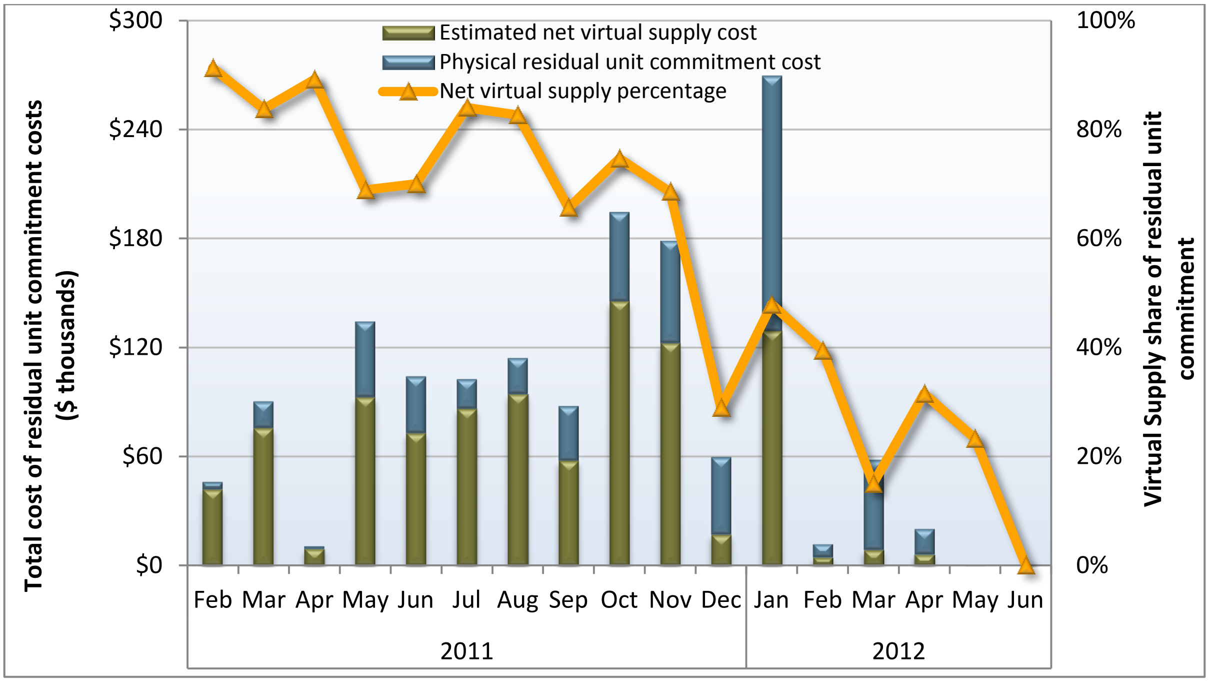
The residual unit commitment adds more capacity to meet differences between forecasted and bid-in demand, to offset the loss of virtual supply and to meet additional local reliability needs. DMM has estimated the share of the total residual unit commitment cost that is attributable to virtual supply by reviewing the factors that led to residual unit commitment and comparing the virtual supply as a percentage of the total.

Figure 2.10 compares the relationship between the cost of the residual unit commitment and the share of net virtual supply. The blue bars represent the estimated physical portion of the residual unit commitment cost, whereas the green bars represent the estimated cost attributed to the net virtual supply. The yellow line illustrates the share of net virtual supply. Figure 2.10 shows the following:

- In 2011, approximately 73 percent of the residual unit commitment costs were attributed to the virtual supply. At that time, the overall net virtual position was virtual supply from the inter-ties.

- In 2012, the residual unit commitment costs were high in January, but dropped afterwards. This change was consistent with the shift from net virtual supply to net virtual demand. As a result, the share of net virtual supply decreased to 26 percent in the first half of 2012.

Figure 2.10 Virtual supply share of total residual unit commitment cost



3 Special Issues

3.1 Real-time flexible ramp constraint performance

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch markets. The constraint is only applied to internal generation and proxy demand response resources and not to external resources.[16] The total payments for flexible ramping resources during the first six months of the year were around $14.8 million.[17] For sake of comparison, costs for spinning reserves totaled about $12 million during the same period.

Application of the constraint in the 15-minute real-time pre-dispatch market ensures that enough capacity is procured to meet the flexible ramping requirement. The requirement is currently set to around 300 MW, down from a default level of 450 MW in the first quarter based on the observed utilization of the flexible ramping capacity in the real-time market. The flexible ramping constraint was implemented to account for the non-contingency based variations in supply and demand between the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch. The additional flexible ramping capacity is designed to supplement the existing non-contingent spinning reserves in the system in managing these variations.

The ISO procures the available 15-minute dispatchable capacity from the available set of resources in the 15-minute real-time pre-dispatch run. If there is sufficient capacity already online, the ISO does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO can commit additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. The short-start units can be eligible for bid cost recovery payments in real-time.[18] A procurement shortfall of flexible ramping capacity will occur where there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute real-time pre-dispatch.[19] As shown below, payments at such times accounted for more than half of flexible ramping costs.

Analysis of the flexible ramping constraint

Since implementation, DMM has monitored the daily flexible-ramping constraint activity and cost. As part of this analysis, DMM has provided a monthly summary of the overall flexible ramping constraint

[16] See the December 12, 2011 FERC order for ER12-50-000 at: http://www.caiso.com/Documents/2011-12-12_ER12-50_FlexiRamporder.pdf.

[17] On July 27, 2012, the ISO filed an offer of settlement for the flexible ramping constraint. See the following for further information: http://www.caiso.com/Documents/July272012Offer-SettlementRegarding-ISOFlexibleRampingConstraintAmendment-DocketNoER12-50-000.pdf.

[18] Further detailed information on the flexible ramping constraint implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

[19] The penalty price associated with procurement shortfalls is set to just under $250.

activity and a summary of the hourly compensation profile to generators for providing flexible-ramping capacity.

Table 3.1 provides a review of the monthly flexible ramping constraint activity in the 15-minute real-time market since the beginning of 2012. The table highlights the following:

- The flexible ramping constraint binding frequency has varied since implementation. The number of binding intervals spiked to about a quarter of the total 15-minute intervals during the months of April and May. This increase was due to the lack of available ramping capacity in the system. The lower online capacity was a result of a combination of low seasonal load during the second quarter and the high level of generation from hydro and other renewable resources in the footprint.
- The frequency of procurement shortfalls peaked in May at over 6 percent of all 15-minute intervals, about one quarter of the intervals in which the flexible ramping constraint was binding.
- The total payments to generators for the flexible-ramping constraint increased from previous months, peaking at over $4 million during the month of May and falling to about $1.5 million in June.

Table 3.1 Flexible ramping constraint monthly summary

Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
Jan	$2.45	17%	1.0%	$38.44
Feb	$1.46	8%	1.3%	$77.37
Mar	$1.90	12%	1.0%	$42.75
Apr	$3.37	22%	1.5%	$39.86
May	$4.11	23%	6.0%	$79.48
Jun	$1.49	13%	2.3%	$52.18

Figure 3.1 shows the monthly flexible ramping payments to generators, which is the total procured volume times the shadow price of the constraint. The green bar shows the payments made during intervals with procurement shortfalls and the blue bar shows the payments in all other periods.

Figure 3.2 shows the hourly flexible ramping payment distribution during the first quarter of the year. As seen in the figure, most payments have been for ramping capacity during the peak hours. Natural gas-fired capacity accounted for about 70 percent of these payments with hydro-electric capacity accounting for most of the remaining 30 percent.

Figure 3.1 Monthly flexible ramping constraint payments to generators

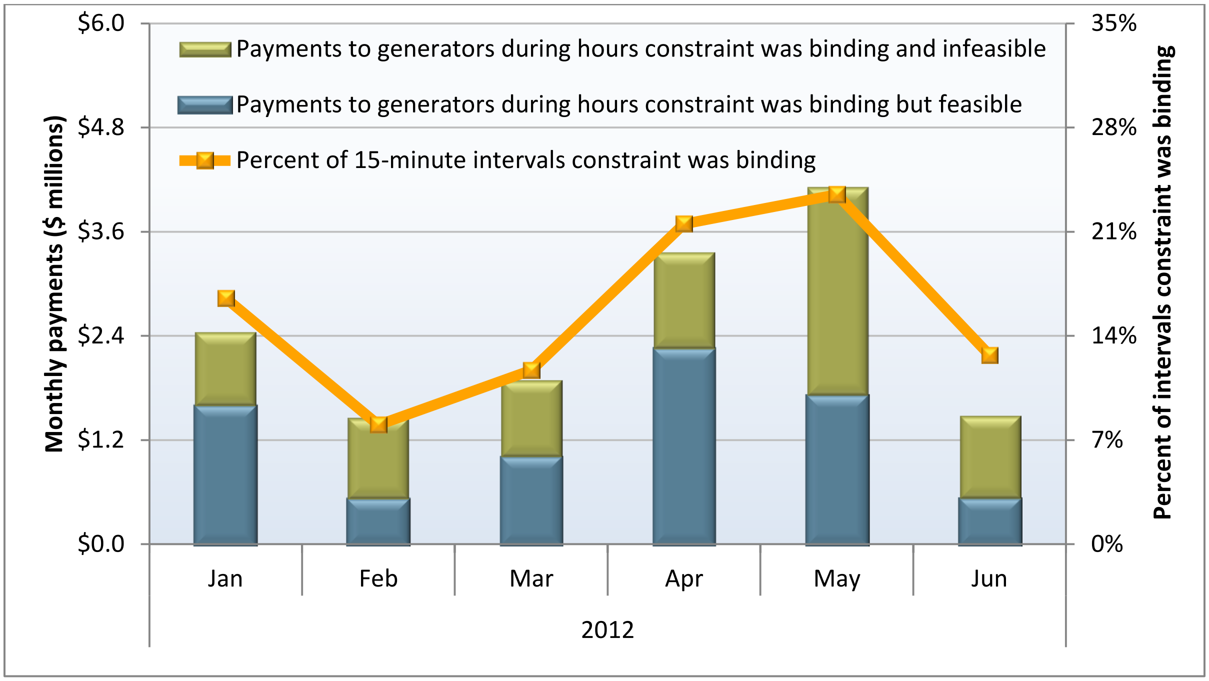


Figure 3.2 Hourly flexible ramping constraint payments to generators (April – June)

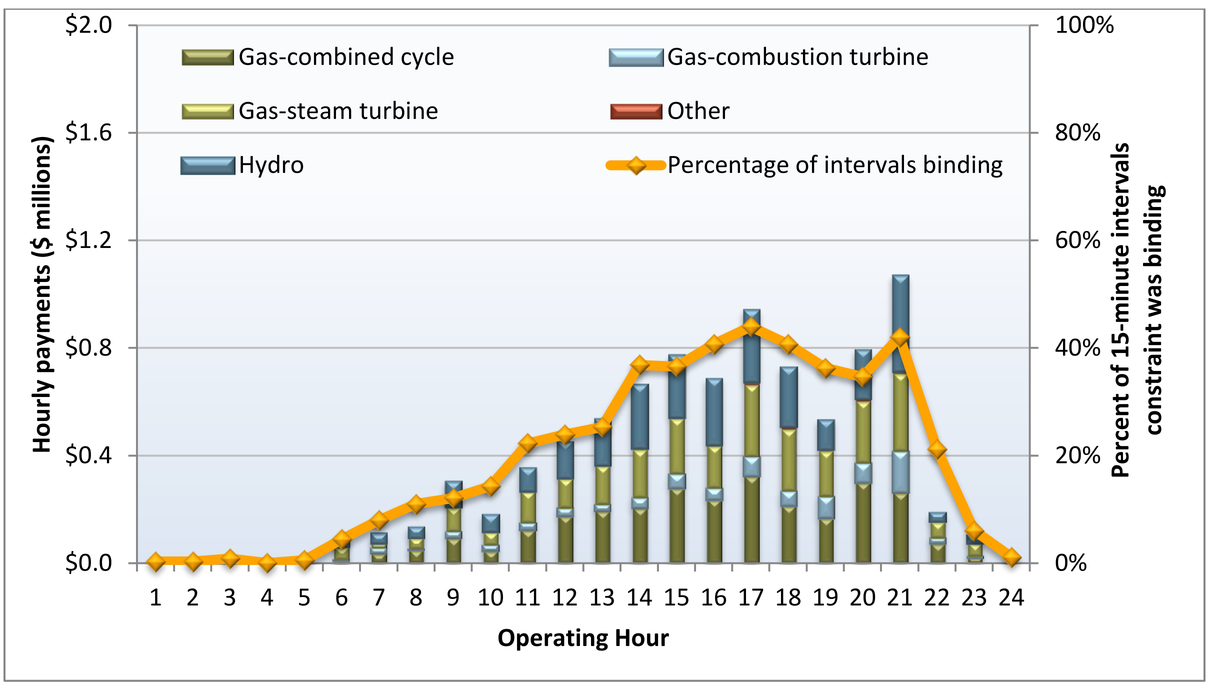
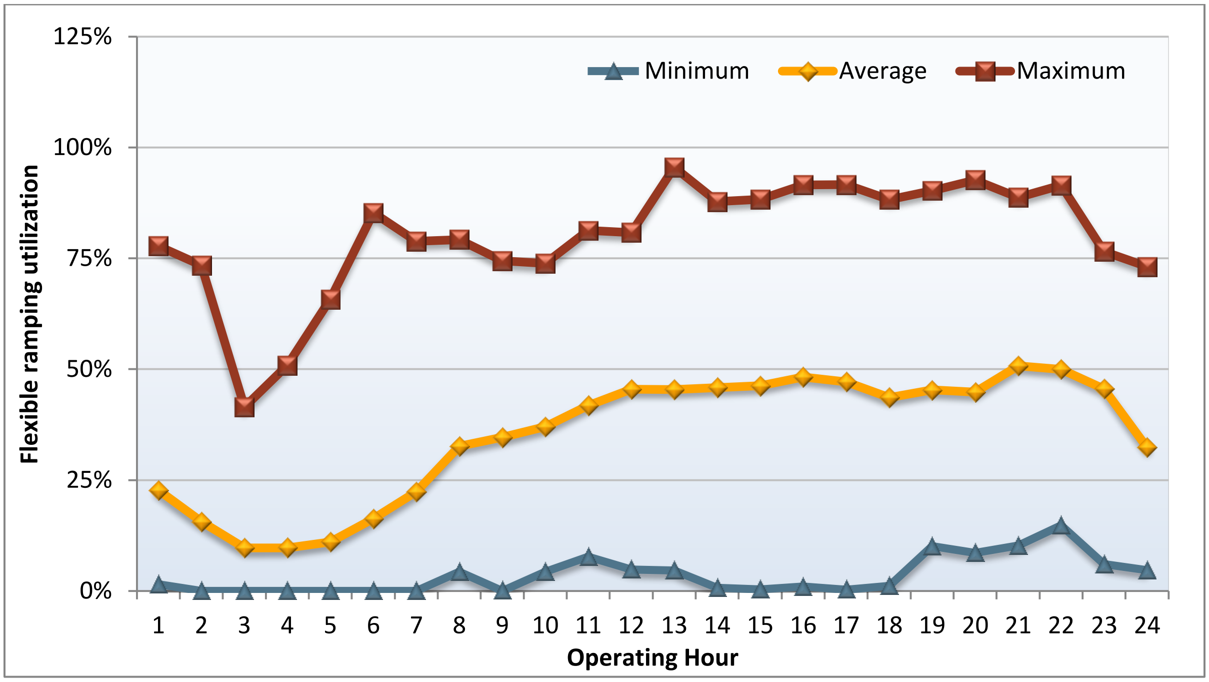


Figure 3.3 Flexible ramping utilization by hour (April – June)



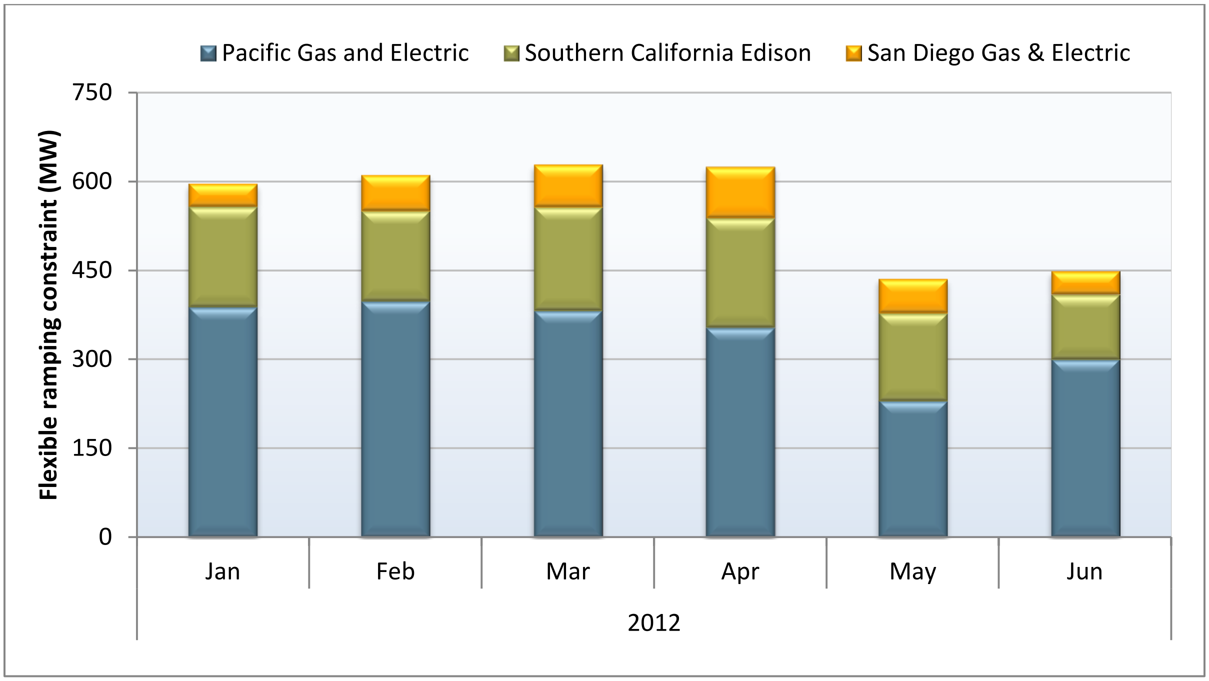
DMM uses the ISO's methodology along with settlement data to calculate the flexible ramping capacity utilization during the second quarter. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch is utilized in the 5-minute real-time dispatch. Figure 3.3 shows the minimum, average and maximum hourly utilization of procured flexible ramping capacity in the 5-minute real-time dispatch. The average utilization of procured flexible ramping varies from about 10 percent in hour ending 3, to a high of about 51 percent in hour ending 21. The utilization is a function of prevailing system conditions, including load and generation levels. The range of hourly average utilization varied from a low of 0 percent to a high of about 95 percent during the quarter. The utilization was at 100 percent at individual 5-minute intervals during load ramping hours and during peak periods. The utilization during the intervals when the flexible ramping constraint was binding was only marginally higher than during non-binding intervals.

Flexible ramping regional procurement

Figure 3.4 shows the procurement of flexible ramping capacity by investor-owned utility area. During the year, over 60 percent of the capacity procured for flexible ramping constraint was in the Pacific Gas and Electric area. This real-time flexible capacity can be deployed during instances of tight system-wide conditions. However, the majority of this capacity cannot be utilized when there is congestion in the southern part of the state.

For example, in the month of June only 39 MW of flexible ramping capacity was procured in the San Diego region, on average. Thus, only a small amount of dispatchable flexible ramping capacity was available to resolve ramping conditions in 5-minute real-time intervals with San Diego congestion. Similarly, during real-time intervals with congestion into the SCE area, only about 110 MW of generation in the month of June was available to ramp when 5-minute real-time congestion occurred.

Figure 3.4 Flexible ramping constraint by investor-owned utility area



DMM continues to recommend that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in the 15-minute real-time pre-dispatch. DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint. In addition, identifying commitment changes caused by the flexible ramping constraint will help in calculating secondary costs related to the flexible ramping constraint. These secondary costs include additional ancillary services payments and additional real-time bid cost recovery payments paid to short-term units committed to deliver energy and displace capacity on other units to provide flexible ramping capacity. Furthermore, DMM recommends that the ISO continue to fine tune the flexible ramping constraint to increase its effectiveness, particularly during periods of congestion.

3.2 Performance of new local market power mitigation procedures

On April 11, 2012, the ISO implemented the first phase of the new competitiveness assessment and mitigation mechanism to address local market power. This included enhancing the competitive path assessment mechanism and mitigation trigger in the day-ahead market. The ISO also incorporated virtual bids into the day-ahead mitigation run and began clearing that market run to bid-in demand instead of forecast load. This section presents analysis of the impact of these changes on the accuracy of local market power mitigation in the day-ahead market.[20]

[20] Further detailed information on the local market power mitigation implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements.aspx.

These enhancements have improved the accuracy of local market power mitigation considerably. One of the factors that creates local market power is congestion. Including convergence bids in the mitigation run and clearing that run to bid-in demand (not forecast demand) has improved accuracy of the mitigation run prediction of where congestion will occur in the actual market run from 45 percent to 93 percent. This increased accuracy is due to more closely aligned model inputs between the mitigation run and the market run.

The move to a dynamic competitive path assessment has also improved the accuracy of identifying where local market power exists. Because the prior approach to determining path competitiveness was performed off-line and well in advance of market operation (up to 4 months), the methodology took a conservative approach accounting for more extreme possibilities. The new approach assesses competitiveness based on actual system and market conditions observed by the market software. The accuracy of the competitive path designations increased from 32 percent to 85 percent. Most of this improvement is attributed to more accurate designations of competitive constraints as the default designation of "non-competitive" is eliminated and the new approach positively tests all binding constraints.

Finally, the new mitigation trigger, which breaks down the price, has improved the accuracy of local market power mitigation by eliminating the unintended mitigation inherent with the prior approach. The new price decomposition method will apply bid mitigation only to resources where the locational marginal price is increased by congestion on an uncompetitive constraint. The prior approach inferred which resources had local market power based on a comparison of dispatch with and without uncompetitive constraints applied in the market model. This indirect approach resulted in a high degree of unintended bid mitigation where the inference of local market power was incorrect.[21] The price decomposition eliminates this unintended mitigation by identifying the opportunity to exercise local market power through direct measurement of the price impact of local market power at each resource.

The impact of mitigation at the resource level can be observed by measuring the change in bid price at the point where the resource is dispatched in the market. In 94 percent of the mitigation instances, the resource's bid price is not impacted. In these cases, the submitted bid was priced at or below the default energy bid at the point of market dispatch. In the remaining 6 percent of instances, the majority of resources have their bid price decreased by $10/MWh or less as a result of mitigation.

Improved accuracy of identification of local market power

Local market power is created by two factors: 1) congestion that limits the supply of imported electricity into the congested area; and 2) insufficient or concentrated control of supply within the congested area. Identification of where local market power will exist based on these two causes was enhanced with this first phase of implementation, which ultimately improved the accuracy of the local market power mitigation.

The first enhancement is in the mitigation run's ability to predict congestion in the subsequent market run where local market power may be exercised. Bid mitigation is applied after the mitigation run is completed, and the set of resulting mitigated bids is then used in the market run. The ability of the mitigation run to accurately predict congestion that occurs in the market run, and therefore identify

[21] See DMM report to the ISO Board of Governors at http://www.caiso.com/Documents/Impact%20assessment%20of%20proposed%20local%20market%20power%20mitigation%20enhancements for more detail.

where local market power may exist, directly impacts the accuracy and effectiveness of the mitigation process.

The first phase implementation also included adding convergence bids to the mitigation run as well as clearing supply against bid-in demand. Previously, no convergence bids were included in the mitigation run and the mitigation run was cleared against forecast load. These two enhancements brought the mitigation run more in line with the actual market run. This resulted in improved congestion prediction and consequently improved identification of where local market power may exist.

The consistency of the occurrence of congestion between the mitigation run and the market run is shown in Table 3.2 for the day-ahead market. Prior to the enhancements, the mitigation run accurately predicted congestion on a constraint only 45 percent of the time and under-predicted congestion nearly as often – 37 percent of the time. Under-prediction reflects under-identification of potential local market power and precludes the mitigation process from further evaluation and application of bid mitigation. These are instances where local market power may exist and be exercised but would not be mitigated.

Table 3.2 Congestion parity between mitigation run and market run (Q2 of 2011 and 2012)[22]

Mitigation Run vs Market Run	2011 Q2	2012 Q2
Consistent	45%	93%
Over-identified	18%	3%
Under-identified	37%	4%

The accuracy of the congestion prediction increased to 93 percent as a result of the mitigation enhancements implemented in April. Moreover, the frequency of under-identification of congestion and potential local market power decreased markedly to 4 percent. While there were other areas of improvement in accuracy that are discussed below, this improvement in congestion prediction represented a considerable increase in the accuracy of local market power mitigation.

Another area where the mitigation enhancements improved accuracy is in evaluating the competitiveness of supply to relieve congestion on binding constraints. While congestion can create the potential for market power to exist, the amount and concentration of control of supply available to meet demand in the congested area determine whether local market power exists as a result of the congestion.

Historically, DMM has performed quarterly competitiveness assessments that have been used in the market model as part of the local market power mitigation process.[23] These studies used historical data and considered a range of possible system conditions that may occur during the period where the path determinations will be used in the mitigation process. Because the study and application of results was

[22] These figures represent instances where internal paths were congested in the mitigation run, the market run, or both. Instances where a line was not congested in either are not included. This is due to the large number of transmission constraints and the relative infrequency of congestion. The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

[23] DMM uses a residual supplier test for the competitiveness assessments. For more detailed description of the residual supplier test applied, see http://www.caiso.com/Documents/WhitePaper-CompetitivePathAssessment.pdf.

forward looking, a more conservative approach to determining competitiveness was taken. A wide range of load and hydro-electric conditions were considered. A failure in any one of the many simulated hours forced a non-competitive designation and any constraint congested less than 500 hours in the past year was automatically deemed non-competitive.

The mitigation enhancements moved the evaluation of competitiveness into the market software so that it is now run in-line with the market. A congested path is deemed competitive unless the residual supplier index, with the three largest effective suppliers removed, is less than one. This dynamic competitive path assessment leverages up-to-date information regarding system and market conditions, and provides a more targeted and accurate assessment of the supply conditions in areas where congestion may have created local market power.

There were about 5,300 binding constraint hours in the mitigation run between April 11 and June 30. The dynamic competitive path assessment deemed 79 percent of these instances competitive and the remaining 21 percent non-competitive. A comparison of path designations between the static and dynamic approaches is presented in Table 3.3.[24] These are compared to the competitiveness as measured in the market run using the same methodology as the dynamic competitive path assessment. These results indicate that the dynamic competitive path assessment is more accurate in assessing competitive paths. For instance, the accuracy rate for competitive designations for the dynamic competitive path assessment was 98 percent (51 percent binding were deemed competitive whereas 52 percent binding measured competitive).

Also, the dynamic competitive path assessment performs comparably to the static approach in assessing non-competitive paths, and is 85 percent accurate overall, where the static approach was only 32 percent accurate.

The figures in Table 3.3 are color coded to indicate accuracy or the nature of the inaccuracy. Green indicates an accurate path designation in the mitigation run compared to our measurement of competitiveness in the actual market run. Blue indicates the mitigation run deemed the constraint non-competitive when it was measured as competitive in the actual market run. These instances reflect the potential for unnecessary mitigation since the constraint was measured competitive in the actual market run. Orange indicates the mitigation run deemed the constraint competitive when it was measured in the actual market run to be non-competitive. These instances reflect the potential for under-identification of local market power and potential under-mitigation.

As indicated in the table, the dynamic competitive path assessment results in considerably more accurate path designations, and consequently more accurate application of local market power mitigation, than does the static approach. Most of the improvement in accuracy arises from fewer instances where the assessment falsely designated a path non-competitive.

[24] This comparison is intended to provide an indication of the accuracy of the competitiveness designation that stems from the mitigation compared to the competitiveness observed in the actual market run. We note two important aspects that may affect the parity of path designations. First, the mitigation run uses unmitigated bids and the actual market run uses bids that were mitigated. This may change the relative economics of individual resources between the two runs. This, in turn, may result in a different dispatch which can change the amount of available capacity that is used in the residual supply index calculation and ultimately result in a different path designation. Second, DMM calculates the residual supply index for the market run where the calculation for the mitigation run is performed by the market software. The DMM calculation is designed to mirror the calculation performed in the market software and perform when benchmarked, however slight differences may exist. If the residual supply index is different between the two runs but both figures have the same relationship to the threshold of one then both path designations will be the same.

Table 3.3 Static and dynamic path designations compared to measured competitiveness in the market run (April 11 – June 30, 2012)[25]

			As measured in the market run	
			Competitve	**Non-competitive**
As measured in the mitigation run	**Static CPA**	Competitive	1%	17%
		Non-competitive	51%	31%
			52%	48%
	Dynamic	Competitive	51%	14%
		Non-competitive	1%	34%
			52%	48%

Improvement in the application of bid mitigation

Another mitigation enhancement feature was the improvement of the mitigation trigger. This trigger, which breaks down the price, has improved the accuracy of local market power mitigation by eliminating the unintended mitigation inherent with the prior approach. The price decomposition method will apply bid mitigation only to resources where the locational marginal price is increased by congestion on an uncompetitive constraint. The prior approach inferred which resources had local market power based on a comparison of dispatch with and without uncompetitive constraints applied in the market model. This indirect approach resulted in a high degree of unintended bid mitigation where the inference of local market power was incorrect. The price decomposition eliminates this unintended mitigation by identifying the opportunity to exercise local market power through direct measurement of the impact of local market power on prices at each resource. The result is that all bid mitigation is applied to resources that have been positively identified as having local market power.

Impact of mitigation on resource bids

Although a resource may be subject to bid mitigation, the mitigation may not have a meaningful impact on the resource's bid price. Further, even if the bid price is affected, this may not have an effect on market prices. This section presents information about the impact of bid mitigation on an individual resource's bid curves. Mitigation will lower the bid price to the higher of the resource's default energy bid or the calculated competitive price.[26] Mitigation may have no impact on a resource's bid price in

[25] Data reflected in this table include instances where a constraint was binding in both the mitigation run and the market run.

[26] The calculated competitive price is a price calculated by the mitigation process that removes the impact that local market power may have had on the locational price. The methodology considers both direct and indirect impacts of local market power and is described in more detail at http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements.pdf.

instances where the bid price is below the mitigation floor. In fact, bid mitigation has no material impact on the resource's bid price in nearly all instances where bid mitigation is applied. Generally, this has been the result of predominantly competitive bidding where resources are submitting offers at or below their competitive bid curves known as default energy bid curves.[27]

During the study period, there were 29,576 unit hours where bid mitigation was applied. In 94 percent of these instances, there was no meaningful change in the bid price.[28] Table 3.4 shows the distribution of decrease in bid price for the remaining 1,779 unit-hours where bid mitigation did result in a change in bid price.

Table 3.4 Decrease in bid price resulting from mitigation (includes only non-zero impacts)

Input bid change	Unit-hours	# of units
($0-$5]	815	30
($5-$10]	224	22
($10-$25]	68	12
($25-$100]	199	12
$100+	473	11

In the majority of instances, the decrease in bid price resulting from mitigation was $10/MWh or less, and about 80 percent of those were $5/MWh or less. There were instances where higher priced bids were lowered by mitigation, which resulted in bid price decreases of over $25/MWh. These intervals represent about 38 percent of the total intervals where mitigation had a measurable effect on bid price. The impact of mitigation on market price is a companion measure useful in evaluating the effectiveness of any mitigation methodology. More detailed analysis including effect on market price and evaluation of the real-time market will be included in a subsequent report.

3.3 Compensating injections

In July 2010, the ISO re-implemented an automated feature in the hour-ahead and real-time software to account for unscheduled flows along the inter-ties. This feature accounts for observed unscheduled flows by incorporating compensating injections into the market model. These are additional megawatt injections and withdrawals that are added to the market model at various locations external to the ISO system. The quantity and location of these compensating injections are calculated to minimize the difference between actual observed flows on inter-ties and the scheduled flows calculated by the market software. The software re-calculates the level and location of these injections in the real-time pre-dispatch run performed every 15 minutes. The injections are then included in both the hour-ahead and 5-minute real-time market runs.

[27] The default energy bid is used as a reference bid for internal resources. It may be determined under any of three different methodologies, all of which are designed to reflect a competitive bid.

[28] We define a meaningful bid price change as one measured at the point of market dispatch. It is unlikely that a bid price change at an output level further away from the market dispatch would have had an impact on the dispatch, locational price, or the revenue for that resource.

Before implementing this feature, the ISO identified that if the net quantity of compensating injections – or the difference of the injections and withdrawals added to the market model – is significantly positive or negative, this can create operational challenges if the net compensating injections were assumed to persist because of the impact this has on the area control error (ACE). The ACE is a measure of the instantaneous difference in matching supply and demand on a system-wide basis. It is a critical tool for managing system reliability.

To avoid creating problems managing the ACE, a constraint was added to the software that limits the net impact of compensating injections to an absolute difference of no more than 100 MW. This limitation is imposed by applying a discount factor to the compensating injections calculated by the software as this absolute difference increases beyond this 100 MW threshold. This reduces the compensating injections at each location if the overall net system-level compensating injections exceed this 100 MW threshold. This discount factor is set to 0.3 for absolute net compensating injections between 100 MW and 335 MW. Compensating injections are cancelled when absolute net injections increase above 335 MW.

As a result of this constraint, there can be three distinct modes or statuses of compensating injections.

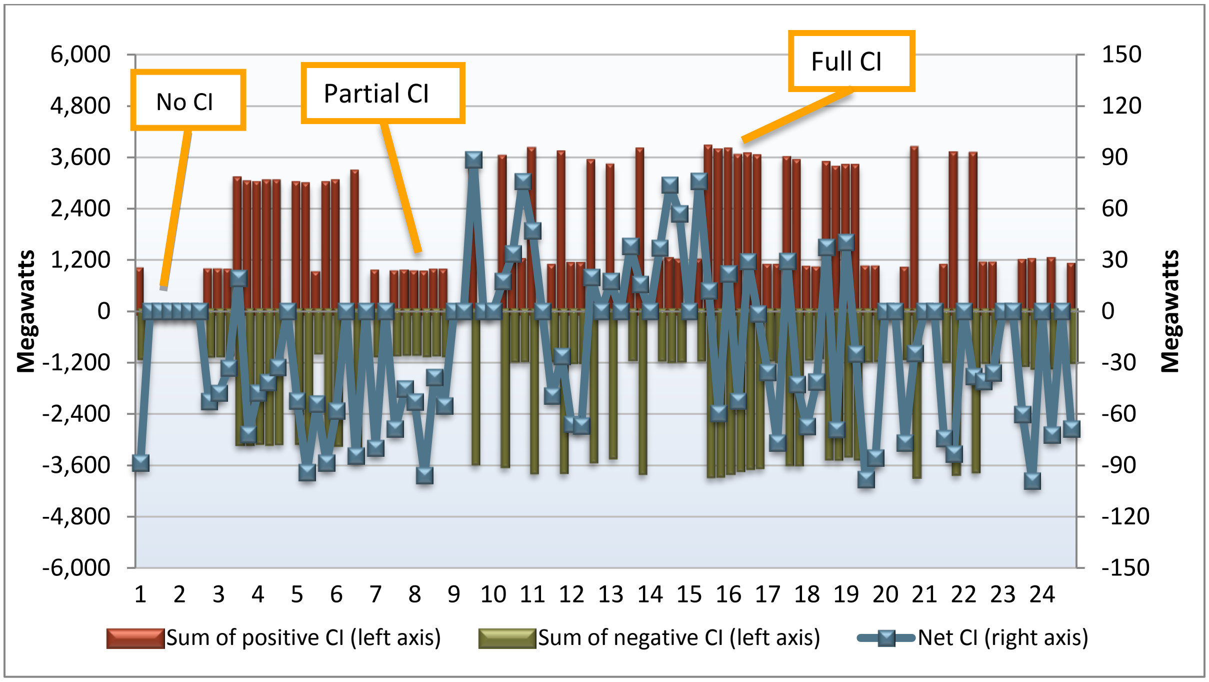
- **Full compensating injections** — This is when compensating injections are fully enabled and are not limited by the discount factor.
- **Partial compensating injections —** This is when the compensating injections are limited by the discount factor.
- **Compensating injections turned off —** This is when the compensating injections are turned off because the net compensating injections value would have been too high relative to the area control error to resolve the solution.

Prior analysis by DMM indicated the accuracy of the modeled transmission flows relative to the actual flows is only improved when this software is consistently operating with full compensating injections in effect. Moreover, DMM has expressed concern that if compensating injections are frequently switched from these different modes, this may create sudden and frequent changes in modeled flows that could in some cases decrease the efficiency of the congestion management and potentially create operational challenges.[29]

Figure 3.5 displays the 15-minute status of compensating injections for a representative day during the second quarter to highlight how the status of compensating injections changed over the course of a day. Recently, the ISO has determined that the frequent variability of compensating injections, as depicted in Figure 3.5, has resulted in operational challenges around certain constraints. As a result, the ISO has begun to regularly track the performance of compensating injections and is gradually modifying the controlling parameters to reduce the variability and improve the performance of this feature. The changes include increasing the absolute difference limitation threshold from 100 MW to 150 MW, increasing the level of where absolute net injections are cancelled from 335 MW to 400 MW, and increasing the discount parameter from 0.3 to 0.5 for absolute net compensating injections between 150 MW and 400 MW.

[29] For an in-depth analysis of compensating injections see DMM's *2011 Annual Report on Market Issues and Performance***,** April 2012, Section 8.4, http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

Figure 3.5 Compensating injection levels (May 31, 2012)



Attachment D –

Assessment of the Impact of Proposed Local Market Power

Mitigation Enhancements (Feb. 9, 2012)

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

Assessment of the Impact of Proposed Local Market Power Mitigation Enhancements

White Paper

Department of Market Monitoring

February 9, 2012

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Contents

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Executive Summary

The analyses discussed below was performed to assess the impact of the local market power mitigation (LMPM) enhancements that the CAISO proposes in this proceeding and to supplement the discussion of those enhancements contained in the Direct Testimony of Jeffrey D. McDonald submitted in the proceeding.

To perform the analyses, the proposed dynamic competitive path assessment approach and an approximation of the proposed locational marginal price "decomposition" methodology (decomposition methodology) for resource bid mitigation under the LMPM enhancements were applied to historical market outcomes for both the day-ahead and real-time markets. The analyses focus specifically on the three-month period from July 1, 2011, through September 30, 2011. The analyses indicate the following:

- In the day-ahead market, the dynamic competitive path assessment greatly improves the accuracy of path designations, and reduces the frequency with which paths are designated as uncompetitive.
- In the day-ahead market, including bid-in demand and convergence bids in the mitigation process will potentially have a dramatic impact on the accuracy of predicting congestion in the mitigation run, and consequently improve the accuracy of local market power mitigation.
- In the day-ahead market, the net impact of implementing the new mitigation trigger improves overall accuracy and reduces the frequency of mitigation by 13 percent. This is largely due to the elimination of unintended mitigation.
- For HASP during the first phase, the net impact of implementing the new mitigation trigger resulted in a 48 percent decrease in the frequency of mitigation – largely from the elimination of the high degree of unintended mitigation.
- Full implementation in the real time market improved the accuracy of identification of local market power – attributed to the addition of mitigation in the pre-dispatch run after HASP. These gains come from both improved congestion prediction as well as more accurate assessment of the available supply to relieve congestion.
- Improved accuracy and reduced frequency (compared to the current approach) of mitigation estimated for HASP is expected to persist during full implementation in the real time market.

Comparison of Current and Proposed Approaches

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Identifying Local Market Power

Local market power is created when transmission constraints limit the supply available to serve load in a local area to the point where there is limited capacity and/or few suppliers. Both the current and proposed approaches for identifying where local market power exist employ a pivotal supplier test. However both the timing of the calculations and the methodologies differ between the two approaches.

The current process for determining which transmission constraints do not have a competitive supply of counter-flow is referred to as the *competitive path assessment*. This determination is made four times a year through an analysis of the sufficiency of supply of counter-flow for internal transmission constraints that have been congested (or have been managed for congestion) in over 500 hours in the most recent 12 months. The study is performed by DMM staff and assesses path competitiveness by simulating the sufficiency of supply for counter-flow to congested constraints when capacity from the three largest potentially pivotal suppliers (system-wide or regionally) is withheld from the market.

The test for supply sufficiency, and thus competitiveness, is done for each candidate transmission constraint. If the market simulation used for this study is able to arrive at a solution without the withheld capacity while respecting the limits of the tested transmission constraint, then the test for that constraint under those conditions is passed. If the market simulation must violate the tested transmission constraint to solve, or cannot reach a solution, then the test for that constraint under those conditions is failed. This test is run for various load and hydro conditions based on historical observation. If a tested constraint fails the supply sufficiency test under any of the test conditions, then that constraint is deemed uncompetitive.

Transmission constraints that do not exceed the threshold of 500 hours of congestion in the most recent 12 months are not tested and are deemed uncompetitive by default. These determinations are made four times a year and are static in the sense that they apply until a subsequent study is performed.

The current approach for assessing path competitiveness is performed outside of the execution of the CAISO's market process and the results are used in the market execution process to facilitate identifying and mitigating for local market power.

The proposed approach to dynamic competitive path assessment (DCPA) will be run directly within the market software, and will therefore reflect more refined measures of demand and supply of counter-flow tailored to the market run where it is applied, and will use the most recent market and system information in assessing competitiveness. Technical details regarding the proposed DCPA can be found in the most recent paper published by the ISO[1].

The CAISO currently employs a static competitive path assessment in all of the markets it operates. In stage one of its proposed LMPM enhancements, which will go into effect in the Spring of 2012, the CAISO will implement improvements in how it applies LMPM procedures to resources with the potential to exercise local market power in the day-ahead market and the HASP. In this sage, the CAISO will implement a new dynamic competitive path assessment in the day-ahead market only.

[1] See "Revised Draft Final Proposal – Dynamic Competitive Path Assessment" at http://www.caiso.com/Documents/RevisedDraftFinalProposal-DynamicCompetitivePathAssessment.pdf for a more detailed description.

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In stage two of the proposed LMPM enhancements, which the CAISO anticipates will go into effect in the fourth quarter of 2012, the CAISO will further enhance its LMPM procedures by adding an additional mitigation run as part of its 15-minute real-time unit commitment process. In this second stage, the CAISO will also implement a dynamic competitive path assessment for the HASP and each real-time unit commitment process.

Both the current static competitive path assessment and the proposed dynamic competitive path assessment use a form of pivotal supplier test to evaluate the competitiveness of transmission constraints (sometimes also called paths). However, the approach taken in evaluating the competitiveness of transmission constraints differs considerably under the static competitive path assessment as compared with the dynamic competitive path assessment.

The following is a high-level comparison of the static competitive path assessment and dynamic competitive path assessment.

Static Competitive Path Assessment	Dynamic Competitive Path Assessment
Analysis and path determinations are based primarily on historical information, with resulting designations applied going forward (one to four months forward).	Analysis and path determinations are performed in-line with the market software using resource, transmission, and load information that is also used by the market software in the subject dispatch interval.
Based on simulation that uses hourly schedules for a 24-hour optimization (similar to the day-ahead market).	Based on dispatch interval length for which the assessment is being done. More accurately reflects resource ramp limitations than does the static competitive path assessment.
Withholds all capacity in portfolio of potentially pivotal suppliers.	Adjusts capacity withholding to reflect the interval-specific ramp-limited quantity that could have been withheld (short of full unit outage).
Pivotal suppliers are evaluated and withdrawn from supply on a system-wide basis.	Pivotal suppliers and calculations of the residual supply index are specific to each constraint being evaluated.
Default designation of “uncompetitive” if constraint is not tested.	Tests all binding constraints that are not permanently deemed competitive.

A more detailed description of the current static competitive path assessment can be found on the CAISO website in the CAISO Business Practice Manual for Market Operations (particularly in Attachment

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C of that document), and in the Department of Market Monitoring (DMM) paper entitled "Competitive Path Assessment for MRTU - Final Results for MRTU Go-Live."[2]

Mitigating Local Market Power

The current local market power mitigation mechanism assesses and mitigates local market power in two pre-market LMPM runs. The first of the two LMPM runs clears the market with only competitive constraints enforced in the full network model (competitive constraints run). The resulting dispatch reflects a competitive market outcome absent any impacts from the exercise of local market power. By not enforcing the uncompetitive transmission constraint limits, this set of constraints is not able to bind and create a circumstance where local market power exists.

The second of the two LMPM runs (all constraints run) applies all transmission constraints in the full network model. The dispatch from the all constraints run is compared to the dispatch from the competitive constraints run. Generating resources that were dispatched upward in the all constraints run relative to their competitive constraints run dispatch are presumed to be dispatched upward to manage congestion on an uncompetitive constraint and as such are deemed to have local market power. Bid mitigation is applied to the set of resources that have an all constraints run dispatch greater than their competitive constraints run dispatch. Bid prices are mitigated to a resource-specific reference price curve (default energy bid) but not below the bid price of the resource's highest priced bid segment dispatched in the competitive constraints run.

For the day-ahead market, this mitigation process is performed as part of the 24-hour optimization of integrated forward market (IFM). For the real-time market, this mitigation is done as part of the HASP. Bids mitigated in HASP are then used in the 5-minute real-time market.

The appeal of this approach is that it focuses mitigation on resources that have local market power and are anticipated to be critical for managing any congestion that gives rise to local market power. This approach relies heavily on an underlying assumption that any increase in a unit's dispatch in the all constraints run (compared to its dispatch level in the competitive constraints run) is indicative of local market power due to the need to manage congestion on an uncompetitive constraint.

However, experience under the first few years of the CAISO's nodal market indicates that this underlying assumption is not always valid. There has often been mitigation of generation resources that do not appear to be associated with, or effective in managing congestion on, binding uncompetitive transmission constraints, and therefore do not appear to have local market power.[3] This type of mitigation is unintended and is eliminated by the proposed LMPM trigger. During the study period, approximately 94 percent of the mitigation that occurred in the day-ahead market appeared to be unintended. In this context, unintended refers to a circumstance where (a) a unit was mitigated in an

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[2] This DMM methodology paper is available at http://www.caiso.com/2365/23659ca314f0.pdf. Recent DMM papers presenting path determinations are available at http://www.caiso.com/Documents/Competitive%20path%20assessments%20for%202011

[3] This definition may over-state over-mitigation in cases where the market software observed congestion on an uncompetitive constraint and, as part of its iterative process, increases the dispatch of effective resources to a point where the congestion no longer exists. In this case, the incremental dispatch of effective resources was made under uncompetitive conditions however the uncompetitive constraint is no longer binding, creating the appearance of over-mitigation.

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interval where there were no binding uncompetitive constraints or (b) there were one or more binding uncompetitive constraints however the mitigated unit could not have been effective in relieving congestion on those constraints.

The very high percentage of instances of over-mitigation raises concern with respect to the accuracy of the CAISO's current mitigation process. While inaccuracy is a concern, both the current and proposed bid mitigation mechanisms include a mitigation floor that limits the extent to which a resource's bid price can be mitigated. In both cases, the bid price will not be mitigated below the higher of a calculated competitive price or the resource's default energy bid. This limits the likelihood that market prices resulting from over-mitigation will not reflect at least the resource's marginal cost.

The proposed revised LMPM methodology, known as the decomposition methodology, will apply mitigation to all resources that have a positive non-competitive congestion component in their locational marginal prices that is attributed to a binding uncompetitive constraint. This process uses the relationship between the generation resource and the binding constraints (the shift factor), the shadow price on binding constraints, and the competitive / uncompetitive designations of binding constraints to decompose the congestion component of each locational marginal price into parts attributable to competitive and uncompetitive binding constraints. If a resource has a positive congestion price component that is attributable to a binding uncompetitive constraint, the resource will be subject to mitigation. Bid prices will be mitigated to the higher of the resource's default energy bid or a calculated competitive baseline price.

By using the impact of a binding uncompetitive transmission constraint on price at the generator location to trigger mitigation, the proposed decomposition methodology limits bid mitigation to only those resources whose locational marginal price is increased as a result of uncompetitive conditions created by congestion. This therefore limits bid mitigation to only those resources that have and potentially could benefit from exercising local market power created by the binding uncompetitive transmission constraint and eliminates the unintended mitigation observed under the current LMPM process. Also, by eliminating these instances of unintended mitigation, the decomposition methodology will reduce the overall frequency of mitigation compared to the current approach.

Methodology for Assessing Impact of Changes

Assessing Path Competitiveness

This assessment of the current and proposed approaches focuses on the accuracy with which each approach in the mitigation run accurately predicted path competitiveness as it was observed in the actual market run (where local market power would be exercised). We calculated the proposed DCPA approach for both the mitigation run and the market run, where the latter is assumed to be the accurate representation of where and when local market power existed. Assessing the accuracy of the static CPA was done by comparing the static CPA path designations for binding constraints in the mitigation run to the DCPA designations for binding constraints in the actual market run. This was repeated using the DCPA in the mitigation run instead of the current static CPA.

The accuracy statistics embody two separate effects. First, congestion in the mitigation run and market run are not always consistent. The ability of any method of detecting local market power prior to the actual market run depends on the accuracy of the mitigation run in reflecting congestion in the actual market run. Inconsistencies in congestion between the two runs will cause either methodology to over or under predict local market power. The second effect is the ability of the CPA method to accurately capture supply conditions relative to the constraint being tested. The fact that both methods are applied in the mitigation run makes them equally susceptible to error resulting from inconsistency in congestion.

The analysis uses the integrated forward market (actual market run) results as the common benchmark for the analysis because of the difference in inputs between the LMPM run and the actual market run and the observed discrepancy in congestion between the day-ahead mitigation run and market run. Currently, the LMPM run clears forecast load against physical supply and exports and excludes virtual bids. The integrated forward market, on the other hand, clears bid-in physical and virtual demand against all bid-in supply and exports – thus, it includes virtual bids. Because the dynamic competitive path assessment will account for virtual bids, it is necessary to use the integrated forward market as the common benchmark for the analysis. Performing the dynamic competitive path assessment for the LMPM run and comparing the resulting path designations to those produced by performing the dynamic competitive path assessment for the integrated forward market would result in an invalid comparison.

There is an additional factor that supports assessing accuracy in the day-ahead market within the IFM (market run) and not between the mitigation run and market run. The ability for the mitigation run to accurately predict congestion in the market run should improve with the addition of bid-in demand, convergence bids, and demand response in the mitigation run. For the study period, the day-ahead mitigation run under-predicted roughly 80 percent of congestion that occurred in the subsequent integrated forward market run on internal lines. This represents an opportunity for under-mitigation as undetected congestion will not trigger mitigation. Further, the mitigation run predicted congestion on internal lines in excess of what was observed by 10 percent. This represents an opportunity for over-mitigation as mitigation may be triggered in the mitigation run in response to congestion that did not actually occur in the market run. Including bid-in demand and all virtual bids, and clearing the market power mitigation run based on bid-in demand, will allow the market power mitigation run to more closely match inputs used in the actual market run.

The assessment of the accuracy when applied in HASP used the DCPA designations from the real-time dispatch (RTD) market run as the benchmark since this is where internal resources would be able to exercise local market power. Designations resulting from the SCPA and DCPA applied in the HASP mitigation run and DCPA applied in the real-time pre-dispatch (RTPD) run were compared to the benchmark designations.

Bid Mitigation

This analysis estimates which resources would be mitigated under the proposed decomposition methodology. Conceptually, within a dispatch interval, any resource that can provide counter-flow to a binding uncompetitive constraint and has a positive congestion component in its locational marginal price is identified as a mitigated resource under the revised LMPM rules. This analysis only identifies the resources that would have been mitigated under the proposed decomposition methodology and does not evaluate the impact on their bid curves. This measure is useful in comparing the frequency and accuracy of resources mitigated under the two methodologies.

An additional adjustment is performed to make the estimate of the number of resources mitigated under the proposed decomposition methodology comparable to the count of effectively mitigated resources observed under the current LMPM approach. As described above, the measure of observed

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mitigated units discounts resources that were not dispatched in the market run for which the mitigation applied or did not have their bid price lowered at the point of market dispatch as a result of mitigation. A large portion of resources identified as being subject to mitigation (because of all constraints run dispatch being greater than competitive constraints run dispatch) are discounted due to no effective impact on their bid curve. About 70 percent of mitigated resources in the day-ahead market and 66 percent of mitigated resources in the real-time market had no effective impact on their bid curves resulting from mitigation.

This analysis does not construct mitigated bid curves for resources expected to be mitigated under the proposed LMPM and hence no determination can be made whether the mitigation would have impacted the resource (*i.e.*, the mitigation lowered the bid price of the resource at the point of market dispatch). The high proportion of observed mitigation that did not effectively impact the bid curve suggests that many resources bid at or below their default energy bids and are not effectively impacted by mitigation. The proportion of zero bid price impact for the day-ahead and real-time markets is applied to the estimated set of resources that would have been mitigated under the proposed approach. This is reasonable given the observed impact of mitigation on bid prices and allows for a more direct comparison to assess changes in mitigation frequency under the two approaches.

By using the impact of a binding uncompetitive transmission constraint on price at the generator location to trigger mitigation, the proposed decomposition methodology limits bid mitigation to only resources whose locational marginal price is increased as a result of uncompetitive conditions created by congestion. This thereby limits bid mitigation to only those resources that have and potentially could benefit from exercising local market power created by the binding uncompetitive transmission constraint and eliminates over-mitigation effects observed with the current LMPM procedures. The determination of whether a resource was over-mitigated in the analysis rests on whether or not that resource had a shift factor to a binding uncompetitive constraint that indicates that the resource could be effective in supplying counter-flow to that constraint. If a resource was mitigated and was not effective on any binding uncompetitive constraint in the hour in which it was mitigated, then that resource was deemed to be over-mitigated.[4]

Impact of Full Implementation in the Day Ahead Market

The following discussion of the analysis will highlight three primary outcomes:

- The dynamic competitive path assessment greatly improves the accuracy of path designations, and reduces the frequency with which paths are designated as uncompetitive.
- Including bid-in demand and convergence bids in the mitigation process will potentially have a dramatic impact on the accuracy of predicting congestion in the mitigation run, and consequently improve the accuracy of local market power mitigation.

[4] One caveat to this measure is the potential that the pre-market mitigation runs, as they iterate to an optimal solution, may have dispatched up and/or committed resources (relative to their output level in the competitive constraints run) and completely resolved congestion on the uncompetitive constraint. In this circumstance, the mitigation would be appropriate despite the fact that the uncompetitive constraint for which the dispatch was made is no longer binding. The way that over-mitigation is measured here would falsely identify this mitigation as over-mitigation. Therefore, the over-mitigation figures presented reflect an upper bound.

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- The net impact of implementing the new mitigation trigger in the day-ahead market improves overall accuracy and reduces the frequency of mitigation by 13 percent. This is largely due to the elimination of unintended mitigation.

Identifying Local Market Power

The analysis reflected in Table 1 below compares the path designations that have occurred with the current static competitive path assessment with those that would have been made using the dynamic competitive path assessment for the day-ahead market. In order to make this comparison, the analysis examined the percentages of competitive and uncompetitive designations under the static competitive path assessment approach and under the dynamic competitive path assessment approach with regard to the common benchmark of all binding eligible constraints in the integrated forward market.

Table 1 shows that using the static competitive path assessment for the day-ahead market results in designation of 53 percent of the paths as competitive and 47 percent of the paths as non-competitive, whereas using the dynamic competitive path assessment for the day-ahead market results in designation of 66 percent of the paths as competitive and 34 percent of the paths as non-competitive. Use of the dynamic competitive path assessment results in a 13 percent increase in designation of paths as competitive (i.e., 66 percent versus 53 percent) and a corresponding 13 percent decrease in designation of paths as non-competitive (i.e., 34 percent versus 47 percent). Because local market power mitigation is triggered only for non-competitive paths, it follows that use of the dynamic competitive path assessment likewise results in a 13 percent decrease in instances where local market power mitigation is triggered.

Table 1 Comparison of Path Designations from Static Competitive Path Assessment and Dynamic Competitive Path Assessment in the Day-Ahead Market

		Dynamic CPA		
		Competitive	Non-competitive	***Total***
Static CPA	Competitive	23%	30%	***53%***
	Non-competitive	43%	4%	***47%***
	Total	***66%***	***34%***	

Table 1 also shows that, almost 75 percent of the time, using the static competitive path assessment for the day-ahead market results in designation of paths that differs from the designation of paths using the dynamic competitive path assessment for the day-ahead market. Specifically, both of those approaches agree as to the competitiveness of 23 percent of paths and the non-competitiveness of 4 percent of paths – a total of 27 percent agreement. Conversely, however, there is disagreement between the approaches as to the competiveness or non-competitiveness of paths a total of 73 percent of the time.[5] Using the dynamic competitive path assessment approach rather than the static competitive path assessment approach makes a dramatic difference in which paths are designated as competitive or non-competitive.

Bid Mitigation

The analysis reflected in Table 2 below evaluates various impacts on local market power mitigation in the day-ahead market and the HASP due to implementation of the CAISO's proposed LMPM enhancements, ignoring for purposes of this analysis the impacts of the CAISO's proposed transition from the static competitive path assessment to the dynamic competitive path assessment. This section will discuss the impact in the day-ahead market. Impacts in the real time-market are discussed in the next section.

The first row in Table 2 shows the percentages of hours in the day-ahead market in which bid mitigation occurs. The second row in Table 2 shows the percentage of hours in the study period in which bid mitigation occurs and there is no binding uncompetitive constraint that could trigger mitigation.

The third row in Table 2 shows the decrease in the percentage of resource-hours during which over-mitigation occurs under the decomposition methodology. The over-mitigation rate in both the day-ahead and real-time market was very high under the current approach. The proposed LMPM approach using the decomposition methodology will eliminate this type of mitigation by mitigating only those resources whose locational marginal price was increased as a result of a binding uncompetitive constraint. Thus, based on the statistics in Table 2, application of the decomposition methodology would have reduced the frequency of mitigation by 94 percent in the day-ahead market.

As described in the CAISO's filing in this proceeding, the proposed LMPM approach will also apply mitigation to a broader set of resources that have local market power as a result of a binding uncompetitive constraint, some of which are not mitigated by the current LMPM process. The fourth row in Table 2 shows the percentage increase in mitigation frequency resulting from applying mitigation to the broader set of resources that have local market power.[6] This effect will increase the frequency of mitigation by 81 percent in the day-ahead market.

The net effect of applying the proposed decomposition methodology for mitigation (with no changes to the path assessment approach) is the sum of the effects of eliminating the over-mitigation and increasing the number of resources accurately mitigated specifically for local market power created by a binding uncompetitive constraint. As shown in the fifth row in Table 2, this net effect reduces the frequency of mitigation by 13 percent in the day-ahead market.

The sixth, seventh, and eighth rows in Table 2 provide some statistics on the set of mitigated resources that were observed under the current LMPM approach during the study period. As shown in the sixth row, the average dispatch differential that triggered mitigation was between 32 MW and 40 MW. The

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[5] *I.e.*, the 30 percent and 43 percent figures shown in Table 1 add up to 73 percent.

[6] The observed frequency of mitigation is used as a baseline for measuring these impacts in terms of percent. For example, if the observed mitigation was 500 unit-hours, then a 94 percent reduction in mitigation (where the new method eliminates unintended mitigation) is a reduction of 470 unit-hours of mitigation. If the new method is also broader-reaching in mitigating units that do have local market power and results in a 81 percent increase in mitigation this is equal to 405 unit-hours of mitigation.

seventh row indicates that the average decrease in bid price at the point of market dispatch resulting from the current mitigation was $3.69/MWh for the day-ahead market and $9.15/MWh for the HASP (including mitigated resources that had a $0 impact on their bid curves). The eighth and final row shows that 70 percent of the mitigated resources in the day-ahead market and 66 percent of the mitigated resources in the HASP had no decrease in their bid prices at the point of market dispatch as a result of bid mitigation.

Table 2 Impact of New LMPM on the Frequency of Mitigation

	Day Ahead	HASP
Percent of hours with bid mitigation	32%	68%
Percent of hours with bid mitigation and no binding uncompetitive constraint	25%	50%
Percent of mitigated resources that were unintended	94%	93%
Percent increase in mitigated resource hours from new LMPM	81%	46%
Net change in resource mitigation hours (eliminate unintended, add increase from new LMPM)	-13%	-48%
Average increase in MPM dispatch that triggered mitigation	40	32
Average decrease in bid price from mitigation (measured at market dispatch)	-$3.69	-$9.15
Percent of resource mitigation hours where there was no effective change in bid price	70%	66%

Impact of Implementing Only the New LMPM in HASP in the Real Time Market

The first phase of implementation will put the new LMP decomposition approach to triggering mitigation in the HASP market, but will not include the DCAP in HASP nor the combined DCPA and LMP decomposition in the subsequent RTUC run just prior to the five minute real time dispatch (RTD) market.

Analysis of the impact on the frequency of mitigation from implementing only the new LMP decomposition in the HASP shows similar results as were found in the day-ahead market. Eliminating the unintended mitigation reduces mitigation frequency (compared to the baseline) by 93 percent, as seen in Table 2. The increase in mitigation frequency resulting from applying mitigation to the broader set of resources that have local market power results in a 46 percent increase. The net result is a 48 percent decrease in the frequency of mitigation. The elimination of the high degree of unintended mitigation indicates a significant improvement in the accuracy of mitigation from applying the new approach.

Impact of Full Implementation in the Real Time Market

Full implementation of the proposed enhancements in the real time market includes the DCPA and LMP decomposition method in both the HASP (primarily to provide mitigation for the short start unit commitment processes) and just after the RTUC (to provide mitigation for the 5-minute dispatch market). This section discussed analysis that support the following:

- Accuracy in the identification of local market power is improved when the DCPA is implemented in the pre-dispatch run after HASP. These gains come from both improved congestion prediction as well as more accurate assessment of the available supply to relieve congestion.
- Improved accuracy and reduced frequency (compared to the current approach) of mitigation that was estimated for HASP is expected to persist during full implementation in the real time market.

Identifying Local Market Power

The purpose of the comparison shown in Table 3, below, is to assess the risk of under-mitigation associated with implementing the dynamic competitive path assessment in the HASP in stage one without application of LMPM in the real-time unit commitment.

In this regard, it is important to note that the outcomes of the LMPM conducted in the HASP often do not closely reflect the outcomes ultimately observed in the five-minute real-time market, which is where the CAISO is most focused on achieving accurate LMPM in the real-time market. Accurate prediction of the congestion that can create local market power is critical to accurate application of LMPM. The HASP market does not accurately predict congestion in the real-time market. Analysis of the data for the study period indicates that the LMPM run in the HASP under-predicted congestion in the real-time market 45 percent of hours where real-time congestion occurred, The HASP LMPM correctly predicted congestion in 21 percent of hours where real-time congestion occurred, and over-predicted congestion in 35 percent of hours reviewed.

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These results suggest the HASP mitigation run outcomes often do not reflect conditions seen in the real-time market. Under-prediction of congestion can lead to instances of under-mitigation, and vice versa for over-prediction of congestion. Both of these cases are the function of mismatch in market outcomes and do not speak directly to the relative accuracy of the static and dynamic competitive path assessments. The instances where the HASP LMPM run correctly predicted congestion in the real-time market are useful for comparing the relative accuracy of the static and dynamic competitive path assessments when used in the HASP alone.

When the HASP mitigation run does accurately predict congestion in the real-time market, application of the dynamic competitive path approach results in significant under-identification of local market power (22 percent accurate) compared with application of the current competitive path assessment approach (89 percent accurate). This result indicates that the dynamic competitive path assessment, when applied in the HASP alone, presents an additional risk of under-mitigation.

This is likely due to the fact that the HASP market is sufficiently removed in time from the real-time market runs and so even when congestion is accurately predicted, the conditions reflected in the HASP and the calculations that produce the path designations do not reflect conditions observed in the real-time market where the mitigation is targeted. The static competitive path assessment uses a default designation non-competitive for non-tested constraints. Although imprecise, this default designation appears to predict uncompetitive conditions in the real-time market better than the dynamic competitive path assessment when applied in the HASP only.

The analysis reflected in Table 3 below compares the difference in accuracy in path designation between implementing a dynamic competitive path assessment in the HASP only and implementing a dynamic competitive path assessment as part of a mitigation run performed every 15 minutes in conjunction with the CAISO's real-time unit commitment process. The purpose of this comparison is to evaluate the gain in accuracy when implementing the LMPM process in the real-time unit commitment in stage two.

In Table 3, the impact on path designation accuracy due to implementing the dynamic competitive path assessment for only the HASP is shown in the row titled "HASP," and the impact on path designation accuracy due to implementing the dynamic competitive path assessment on a 15-minute basis in the real-time unit commitment is shown in the row titled "RTUC." The percentages in both rows were calculated with regard to the common benchmark of path determinations resulting from application of the dynamic competitive path assessment in the real-time market.

The data in Table 3 represent the percentages of dispatch intervals for which the analysis indicates correct and incorrect path designations for competitive and non-competitive paths in any LMPM run with a binding constraint. For example, the analysis indicates that, for 63 percent of the dispatch intervals studied, implementing the dynamic competitive path assessment in the HASP only results in correct designations of competitive paths where there was a binding constraint in either a HASP or a real-time market run. The Table 3 omits dispatch intervals for which there were no binding constraints in either a HASP or a real-time unit commitment run. In those cases, there is no risk of local market power arising and no path designation produced.

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Table 3 Accuracy of Dynamic Competitive Path Assessment in HASP Relative to Real-Time Unit Commitment

Designation Accuracy w/DCPA			Competitiveness As Measured in RTD w/ DCPA		
			Competitive	Uncompetitive	All
	HASP	Correct	63.0%	1.9%	64.9%
		Incorrect	5.8%	28.9%	34.7%
	RTUC	Correct	75.1%	11.0%	86.1%
		Incorrect	5.6%	8.5%	14.1%

Table 3 shows that implementing the dynamic competitive path assessment on a 15-minute basis results in significantly more accurate path designations than implementing the dynamic competitive path assessment in the HASP only. Overall, performing the dynamic competitive path assessment in the real-time unit commitment results in 86.1 percent of path designations being assessed correctly versus 64.9 percent when the dynamic competitive path assessment is run in the HASP only – an improvement of approximately 21 percent. This improvement in accuracy stems from better prediction of real-time market congestion and more current information used in the residual supply index calculations.

It is also important to recognize that limits that establish the floor to which a bid price can be mitigated limit the potential damage from over-mitigating resources. There is no such limit that applies when under-mitigation occurs. Applying the dynamic competitive path assessment approach in the real-time unit commitment run results in a decrease in instances where an uncompetitive path is falsely deemed competitive from 28.9 percent to 8.5 percent, which is a very significant improvement in reducing under-identification of local market power.

Bid Mitigation

The results that were presented for the impact in HASP of the LMP decomposition are expected to reflect the impact under full implementation in the second phase. The HASP will retain the LMP decomposition method in the second phase and an additional mitigation run will be applied in the RTUC just prior to the 5-minute dispatch market. The ISO does not currently apply mitigation after the application in HASP, so there is no empirical or observed mitigation to compare the new approach to for RTUC.

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Attachment E –

Revised Draft Final Proposal – Dynamic Competitive Path Assessment (July 5, 2011)

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

Revised Draft Final Proposal - Dynamic Competitive Path Assessment

Department of Market Monitoring

July 5, 2011

1 Summary of proposal

This paper focuses on the proposed dynamic CPA methodology and implementation specifically. Several refinements to the calculation of the pivotal supplier test and implementation are included in the proposal. The material provided is more detailed in the specification of how the pivotal supplier test will be calculated for the three market applications.

2 Preliminary Items

Phased implementation

The California Independent System Operator Corporation (ISO) has committed to implementing the dynamic competitive path assessment in the day-ahead market and the new local market power mitigation in both the day-ahead and hour-ahead markets in the Spring of 2012. Development of the full real-time application of both the dynamic competitive path assessment and new local market power mitigation in both the hour-ahead and real-time pre-dispatch markets requires additional development and testing, particularly due to computation time and the timing of these markets. The information available in the hour-ahead market for predicting congestion in real-time dispatch as well as system and resource conditions is less accurate than is the information available in the real-time pre-dispatch run. This has implications on the accuracy of mitigation applied in hour-ahead (for real-time dispatch) compared to if it is applied in real-time pre-dispatch.[1] Because of this and the phased implementation, we are proposing to keep the static competitive path assessment in the real-time market until the full dynamic competitive path assessment and local market power mitigation can be implemented in both the hour-ahead and real-time pre-dispatch runs. Using the static (current methodology) competitive path assessment retains the default designation of uncompetitive which we are more comfortable with compared to using dynamic path testing in the hour-ahead scheduling process for mitigation 70+ minutes later in real-time dispatch. Below is the timeline of implementation for new enhancements.

April 2012

- New local market power mitigation in day-ahead and hour-ahead, no local market power mitigation in real-time pre-dispatch.
- Static competitive path assessment used for local market power mitigation in day-ahead and hour-ahead scheduling process.

May 2012

- Dynamic competitive path assessment in day-ahead.
- Continue to use static competitive path assessment in hour-ahead scheduling process.

[1] See prior white paper on the dynamic competitive path assessment "Draft Final Proposal - Dynamic Competitive Path Assessment" at http://www.caiso.com/2b88/2b8871044e720.pdf for graphic of real time market timeline.

Q4 2012

- Dynamic competitive path assessment in the hour-ahead scheduling process.
- Add new local market power mitigation and dynamic competitive path assessment in real-time pre-dispatch.

Timing of execution and constraints tested

The following indicate when the dynamic competitive path assessment will be run when fully implemented.

- Day-ahead: After the all constraints run prior to the day-ahead market.
- Hour-ahead: After the all constraints run prior to the hour-ahead scheduling process.
- Real-time pre-dispatch: After the last real-time pre-dispatch run that procures ancillary services from internal resources just prior to the real-time dispatch runs for the same trade intervals.

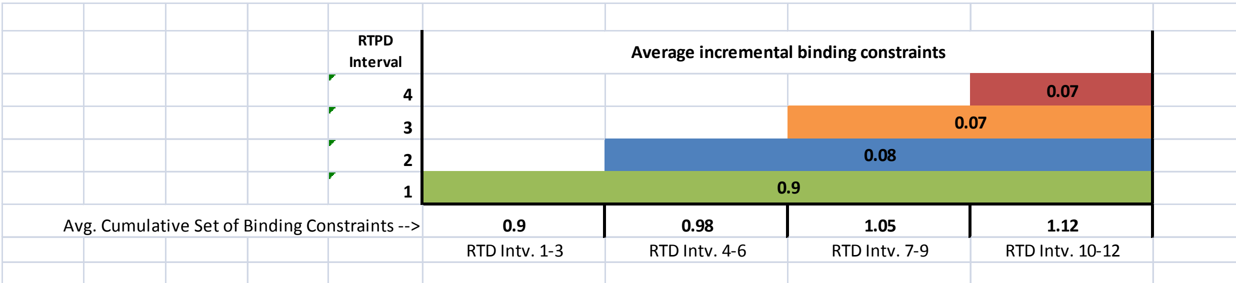
The ISO proposes to test only binding constraints in all three applications of the dynamic competitive path assessment and new local market power mitigation. Table 1 shows statistics for the accuracy of using hour-ahead and real-time pre-dispatch to predict congestion in real-time dispatch. The scoring for the hour-ahead market counts congestion in any interval of the all constraints run in the hour-ahead trade hour against congestion in any interval in the real-time dispatch trade hour. This is the broadest application of prediction using hour-ahead information. The scoring for real-time pre-dispatch takes into account the proposed "balance of hour" mitigation rule for real-time dispatch where a bid will be mitigated for the 15-minute real-time dispatch period corresponding to the first real-time dispatch interval it failed the local market power mitigation test AND for all subsequent real-time dispatch intervals in that trade hour. This is illustrated in Figure 1. There is a substantial gain in accuracy to detecting real-time dispatch congestion in real-time pre-dispatch compared to detecting it in hour-ahead scheduling process.

Table 1 Accuracy of HASP and RTD in predicting congestion in RTD

		HASP		RTPD
Under Identified		4.8%		1.7%
Consistent		23.4%		27.3%
Over Identified		9.5%		8.5%

Figure 1 illustrates how a constraint detected in a real-time pre-dispatch interval matches to the same constraint detected in a real-time pre-dispatch interval. For example, if constraint A is binding for the first time in the second 15-minute real-time pre-dispatch interval (represented on the vertical axis and blue bar) then it will count as a correct match if that same constraint is binding any of real-time dispatch intervals 4 – 12 (represented on the horizontal axis). The numbers in the colored bars show the average number of binding constraints in real-time dispatch and the numbers on the horizontal (real-time dispatch) axis show the cumulative average number of binding constraints in the real-time dispatch. Note that the average is taken on censored data – only hours where there is a binding constraint in real-time dispatch are considered.

Figure 1 Applying the "balance of hour" mitigation approach to scoring the accuracy of predicting congestion in real-time dispatch using real-time pre-dispatch congestion



Accounting for changes in control - tolling agreements

Resources will be assigned to a supplier's portfolio based on the Schedule Coordinator ID associated with that resource unless information has been submitted to indicate that a different market participant has operational or bidding control of the resource through a tolling agreement. In that event, the resource will be assigned to the portfolio of the market participant that contractually has operational or bidding control of the resource.

Market participants will be required to register their tolling agreements with the ISO on a monthly basis. Participants will submit to the ISO in the RDT the resource ID, Schedule Coordinator ID from which the control is being transferred, and the Schedule Coordinator ID to which the control is being transferred. The ISO will verify the submitted information by comparing submissions from both Schedule Coordinators involved in the contract.

Following is the proposed process for obtaining and incorporating information about tolling agreements:

- Parties to a tolling agreement will provide tolling agreement information to the ISO on a monthly basis using a form and/or interface provided by the ISO.
- Data provided will be subject to both the ISO confidential data policy as well as Tariff provisions governing provision of accurate information.
- Submitted data will be validated by matching information submitted by stated counterparties.
- This data will be stored in the ISO Master File and used when calculating the residual supply index through the market software.

Resources and suppliers considered

All resources that are available to the day-ahead market will be considered, whether committed in the all constraints run or not. In other words, we consider the effective available capacity for all resources bid into the day-ahead market regardless of their commitment / dispatch in that hour. Because of the flexibility provided by the multi-period optimization and the potential difference in commitment and dispatch between all constraints run and day-ahead, using the total effective available capacity is appropriate in the day- ahead. In this fashion, ramp constraints are ignored since the multi-period optimization can adjust dispatch in an earlier hour to achieve the dispatch it needs in the current hour if that was economic or necessary.

For the hour-ahead and real-time pre-dispatch applications, available capacity from all online resources can be considered as well as all available short-start resources that are not online at the time of the mitigation run but have sufficiently short start time that they can be online during the binding market / trade interval considered by the competitive path assessment and local market power mitigation.

There are instances where more than one Schedule Coordinator ID is used across generation assets owned or controlled by the same supplier. Accurate assembly of supplier portfolios requires a mapping of generation assets, Schedule Coordinator IDs, and affiliated companies. Market participants who own or control generation assets in the ISO control area will be required to provide this information and update monthly if there are changes.

For determination of the top three potentially pivotal suppliers, only suppliers who are net sellers of electricity at the affiliate level will be considered. Net buyers of electricity do not have an incentive to strategically bid their generation resources to exercise local market power and increase spot wholesale prices. Identification of net buyers to exclude from the set of potentially pivotal suppliers will be determined by the Department of Market Monitoring and will be based on historical market participation.

Treatment of Convergence Bids

Cleared virtual supply bids are included in the demand for counterflow and effective supply calculations for potentially pivotal and fringe competitive suppliers.[2]

The pivotal supplier test used to determine the competitiveness of constraints will be based on market bids for dispatchable physical resources and virtual bids that cleared in the pre-market run on which the assessment is based. Including “in-market” virtual supply bids is appropriate for two reasons. First, the calculation of the demand for counterflow will include virtual supply and demand bids on the system side of the constraint and virtual demand bids on the constrained side. Second, cleared virtual supply bids are revealed to be useful in managing congestion in the (day-ahead) market run and as such should be considered as part of the effective supply and the demand for counterflow. Excluding virtual supply bids on the constrained side that did not clear is necessary to avoid the potential for large quantities of relatively high priced virtual supply bids in the day-ahead market to cause a constraint to be deemed competitive.

[2] Fringe competitive suppliers are the set of (net) suppliers that are not considered potentially pivotal for purposes of applying the pivotal supplier test.

3 Application in the day-ahead market

This section presents the equations and interpretation for identifying the top three potentially pivotal suppliers, calculating the residual supply index, and determining path competitiveness.

The following indices are used in the equations presented below:

i is an index on supply resources,

j is an index on supplier portfolios, and

k is an index on binding transmission constraints.

Pivotal supplier test

The pivotal supplier test for constraint k will evaluate the ability of effective supply to relieve congestion after the removal of effective supply from the three largest potentially pivotal suppliers. The test metric for this residual supply index for binding constraint k is expressed as

RSI_k = (Supply of counterflow to k from potentially pivotal suppliers +

Supply of counterflow to k from fringe competitive suppliers) /

Demand for counterflow on k, or

$= (SCF^{PPS}_k + SCF^{FCS}_k) / DCF_k$,

where SCF^{PPS}_k is the total effective supply of counterflow to binding constraint k from all ***potentially pivotal suppliers*** that is not withheld including physical and cleared virtual supply,

SCF^{FCS}_k is the total effective supply of counterflow to biding constraint k from all ***fringe competitive fringe suppliers*** (those not identified as potentially pivotal suppliers) including physical and cleared virtual supply, and

DCF_k is the total demand for counterflow to binding constraint k.

Equations for SCF^{PPS}_k, SCF^{FCS}_k, $VSCF_k$, and DCF_k are provided later in this section.

The proposed test will evaluate RSI_k for each binding constraint k considering the largest three potentially pivotal suppliers withheld from the supply of counterflow. The method for identifying the three largest potentially pivotal suppliers is provided later in this section.

Constraint k is deemed competitive if $RSI_k >= 1$ and is deemed uncompetitive if $RSI_k < 1$.

Application of Mitigation

Resources that are identified as having local market power in an hour as a result of the dynamic competitive path assessment and local market power decomposition tests are run will have their bids mitigated to the higher of their default energy bid or the competitive LMP as calculated by the LMP decomposition process. Bids will be mitigated for the hour that the resource failed the LMP decomposition test.

Demand for counterflow

The demand for counterflow to binding constraint k is the sum of all dispatched energy that will flow on k in the counterflow direction. The demand for counterflow to binding constraint k is expressed as

$$DCF_k = \Sigma_i -SF_{k,i} * DOP_i$$

for physical resources and virtual supply resources i with $SF_{k,i} < 0$

where DOP_i is the dispatch operating point for physical or virtual supply resource i.

Effective supply of counterflow

It is easiest to view the effective supply of counterflow as comprised of two parts: the highest possible output from the fringe competitive suppliers that do not withhold any capacity and the lowest possible output from the three potentially pivotal suppliers which reflects the capacity they could withhold. In the case of the day-ahead application, the entire output of physical resources belonging to the potentially pivotal suppliers can be withheld. This is not the case in the real-time, and the dynamic competitive path assessment accounts for ramping constraints in the real time application which is discussed later in this paper.

Physical resources

The effective supply of physical counterflow (SPCF) to constraint k from a physical resource i belonging to ***fringe competitive supplier*** (FCS) j is the highest possible output from the fringe competitive suppliers. Fringe competitive suppliers do not withhold any capacity. For the day-ahead market, this is measured as the highest available output that is effective in relieving congestion on constraint k accounting for resource outages and derates. The (location-level) supply of counterflow is expressed as

$$SPCF^{FCS}_{k,j,i} = -SF_{k,i} * ENGYMAX_i$$

for resources i in fringe competitive supplier portfolio j with $SF_{k,j} < 0$

Where $SF_{k,i}$ is the shift factor from location i to constraint j, and

ENGYMAX is the highest output the resource can be dispatched to on energy bids given unit outages and derates and respecting ancillary service awards.[3]

$$ENGYMAX_i = MAXCAP_i – DERATE_i – OR_i – RU_i$$

MAXCAP is the maximum output of the resource or the upper bound of the regulation range if the resource has sold regulation to the ISO,

DERATE is the reduction in potential output from MAXCAP resulting from unit outage or derate,

OR is the operating reserve award (spinning reserve and non-spinning reserve), and

RU is the regulation up award.

The effective supply from resources belonging to fringe competitive suppliers can be summed within supplier j's portfolio to calculate total effective supply from supplier j to constraint k and summed again to calculate total effective supply to constraint k.

The available supply of effective counterflow from fringe competitive supplier j to constraint k is

$$SPCF^{FCS}_{k,j} = \Sigma_i\, SPCF^{FCS}_{k,j,i} \quad \text{for i all in portfolio j.}$$

And similarly, the total available supply of effective counterflow (not withheld) from all fringe competitive suppliers to constraint k is

$$SPCF^{FCS}_{k} = \Sigma_j\, SPCF^{FCS}_{k,j} \quad \text{for all fringe competitive suppliers in j.}$$

The effective supply of counterflow to constraint k from a physical resource i belonging to ***potentially pivotal supplier*** j is zero. Suppliers are not ramp constrained in their withholding from the day-ahead market. As we do not account for ramping constraints in the day-ahead market for the fringe competitive supply of counterflow (above), we also do not account for ramping constraints in the capacity that can be withheld. This is different in the real-time market application which is discussed in a later section. The (location-level) supply of counterflow in the day-ahead market is expressed as

$$SPCF^{PPS}_{k,j,i} = 0$$

for resources i in potentially pivotal supplier portfolio j with $SF_{k,i} < 0$.

Virtual resources

The effective supply of counterflow to constraint k from cleared virtual supply resource i in supplier j's portfolio is expressed as

$$SVCF_{k,j,i} = -SF_{k,i} * DOP_i$$

[3] DMM will further consider whether to adjust available capacity for ancillary service awards made in the all constraints run of the day-ahead market process. While it is important to account for capacity needed to meet ancillary service requirements, the ancillary service procurement made in the day ahead all constraints run may be re-optimized in the actual day-ahead run, freeing up some capacity effective in relieving congestion on an uncompetitive constraint that would have impacted the residual supply index calculation that led to the uncompetitive designation. This refinement will be considered prior to implementation.

for virtual resources i in supplier portfolio j with $SF_{k,i} < 0$.

where DOP_i is the dispatch operating point for virtual supply resource i.

Combined

The combined effective physical and virtual supply of counterflow to constraint k (from the RSI equation above) from physical and cleared virtual supply resources i held by supplier j is

$$SCF_{k,j,i} = SPCF_{k,j,I} + SVCF_{k,j,i}$$

This is aggregated to the supplier portfolio level by summing across physical and cleared virtual resources i, and to the constraint level by summing across portfolios j. This is represented in the residual supply index equation earlier in this section with a superscript distinguishing between potentially pivotal suppliers (PPS) and fringe competitive suppliers (FCS).

Identification of top three potentially pivotal suppliers

Identification of the top three potentially pivotal suppliers in the day-ahead market will be based on the total available effective supply that can be withheld by each supplier. This withheld capacity (WC) from supplier j to binding constraint k is the sum across j's resources, which is expressed as

$$WC_{k,j} = \Sigma_i \; -SF_{k,i} * ENGYMAX_i + \Sigma_i \; SVCF_{k,j,i}$$

for resources i in supplier portfolio j with $SF_{k,i} < 0$.

Other variables are as defined earlier in this section.

For each binding constraint k, suppliers are ranked on WC from highest to lowest and the top three suppliers are identified as the set of potentially pivotal suppliers for that constraint.

4 Application in hour-ahead scheduling process

This section presents the equations and interpretation for identifying the top three potentially pivotal suppliers, calculating the residual supply index, and determining path competitiveness for the application in the hour ahead scheduling process. The formulas and discussion follow what was presented for the day-ahead case closely.

The following indices are used in the equations presented below:

i is an index on supply resources,

j is an index on supplier portfolios, and k is an index on binding transmission constraints.

Pivotal supplier test

The pivotal supplier test for constraint k will evaluate the ability of effective supply to relieve congestion after the removal of effective supply from the three largest potentially pivotal suppliers. The test metric for this residual supply index for binding constraint k is expressed as

$RSI_k = (SCF^{PPS}_k + SCF^{FCS}_k) / DCF_k$,

where SCF^{PPS}_k is the total effective supply of counterflow to binding constraint k from all ***potentially pivotal suppliers*** that is not withheld,

SCF^{FCS}_k is the total effective supply of counterflow to biding constraint k from all ***competitive fringe suppliers*** (those not identified as potentially pivotal suppliers), and

DCF_k is the total demand for counterflow to binding constraint k.

Equations for SCF^{PPS}_k , SCF^{FCS}_k , and DCF_k are provided later in this section.

The proposed test will evaluate RSI_k for each binding constraint k considering the largest three potentially pivotal suppliers withheld from the supply of counterflow. Constraint k is deemed competitive if $RSI_k >= 1$ and is deemed uncompetitive if $RSI_k < 1$.

Application of Mitigation

Resources that are identified as having local market power after the dynamic competitive path assessment and local market power decomposition tests are run in the hour ahead scheduling process will have their bids mitigated to the higher of their default energy bid or the competitive LMP as calculated by the LMP decomposition process. Bids will be mitigated if the resource fails this test in any of the four hour-ahead all constraints run 15-minute trade intervals. Mitigated bids will be used in the hour-ahead market run and all subsequent short-run unit commitment and real-time ancillary service runs prior to the 5-minute real-time dispatch market. Path competitiveness and the LMP decomposition test will be re-applied in the last real-time pre-dispatch run. At that time, mitigation will be applied to the set of unmitigated bids that were submitted prior to the hour-ahead scheduling process.

Demand for counterflow

The demand for counterflow to binding constraint k is the sum of all dispatched energy that will flow on k in the counterflow direction. The demand for counterflow to binding constraint k is expressed as

$DCF_k = \Sigma_i -SF_{k,i} * DOP_i$

for resources i with $SF_{k,i} < 0$

where DOP_i is the dispatch operating point for resource i.

Effective supply of counterflow

It is easiest to view the effective supply of counterflow as comprised of two parts: the highest possible output from the fringe competitive suppliers that do not withhold any capacity and the lowest possible output from the three potentially pivotal suppliers which reflects the capacity they could withhold.

Physical resources

The effective supply of physical counterflow (SPCF) to constraint k from a physical resource i belonging to ***fringe competitive supplier*** (FCS) j is the highest possible output from the fringe competitive suppliers. Fringe competitive suppliers do not withhold any capacity. This is measured from the last dispatch operating point taking into account the ramp rate of the resource and any limitations on the available capacity. The (location-level) supply of counterflow is expressed as

$$SPCF^{FCS}_{k,j,i} = -SF_{k,i} * \min (LDOP_i * (1 + RR_i * 15) , ENGYMAX_i)$$

for resources i in fringe competitive supplier portfolio j with $SF_{k,j} < 0$

Where $SF_{k,i}$ is the shift factor from location i to constraint j,

$LDOP_i$ is resource i's dispatch operating point from the prior interval,

RR_i is resource i's ramp rate in MW/minute, and

ENGYMAX is the highest output the resource can be dispatched to on energy bids (not accounting for ramp rate) given unit outages and derates and respecting ancillary service awards.

$$ENGYMAX_i = MAXCAP_i – DERATE_i – OR_i – RU_i$$

MAXCAP is the maximum output of the resource or the upper bound of the regulation range if the resource has sold regulation to the ISO,

DERATE is the reduction in potential output from MAXCAP resulting from unit outage or derate,

OR is the operating reserve award (spinning reserve and non-spinning reserve), and

RU is the regulation up award.

The effective supply from resources belonging to fringe competitive suppliers can be added to get total effective capacity from supplier j to constraint k. This is done for potentially pivotal suppliers below, and the same additive property applies to $SPCF^{FCS}_{k,j,i}$.

The effective supply of counterflow to constraint k from a physical resource i belonging to ***potentially pivotal supplier*** j is the lowest output this supplier can achieve given the dispatch operating point, resource ramp rates, and minimum output limits. This calculation reflects that a supplier is constrained in how much capacity it can withhold by the physical ability of its resources to ramp down (and consequently withhold). The (location-level) supply of counterflow is expressed as

$SPCF^{PPS}_{k,j,i} = -SF_{k,i} * \max (LDOP_i * (1 - RR_i * 15) , ENGYMIN_i)$

for resources i in potentially pivotal supplier portfolio j with $SF_{k,i} < 0$

Where ENGYMIN is the lowest output the resource can be dispatched to on energy bids (not accounting for ramp rate) given unit outages and derates and respecting ancillary service awards.

$ENGYMIN = MINCAP + RD,$

MINCAP is the minimum load output or the lower regulation range if awarded regulation down,

RD is the regulation down award, and

All other variables are as defined for $SCF^{FCS}_{k,j,i}$

These location-level supply calculations are additive to the portfolio and constraint level. The remaining available supply of effective counterflow (not withheld) from potentially pivotal supplier portfolio j to constraint k is

$SPCF^{PPS}_{k,j} = \Sigma_i SPCF^{PPS}_{k,j,i}$ for i all in portfolio j.

And similarly, the total available supply of effective counterflow (not withheld) from all potentially pivotal suppliers to constraint k is

$SPCF^{PPS}_{k} = \Sigma_j SPCF^{PPS}_{k,j}$ for all potentially pivotal suppliers in j.

Virtual resources

Convergence bids liquidate in the real time market. Therefore there are no virtual resources to consider in the dynamic competitive path assessment executed in hour-ahead (or real-time pre-dispatch).

Identification of top three potentially pivotal suppliers

Identification of the top three potentially pivotal suppliers will be based on the most ramp-constrained capacity a supplier can withhold.[4] We measure this capacity as the distance between the highest and lowest output levels a resource can ramp to in the test period based on their dispatch point in the prior period. This withheld capacity (WC) from supplier j to binding constraint k is the sum across j's resources, which is expressed as

$$WC_{k,j} = \Sigma_i \; -SF_{k,i} * [\min (LDOP_i * (1 + RR_i * 15) , ENGYMAX_i) - \max (LDOP_i * (1 - RR_i * 15) , ENGYMIN_i)$$

[4] We note that this measure of potential withheld capacity does not directly account for a resource fully withholding by shutting down. We recognize that this potential exists but note that some of the withheld capacity will be accounted for in the proposed measure and the market will detect after a few intervals that the resource is now off-line and that absence of capacity will be reflected in the measure. In addition, the Department of Market Monitoring monitors for physical withholding.

for resources i in supplier portfolio j with $SF_{k,i} < 0$.

Other variables are as defined earlier in this section.

For each binding constraint k, suppliers are ranked on WC from highest to lowest and the top three suppliers are identified as the set of potentially pivotal suppliers for that constraint.

5 Application in RTPD

Application of the three pivotal supplier test is the same in real-time pre-dispatch as described for hour-ahead scheduling process with the following changes.

Frequency and Inputs

The pivotal supplier test will be run every 15 minutes in the last applicable real-time pre-dispatch run prior to the corresponding real-time dispatch intervals. The competitive path assessment calculations will use the market outcomes from this real-time pre-dispatch run.

Mitigation of bids

For resources identified as having market power via the LMP decomposition test, bids will be mitigated for the balance of the trade hour beginning the first 5-minute real-time dispatch interval corresponding to the 15-minute real-time pre-dispatch interval where the resource first failed the LMP decomposition test.

6 Process

This material will be presented at the July 6, 2011, stakeholder call on the local market power mitigation enhancements market initiative. The dynamic competitive path assessment and new local market power mitigation will be presented to the ISO Board of Governors at the July 13-14 meeting as a decisional item.

Formal comments on this version of the proposal will not be compiled and presented in a separate document. However, please feel free to contact Jeff McDonald in the Department of Market Monitoring with questions or comments at JMcDonald@caiso.com or (916) 608-7236.

Attachment F –

Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 –

Revised Draft Final Proposal (Oct. 30, 2012)

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2

Revised Draft Final Proposal

October 30, 2012

Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2

Revised Draft Final Proposal

Table of Contents

1 Introduction

Implementation of the second phase of the LMPM Enhancements market initiative will introduce a dynamic assessment of local market power and end the static approach that has historically been utilized to determine non-competitive constraints. While the new dynamic assessment will greatly improve the accuracy of local market power mitigation within the market dispatch, it does introduce a gap for determining non-competitive constraints in connection with Exceptional Dispatches. This proposal addresses that gap by creating a separate set of path designations that are based on the dynamic designations and will be used to dertermine when an Exceptional Dispatch should be mitigated. The proposal also extends the methodology to providing a set of default path designations that will be used as “back-up” in the event that the dynamic competitive path assessment within the market software fails to produce a valid set of path designations.

The paper is organized as follows. The issue of Exceptional Dispatch mitigation and path competitive/non- competitive designation is described, and then stakeholder comments are listed. A few general alternative methods are discussed, and in particular, statistical tests are demonstrated. Finally the proposal is given, which remains the same as the previous one, followed by the impact studies.

2 Process and Time Table

Item	Date
Post Issue Paper and Straw Proposal	July 20, 2012
Stakeholder Conference Call	July 27, 2012
Stakeholder Comments Due	August 3, 2012
Post Draft Final Proposal	September 7, 2012
Stakeholder Conference Call	September 11, 2012
Stakeholder Comments Due	September 18, 2012
Post Revised Draft Final Proposal	October 30, 2012
Stakeholder Conference Call	November 6, 2012
Stakeholder Comments Due	November 14, 2012
Board Meeting	December 13-14, 2012

3 Exceptional Dispatch Mitigation Issue under Dynamic Competitive Path Assessment

Under existing rules, Exceptional Dispatch are subject to mitigation under four circumstances where the Exceptional Dispatch was made to

1. Address reliability requirements related to non-competitive transmission constraints,
2. Access stranded Ancillary Services Awards or RUC Availability, and

3. To manage specific resources whose water source comes from the Sacramento Delta ("delta dispatch").
4. Move a resource to its minimum dispatchable operating level to make available the higher ramp rates for that resource.

When an exceptional dispatch is made for any of these four reasons, the price applied to the calculated Exceptional Dispatch Energy (EDE) is mitigated to the better of the resource's Default Energy Bid or the Locational Marginal Price (LMP).[1]

The existing approach is as follows. Cases where the Exceptional Dispatch was made to manage a non-competitive transmission constraint are identified by associating the transmission constraint indicated by the ISO dispatcher in the Exceptional Dispatch log with the corresponding constraint on the list of competitive constraints that is produced four times each year by the Department of Market Monitoring using the static competitive path assessment methodology.

As described above, the existing approach for determining when to apply mitigation to Exceptional Dispatch that were made to manage a non-competitive constraint relies on the existence of a list of competitive constraints. If a constraint is not on the list of competitive constraints, it is non-competitive. Currently a static list exists that is the outcome of a competitive path assessment performed four times each year by the Department of Market Monitoring. When LMPM Enhancements Phase 2 is implemented in the Spring of 2013 the real time market will have a dynamic competitive path assessment performed in-line with the execution of the market software and the static list will no longer be produced. This creates a gap in identifying circumstances where Exceptional Dispatches are made to manage non-competitive constraints and appropriately applying local market power mitigation.

Most Exceptional Dispatch are preemptive – made in anticipation of certain circumstances based on observed system and market conditions that cannot be managed by the market software as opposed to reacting to an event or circumstance that has already happened. Preemptive Exceptional Dispatch made to manage transmission constraints may have the effect of relieving the anticipated congestion such that it does not materialize in the market. In this case, since the congestion was preempted by the Exceptional Dispatch there will be no dynamic competitive path assessment performed for that constraint. This introduces a potentially material under-identification of local market power since the Exceptional Dispatch was made under circumstances that presumed congestion and was limited by the set of resources that were effective in relieving the presumed congestion. These circumstances may have been non-competitive and created local market power that could not be detected by the dynamic competitive path assessment since the Exceptional Dispatch relieved the congestion in the market and precluded assessment and application of mitigation.

A separate set of path designations is required to determine whether an Exceptional Dispatch is for the purpose of managing non-competitive constraints. This is only an issue with Exceptional Dispatches issued to manage transmission constraints in real time.

The dynamic competitive path assessment that identifies local market power within the execution of the market software presumes a constraint is competitive unless it fails the competitiveness test. In this case, the presumption of competitive unless proven otherwise is predicated on the availability of a positive test for competitiveness. In the case described above where the Exceptional Dispatch relieved the congestion that would have prompted the test, there is no positive test to rely on to identify non-competitive circumstances. The default of

[1] If the clean bid is less than the default bid, the settlement is the greater of the clean bid or the LMP.

competitive is not valid unless there is a positive test to determine otherwise. The proposed methodology accounts for this gap.

4 Stakeholder Comments and Feedback

There are two stakeholder calls to discuss this market initiative in July and September. A few typical comments are related to:

- The existence and mitigation of exceptional dispatch itself
- Alternative method to deem competitiveness for Exceptional Dispatch related transmission facilities
- The reason for thresholds (10 hours and 75%) in the proposed test

The current market initiative tries to address the problem of Exceptional Dispatch mitigation when dynamic competitive path assessment is implemented in real-time market. The general circumstance or assumption is that the exceptional dispatch may still exist, and some of them will be mitigated, as described in ISO tariff. Although some stakeholders expressed opinions on the use of exceptional dispatch itself, this is not really the subject of this market initiative. The purpose of this market initiative is to address the lack of competitive designation for the exceptional dispatch mitigation, and the proposal is consistent with the current existing practice. Although the focus of this market initiative is not to address the general Exceptional Dispatch topic, it does provide some information on the different categories of Exceptional Dispatch and the corresponding mitigation impact.

The alternative methods to deem competitiveness and justification for the fixed threshold are directly related to this market initiative. Below there are two sections addressing them, one discussing alternative methods and their difficulties, the other using statistical test to support the thresholds.

5 Discussion of Alternative Solutions

The center topic of the market initiative is how to designate transmission competitiveness for exceptional dispatch, given that the market may not be able to give the designation in the dynamic competitive path assessment. There are a few general options:

- Designation from off-line study
- Default static designation (either competitive or non-competitive by default)
- Designation from historical data

Designation from off-line study

One alternative suggested by stakeholders is to perform and off-line study of each specific reason an exceptional dispatch is made in real time. This could be performed periodically once a specific reason was used frequently or each time an exceptional dispatch was made for a transmission related reason. In order to perform an off-line study of the competitiveness of transmission related Exceptional Dispatch reasons, the ISO would need to be able to accurately quantify both available effective supply, demand for the product that the Exceptional Dispatch is producing, where the later may require re-simulation to create congested conditions that were anticipated when the Exceptional Dispatch was issued. A clear statement or quantification of demand is not always available, and because there is an element of Operator discretion in determining the need for and issuing Exceptional Dispatch, there are many cases where the perceived demand is not obtainable after the fact. Furthermore, even in instances where the supply and demand are well defined and quantifiable, performing a competitiveness test requires extensive effort. This has been the case with the "static" competitive path assessment, and performing more tests on less well defined constraints / products is not practical on an ad hoc basis.

Default static designation (either competitive or non-competitive by default)

The second option is to deem Exceptional Dispatch related transmission facilities either always competitive or always non-competitive with no little or no reevaluation. This is a very crude designation, and is less consistent with the more dynamic approach originally proposed in this initiative. Blanket static designations (all are always uncompetitive / competitive) not only fail to recognize changes in market and market model conditions, but also can be overly mitigative (in the case of always non-competitive) or inappropriately allow for the exercise of local market power (in the case of always competitive).

Designation from historical data

The third option, which is relied on by the current proposal, is to derive competitiveness/non-competitiveness designation based on historical data. Although market and operating conditions may not be exactly the same at two different times, there may be intrinsic information shared by a few recent cases. For example, spring operating conditions may be different from other seasons. If a constraint tends to be binding in spring, competitiveness evaluation from recent days may still be valid, since it reflects the general spring operating conditions. Other advantages of historical data designation are that it is systematic and relatively simple. Therefore, the proposal adopts it as the basis for the Exceptional Dispatch transmission designation.

6 Applying a Statistical Test for Competitiveness

Stakeholders provided comments indicating the ISO did not provide adequate support for the proposed rules for establishing whether an Exceptional Dispatch was made under competitive conditions. One of the several aspects encompassed by these comments is the use of two thresholds for competitive classification: (1) at least 10 hours of observed congestion in the prior 60 days, and (2) observed historical competitive rate over the prior 60 days is greater than 75 percent. As discussed elsewhere in this paper, the approach and threshold values were chosen to be consistent with the target of this design element: to provide a designation where we are reasonably confident that the transmission constraint is predominantly competitive.

To apply a statistical hypothesis test to this problem, we set up a null hypothesis (Ho) and an alternate hypothesis (Ha) to which we apply the statistical test:

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Ho: $x \le x^*$ (observed competitive hours x is not greater than the threshold value x*)

Ha: $x > x^*$ (observed competitive hours x is greater than the threshold value x*)

The test will either fail to reject the null hypothesis, in which case we accept that the constraint is not competitive, or reject the null hypothesis and accept the alternate hypothesis that the observed historical competitive rate exceeds the threshold and the constraint is deemed competitive.

Specification of the statistical test requires knowing the distribution and related parameters of the test variable, a threshold value, and a confidence level at which the test is evaluated. The test variable is the series of observed historical competitive designations which are binary (competitive, non-competitive) and follow a binomial distribution with sample size n, observed number of successes (competitive designations) x, and observed success rate or probability of success equal to x / n.

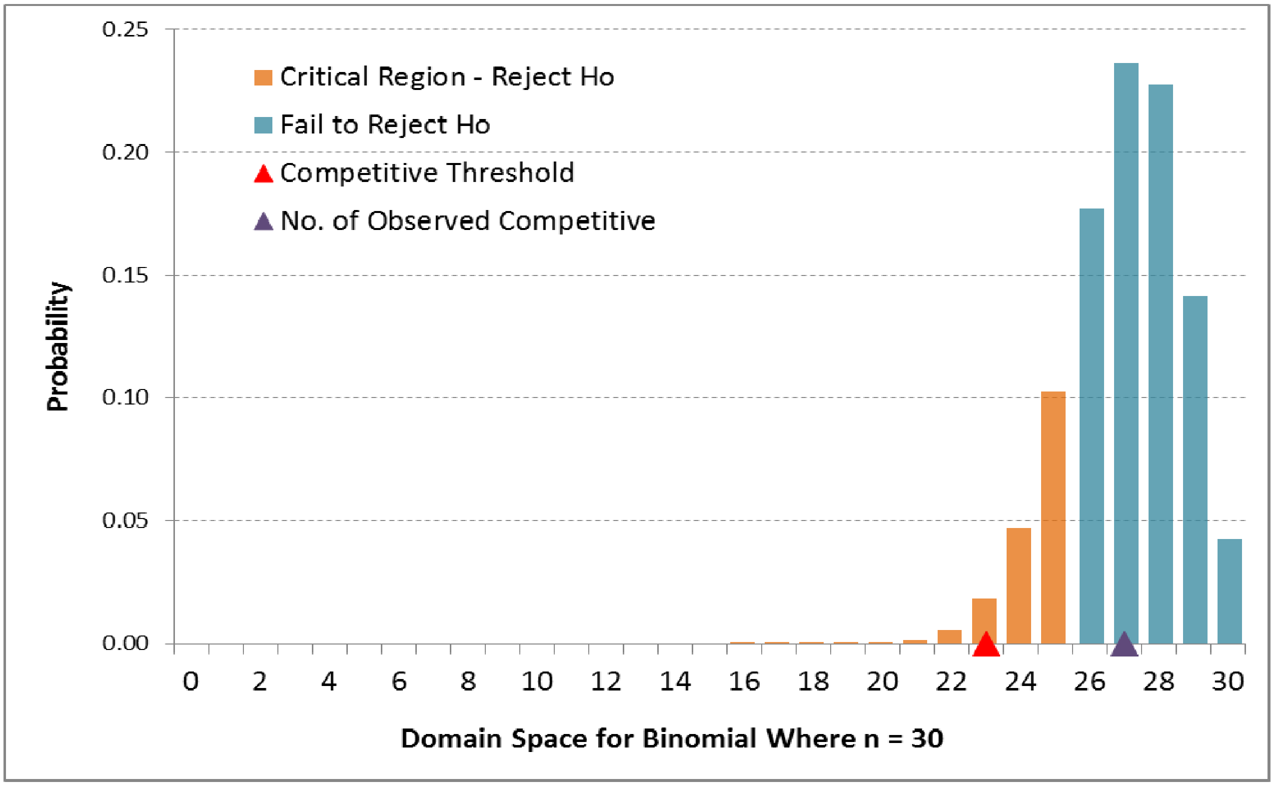
The threshold value x* represents the number of successes that defines "predominantly competitive". Instead of explicitly stating x*, we express the test threshold as a proportion p* and apply the sample size n to derive the threshold number of success x*. We have chosen 75 percent, or p* = 0.75, as the threshold that identifies predominantly competitive. For a sample where n = 30, the resulting x* is 23 (p* x n = 0.75 x 30 = 22.5 and round up to next whole number).

The confidence level at which we apply the test, cl, is 0.75. The confidence level takes into account the variance of the distribution of the observed historical competitiveness. Used in this statistical test, the confidence level defines the minimum amount of the distribution that must lie above the test threshold x* in order for us to reject the null hypothesis that the constraint is non-competitive and accept the alternate hypothesis that the constraint is competitive. The value 0.75 is chosen to correspond to the "reasonably confident" portion of the statement about determining that a constraint for which an Exceptional Dispatch is made is competitive. Higher degrees of confidence (generally from 0.90 to 0.99) are most often applied in statistical hypothesis testing. A higher confidence level in this test reduces the likelihood that the historical data will conclude the constraint is competitive. We have used a lower confidence level here in recognition of the conservative three pivotal supplier test that underlies the historical data on which this statistical test is based.

Figure 1 shows an example of this statistical test for the parameters described above. The binomial distribution is depicted with the bars for sample size of 30 hours, 27 of which were competitive (by way of the Dynamic Competitive Path Assessment). The purple triangle indicates the observed number of competitive hours (27), and the red triangle indicates the threshold number of observed competitive hours (23). The distribution is segmented by color to indicate the confidence level of 0.75. The blue bars indicate the upper 75 percent of the distribution and the orange bars indicate the lower 25 percent of the distribution.

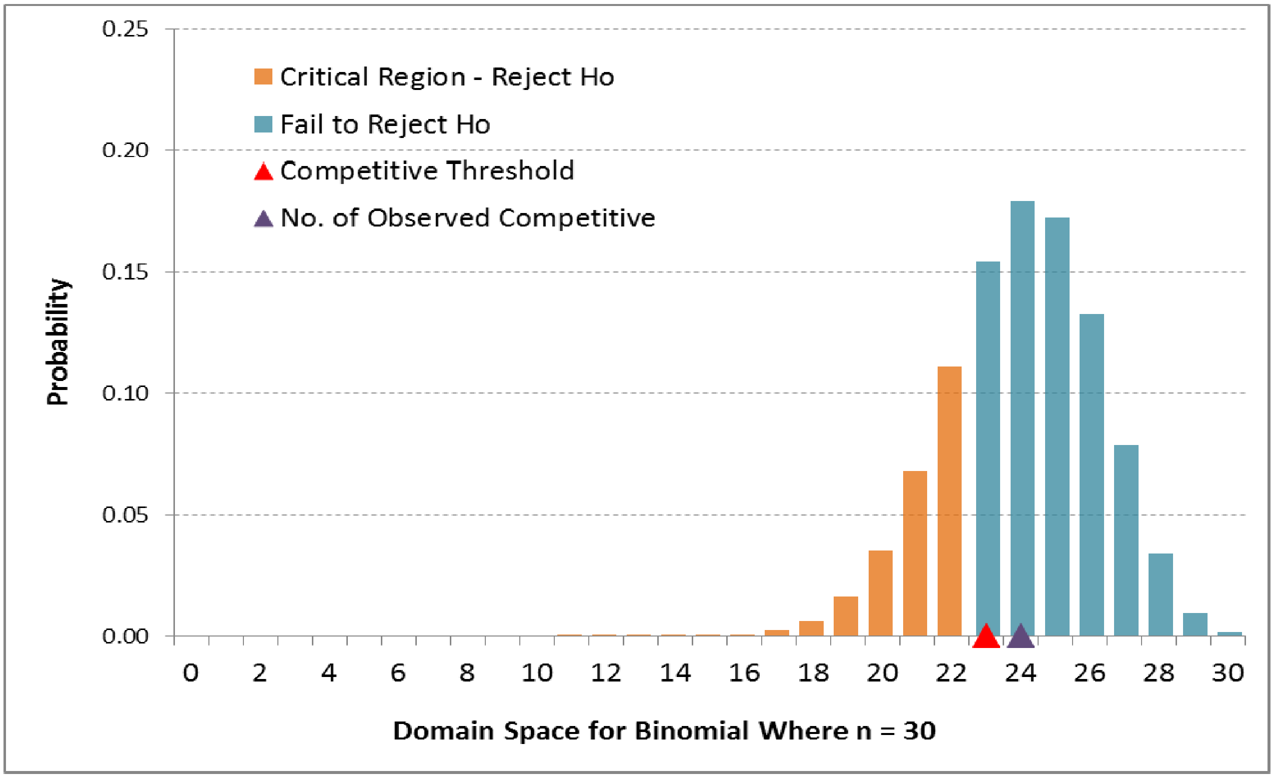
In this case, the test threshold is in the "critical region" (lower 25 percent of the distribution) which means that more than 75 percent of the distribution (our confidence level) lies above the test threshold. We reject the null hypothesis that the constraint is non-competitive and accept the alternate hypothesis that the constraint is competitive.

Figure 1: Distribution and hypothesis test for case where 27 of 30 observed hours of congestion were competitive



A different scenario is depicted in Figure 2, which shows the same test conditions except the observed number of competitive hours is 24 (or 80 percent). Note that the observed number of competitive hours is (slightly) greater than the test threshold number of hours (purple triangle is to the right of the red triangle). However, the test threshold is not in the "critical region", so less than 75 percent of the distribution lies above the test threshold. Therefore, we cannot conclude with a confidence level of 0.75 that the number of observed competitive hours indicates the constraint is competitive (i.e. we cannot reject the null hypothesis that the constraint is non-competitive).

Figure 2: Distribution and hypothesis test for case where 24 of 30 observed hours of congestion were competitive



We can use this hypothesis test for different sample sizes (number of hours of observed congestion) to derive a competitive frontier. This frontier will describe the minimum number of observed competitive hours required to conclude with 75 percent confidence that the constraint is predominantly competitive for any sample size. The resulting competitive frontier has two important properties. First, the proportion of observed competitive hours is significantly above 75 percent with small sample size and decreases to converge with 75 percent as the sample size increases. Second, the test is less accurate and reliable for very small sample size.

The competitive threshold derived from applying this hypothesis test to different observed hours of congestion (sample size) is consistent with the original proposal where a minimum number of congested hours and minimum observed competitive rate among those hours is required to be reasonably confident that the constraint for which the Exceptional Dispatch was made was predominantly competitive. The original proposal is, therefore, a simplified application of the competitive designation rules prescribed by the more formal statistical hypothesis test described in this section. For this reason, the current proposal recognizes this relationship and maintains the original simple representation of the thresholds for competitive designation for mitigation of Exceptional Dispatch, which are described again in more detail below.

7 Proposal for Triggering Mitigation of Exceptional Dispatch for Non-competitive Constraints

The ISO proposes to use historical designations produced by the dynamic competitive path assessment that is executed in the RTUC market runs to create a set of path designations that are used in applying mitigation to Exceptional Dispatch. The proposed methodology applies a threshold to both the frequency of observed congestion as well as the frequency with which the constraint is deemed competitive by the dynamic competitive path assessment. As discussed above, the underlying premise that supports a competitive default designation does not hold in the cases where the path has not been sufficiently tested. In cases where there is insufficient testing (the frequency with which the path has been binding and tested does not meet the threshold) the path will be deemed non-competitive for purposes of applying mitigation to Exceptional Dispatch.

The proposed methodology for determining path designations for purposes of applying mitigation to Exceptional Dispatch is

- A constraint that passes the following two thresholds will be deemed competitive for purposes of applying mitigation to Exceptional Dispatch:
  - Congestion Threshold: Congested in 10 hours or more in the RTUC run where the dynamic competitive path assessment is calculated, and
  - Competitive Threshold: Deemed competitive 75 percent or more of the instances where the constraint was binding and tested.
- Data for the test statistics will reflect the most recent 60 days of trade dates available at the time of testing to focus application on more seasonal conditions.
- This set of designations will be updated not less frequently than every seven days to reflect changes in system and market conditions.

The purpose of the Congestion Threshold is to ensure there are sufficient instances where the constraint has been tested in the past 60 days such that the Competitive Threshold is a more robust statistic. The purpose of the Competitive Threshold is to strike a balance between the two non-observable conditions at the time of the Exceptional Dispatch. The proposed 75 percent threshold is intended to provide allowance for some historical observations of non-competitive conditions but still ensure that the constraint has been predominantly competitive before excusing associated Exceptional Dispatch from the application of local market power mitigation.

As described above, since there may be no positive test of competitiveness in a particular interval we substitute a statistic based on historical tests (via the dynamic assessment) as a proxy for determining whether or not the constraint for which the Exceptional Dispatch was made was competitive or non-competitive at the time the dispatch was made.

An exception to the above criteria will apply to Path 15 and Path 26. These two paths will be considered competitive unless the constraint was congested in 10 or more hours in the test period and was deemed competitive less than 75 percent of the time. This exception allows these major inter-zonal interfaces to remain competitive even when they have not been binding in the past 60 days. If they have been binding 10 or more hours and test competitive less than 75 percent of the time then the designation used for applying mitigation to Exceptional Dispatch will be non-competitive.

8 Default Designations for Use if LMPM Process Fails

There is an additional process that requires path designations in the event they are not available from the market. Competitive path designations are required in the event of a failure of the dynamic competitive path assessment in the market software. In this instance, the next step in the mitigation process, the mitigation trigger (LMP Decomposition), may still be able to run if provided a set of path designations that can be used in the decomposition of the LMP and evaluation of need for mitigation. Further, if the entire mitigation process is unable to run the price evaluation and correction process will need a set of path designations to use in evaluating whether or not the absence of mitigation had a material impact on price.

The path designations that result from the proposed approach in Section 7 can be used as the default set of path designations effective in the event the dynamic competitive path assessment does not complete successfully in the market software. The set of default path designations based on historical data from the real time market (used for mitigation of Exceptional Dispatch) will serve as the default designations for the HASP and RTUC runs of the mitigation process. The ISO will use the same methodology applied to historical data from the day ahead market to produce a set of default designations to be applied in the event of a failure of the dynamic competitive path assessment in the day ahead market.

9 Impact of the Proposal

Exceptional Dispatch Categories

The market initiative addresses the transmission related exceptional dispatch mitigation. Historical data is compiled to show the categories of Exceptional Dispatch. The historical analysis is based on data from the 12-month period August 1, 2011, to July 31, 2012. The data source is the exceptional dispatch logs, which includes both formatted and unformatted information. The analysis considers only exceptional dispatch with a “minimum go-to” and thus would most likely be subject to mitigation. All records are categorized as “System Competitive”, “TModel Competitive”, “TModel NonCompetitive”, “NonTModel”. For the category of “NonTModel”, it is further categorized by whether the Exceptional Dispatch is at dispatchable minimum generation, at minimum generation, or other (meaning either it is either not at dispatch minimum generation or minimum generation, or such information is not available).

The combined TModel cases (TModel Competitive and TModel NonCompetitive) accounts for 40% of the Exceptional Dispatch, which is subject to the current proposal rule. There is another NonTModel Other category, accounting for 14% of the Exceptional Dispatch, and part of it is subject to the current proposal rule too, if it is transmission related.

Figure 3: Relative frequency of Exceptional Dispatch by Category (Percentage)

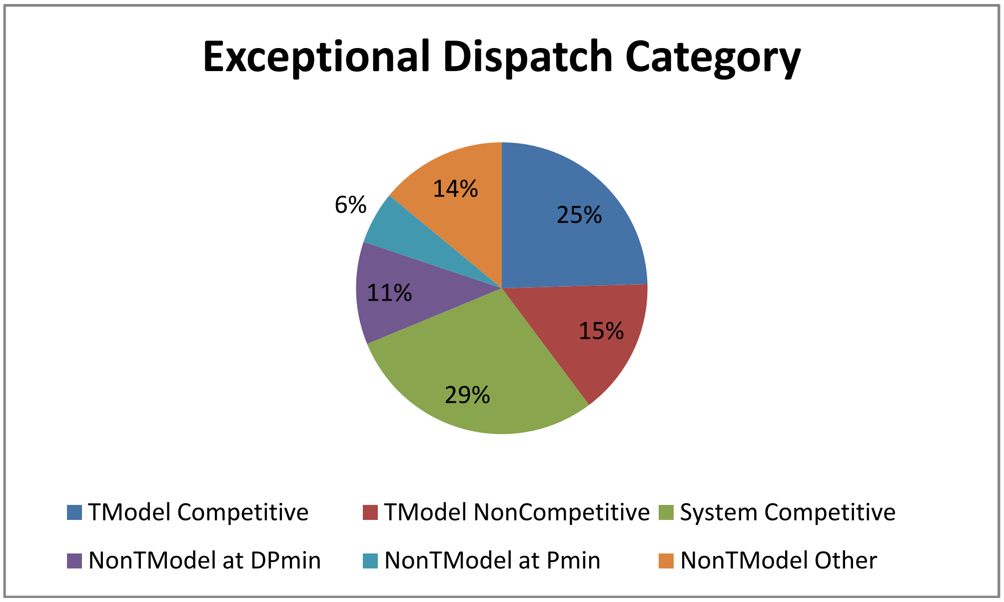
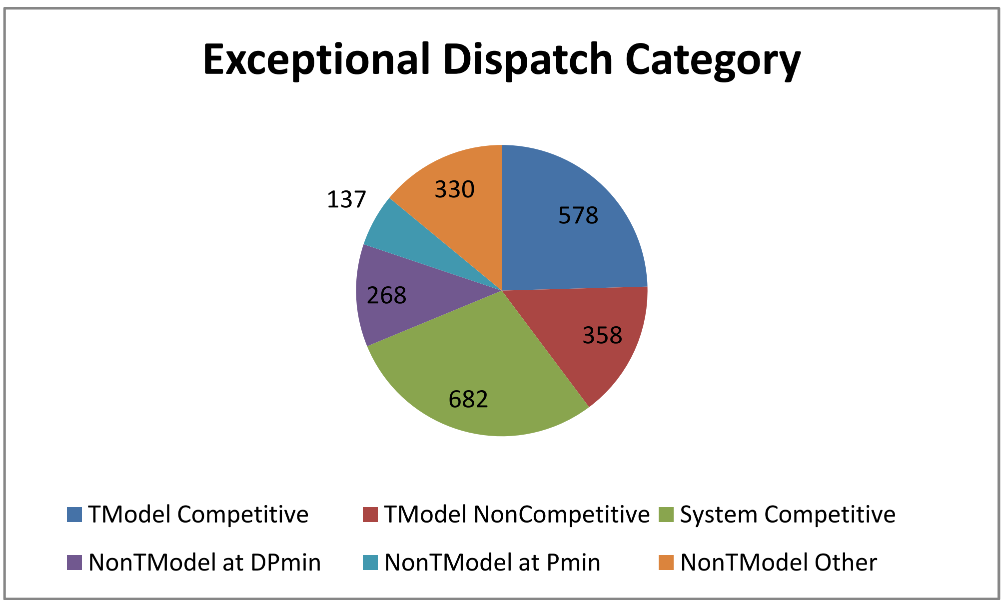


Figure 4: Absolute frequency of Exceptional Dispatch by Category (Number)



10 Next Steps

The ISO will discuss this revised draft final proposal with stakeholders during a conference call to be held on November 6, 2012. The ISO requests comments from stakeholders on the proposed market design described in this straw proposal. Stakeholders should submit written comments by November 14, 2012 to EDMitigation@caiso.com.

Attachment G –

Market Surveillance Committee Opinion on Mitigation Measures for

Exceptional Dispatch in Real-Time (Dec. 5, 2012)

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

Opinion on
Mitigation Measures for Exceptional Dispatch in Real-Time

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair
Shmuel S. Oren, Member

Members of the Market Surveillance Committee of the California ISO

Final of December 5, 2012

1. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the ISO's proposals for mitigation measures to be applied to exceptional dispatch (ExD) in real-time.[1] Mitigation of ExD has been the subject of several MSC meetings over the past few years, and an earlier version of the latest proposal were discussed at the Oct. 19, 2012 MSC meeting in Folsom. In addition, MSC members have participated in stakeholder calls and have reviewed stakeholder comments submitted to the ISO. The MSC has also issued an opinion on general principles for exceptional dispatch mitigation on May 7, 2008.[2]

In summary, we support the ExD proposal as a bare minimum mitigation measure made necessary by changes to the process of designating transmission constraints as competitive or uncompetitive. So-called "static" analyses of a constraint's competitiveness will no longer be performed as part of the local market-power mitigation process, and therefore cannot be used to determine whether the offers of a resource that is exceptionally dispatched should be subjected to mitigation. We also support the proposed mitigation rules that apply when the dynamic competitive path analysis fails to run.

We are concerned with the continuing high levels of exceptional dispatch, and particularly the relative lack of information concerning their causes and effects. We are concerned that exceptional dispatch may unnecessarily raise costs to consumers because of nontransparent and possibly inefficient dispatch that do not appropriately consider alternative ways to meet non-modeled constraints. We are also concerned that generators who are exceptionally dispatched for competitive constraints (and therefore are not mitigated) may be consistently selected in a manner

[1] California ISO, *Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2, Revised Draft Final Proposal*, Oct. 30, 2012, www.caiso.com/Documents/RevisedDraftFinalProposal-ExceptionalDispatchMitigationRealTime.pdf

[2] F. Wolak, J. Bushnell, and B.F. Hobbs, *Opinion on Exceptional Dispatch: Options for Market Power Mitigation and Supplemental Pricing under MRTU*, Market Surveillance Committee of the California ISO, May 7, 2008, www.caiso.com/1fc7/1fc7d6221ea52.pdf

that enables them to raise their bids, thereby potentially increasing the amount of bid cost recovery they would be eligible for, even though other resources could also be used to resolve the constraint. Whether this occurs under the new system requires careful monitoring.

Finally, we recommend that in cases in which a real-time exceptional dispatch call applies to multiple periods, generating units should not be allowed to change its bid from its level before the first exceptional dispatch call.

The opinion is organized as follows. In the next section, we briefly summarize our previous opinion on ExD and the present CAISO proposal. In Section 3, we offer some general comments on the proposal and on the economic effects of ExD, including effects on prices. Then in Section 4, we express three concerns about the ability of the proposed mechanism to identify and mitigate market power that generators could exercise in response to ExD. These include the backwards nature of the test, which might not reflect current market conditions; the possibility that the process by which generators are selected for ExD could bestow market power even if there are many units that could relieve the constraint of concern; and the ability of generators that are subject to ExD to raise their offers for subsequent intervals. Thus, if the proposal increases the frequency with which exception dispatches are declared competitive and are not mitigated, there is a chance that the exercise of market power will increase; therefore, it is necessary to continue to vigilantly monitor the bidding behavior of generators subjected to ExD. This also motivates the above recommendation (discussed in detail in Section 5) that units that are subjected to ExD be prohibited from raising its bid in subsequent intervals. We conclude the opinion with a discussion of the need for more data and understanding of the process by which ExD decisions are made, and their effects on bidding behavior and prices (Section 6).

2. Background on Exceptional Dispatch Mitigation and the ISO Proposal

The issues surrounding the mitigation of bids when units are subject to exceptional dispatch (ExD) have been discussed by the MSC several times over the past decade. In its May 7, 2008 Opinion,[3] the MSC outlined several principles that it believed should be followed when devising and implementing an offer mitigation mechanism for units subject to Exceptional Dispatch, and strongly supported capturing system constraints to the extent feasible rather than resorting to out-of-merit dispatch of units.

The October 30, 2012 ExD mitigation proposal by the CAISO is motivated by forthcoming changes in local market power mitigation (LMPM). In particular, upon implementing Phase 2 of the LMPM revisions, the current static path designations assessment, which presently determines the triggers for ExD mitigations, will transition to a dynamic competitive path assessment that flags paths as uncompetitive based on the application of a three-pivotal supplier test to transmission constraints that bind in RTPD. However, this transition introduces a gap in identifying and mitigating the offer prices of exceptionally dispatched resources that have local market power. The proposal addresses that gap as well as creating a set of default path designations that would be used if the dynamic assessment fails to produce a valid set of path designations.

[3] See Wolak *et al.*, Note 2, *infra.*

Under the CAISO's proposal, ExD mitigation would have four elements.

1. First, resources that are exceptionally dispatched for system energy will generally not be subject to mitigation because they presumably face competition from all resources within the California ISO.
2. Second, the offer prices of resources exceptionally dispatched to solve transmission constraints that are modeled in the dispatch software will be subject to mitigation depending on whether those constraints were found to be competitive in prior applications of the dynamic competitive path analysis.
3. Third, the offers of resources exceptionally dispatched to solve transmission constraints that are not modeled in the dispatch software will be subjected to offer price mitigation as there will be no prior applications of the dynamic competitive path assessment on which to base a determination of whether they are competitive or not.
4. The fourth element of the proposal does not actually concern mitigation of exceptional dispatch but instead addresses the mitigation of offer prices when the dynamic competitive path assessment fails to run. The offer prices of these resources will be subject to mitigation depending on whether they were found to be competitive in prior applications of the dynamic competitive path analysis.

Elements 1 and 3 are features of the existing system that would not be modified by the proposal. Elements 2 and 4 represent revisions to the current system.

3. General Comments on the Proposal and Economic Effects of Exceptional Dispatch

We support the CAISO's proposal as a bare minimum mitigation measure made necessary by changes to the process of designating transmission constraints as competitive or uncompetitive. The status quo approach will no longer be feasible, even if it were obviously preferable (which it is not). So-called "static" analyses of a constraint's competitiveness will no longer be performed as part of the local market-power mitigation process, and therefore cannot be used to determine whether the offers of a resource that is exceptionally dispatched should be subjected to mitigation.

We also believe, however, that the new rules will have to be closely monitored for their effectiveness. As with all things related to exceptional dispatch, there is little public information concerning exactly why resources are exceptionally dispatched or the process used to select the resources that are dispatched in this manner. It is therefore difficult to assess in advance whether the CAISO's proposal would adequately constrain the exercise of market power.

More generally, we note that exceptional dispatch has been a lingering problem since the implementation of MRTU. Despite periodic efforts to both analyze the sources and reduce the extent of exceptional dispatches, after several years there are still important questions left unanswered. ExD volume may be an indicator of weaknesses in the market's design and efficiency or, alternatively, might reflect substantial but transitory changes in the transmission system or resource mix.[4] These types of changes lead to unexpected operating conditions that could require significant changes to model in the unit commitment and or dispatch software. Higher levels of ExD both increase the potential competitive advantage of those units receiving such calls, and cause potential loss of market revenues for other units.

In particular, one consequence of the use of exceptional dispatch to solve constraints is that market prices in the constrained region will not reflect the impact of the constraint. On the one hand, this may necessitate bid-cost recovery (BCR) payments to resources that are dispatched out-of-merit to solve the constraint. At the same time, this also means that LMPs for other resources that contribute to relieving the constraint may be lower than would be the case if the constraint were fully modeled (while LMPs may be inflated for resources that increase congestion on the constraint).

A second consequence that is important in the context of the California ISO's proposed mitigation design is that, because the CAISO's dispatch software is not used to determine the dispatch, the resources selected for exceptional dispatch may not provide the least-cost means of resolving the constraint. A third consequence which we note, but which is not important to the present discussion, is that because the CAISO's dispatch software is not used to determine the dispatch, there may be a potential for adverse cost or reliability impacts if the operators fail to recognize that the output of the exceptionally dispatched resource adversely impacts other constraints.

4. Three Limitations of the Proposal

The CAISO's proposal for mitigation of exceptionally dispatched resources has three limitations. First, given the dynamic nature of transmission constraints, the proposed rules for assessing the competitiveness of modeled transmission constraints, which are backward looking, may not provide sufficient insight into the competitiveness of a specific modeled constraint at the time it triggers an ExD call. As an extreme case, a modeled constraint might have been solved using ExD rather than the dispatch software because there was something about the current constraint such that the operators determined that only a single resource could be used to resolve it. In this situation, a "modeled transmission constraint" is logged as the reason for the exceptional dispatch, but there is something different actually going on. Without knowing why a modeled transmission constraint is solved using exceptional dispatch rather than the dispatch software, we have no basis for assessing whether the resource selected actually faced any competition.

A second limitation is that by its very nature, any exceptional dispatch may endow a form of market power to the units selected. In some cases only one resource can relieve the constraint that is triggering the exceptional dispatch call. In those cases, the CAISO's proposal will operate as intended and the resource will be subjected to offer price mitigation when it is exceptionally dispatched. In other cases, however, there may be a number of units capable of providing the necessary congestion relief for a modeled constraint, so that the transmission constraint is typically determined to be competitive by the dynamic competitive path assessment. Under the CAISO's proposal, these resources would not be subject to offer price mitigation when excep-

[4] Such as the simultaneous outage of two units in the same nuclear plant.

tionally dispatched to solve the modeled transmission constraint. We cannot be confident, however, that this is the appropriate policy without further information regarding the reasons for the exceptional dispatch and the process behind the selection of the specific resource used. Even if there were five or six resources that could be used to solve a constraint (as would be the case for the many constraints the CAISO identified as modeled and competitive),[5] there is very little information about the process used to determine which resource would be exceptionally dispatched in situations like this. The selection of those units likely does not consider the offer prices amongst those units, but we have no specific knowledge of the criterion used to select units for exceptional dispatch or whether whatever criterion *is* applied is likely to be applied whenever similar conditions arise. Hence, we see a risk of circumstances in which resources that have been deemed competitive may nonetheless be able to take advantage of the prospect of an exceptional dispatch call to substantially raise their offer prices with little concern for competition in the event of such a call. Of course, in the absence of an ExD call, high offer prices will make a unit less likely to be in the market.

The possibility that units might not face competition in the exceptional dispatch process even on constraints determined to be competitive (based on the three-pivotal supplier test) might not be a problem if exceptional dispatch were a rare and largely unpredictable situation. In this case the probability of being exceptionally dispatched would be too low to warrant a resource raising its offer price to take advantage of the lack of competitive alternatives. Therefore, the potential for suppliers to abuse the prospect of an ExD call also depends upon how predictable such dispatch calls are. If calls were truly randomly distributed amongst many units, then we would be less concerned about the potential for circumvention of the CAISO's proposed mitigation design. However, an examination of the concentration of ExD overall indicates that, far from being randomly distributed, calls and energy volume are quite concentrated amongst a small number of units. In the twelve-month period from November 2011 through October 2012, about 70% of energy supplied through ExD came from just 5 units, and 90% of energy came from 20 units.[6]

A third limitation is that even if the operators carried out some kind of ad hoc economic analysis to choose the least-cost alternative before issuing ExD instructions to solve modeled transmission constraints, the resources initially selected to solve the constraint have the ability to substantially raise their offer prices *after* they are selected to take advantage of exceptional dispatch instructions having a number of hours of duration. Without information from the CAISO regarding the availability of tools or processes to monitor this, we do think it is reasonable to ask and expect the operators to continually re-evaluate their exceptional dispatch choices to account for changes in offer prices.

In light of the evidence we have seen, the CAISO proposal is far from overly aggressive in its mitigation. Absent further information from the CAISO regarding the circumstances in which

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[5] California ISO, Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 – Revised Draft Final Proposal, October 30, 2012 p. 12.

[6] Based on data supplied by the CAISO Department of Market Monitoring (personal communication). These data apply to all exceptionally dispatched resources, not just those dispatched to solve modeled transmission constraints, but in the absence of data showing a different pattern for such resources, we conclude that we should assume that many exceptional dispatches, for any reason, have an element of predictability.

individual resources are exceptionally dispatched, or the tools and processes available to the operators in selecting such resources, we cannot assess whether the CAISO proposal will be effective in preventing resources that are deemed competitive from taking advantage of the use of exceptional dispatch to solve modeled constraints. Recall that this procedure is replacing one in which the vast majority of paths were assumed uncompetitive by default. We expect that this procedure will result in more paths being evaluated and found to be competitive, and therefore constitutes a relaxation of mitigation relative to the status quo. On the other hand, although we have not reviewed bidding data, we understand from DMM that there has *not* historically been a problem with offer prices being raised by units that are exceptionally dispatched for competitive constraints.[7]

While we have concerns regarding the use of the CAISO's design for determining the mitigation of resources exceptionally dispatched to solve modeled transmission constraints, we have concluded that it should work well in the other situation in which it would be applied, namely occasions when the dynamic competitive path analysis fails to run or run properly. In these circumstances, the dispatch software would still be used to choose the least-cost solution, so resources submitting high offers and facing effective competition would not be selected. In addition, while the prior outcomes of the dynamic competitive path analysis do not guarantee that a resource will face effective competition in the interval in which the dynamic competitive path analysis fails, a resource that generally faces effective competition is unlikely to find it profitable to dramatically raise its offer price in the hope of getting lucky when the dynamic competitive path analysis fails to run. Moreover, we do not expect failures of the dynamic competitive path analysis to be common or predictable.

5. Recommendation to Freeze Bids on Multi-period ExD Calls

In addition to the mitigation proposed by the CAISO, we also make the following recommendation: in cases where a real-time exceptional dispatch call applies to multiple periods, a unit should not be allowed to change its bid from its level before the first ExD call. The reason for this recommendation is that we are concerned that units, having been informed of an ExD call for the first period, can raise their offer prices with the assurance that this exceptional dispatch will continue to guarantee sales for that unit. While there can be justifications for changing bids between a day-ahead offer and real-time, those reasons are much less compelling in the case of an intra-day change in offer prices. We therefore recommend that unmitigated bids be frozen at the level they were at as of the first ExD call.

6. The Need for More Transparency on Exceptional Dispatch

Although we support the CAISO's proposal for real-time mitigation of ExD offers, we also wish to emphasize the need for more information about the scope and consequences of exceptional

[7] A useful test in this regard would be to examine whether there is a difference in bidding behavior when units are dispatched for competitive constraints, relative to their bids when called upon to relieve uncompetitive constraints.

dispatch in general. In its opinion written in May, 2008,[8] the MSC supported the CAISO's original ExD design with the expectation that ExD would decline rapidly once the market matured.

> *Although we expect that during the initial stages of market operation under MRTU, the CAISO may need to make more frequent use of (ExD) instructions because of unexpected glitches in the market software, once this initial market start-up phase is completed, (ExD) instructions should occur rarely.*

In the same opinion, the MSC also recommended that:

> *the CAISO make every effort to reflect all significant and predictable constraints in its network model so that (ExD) instructions are truly that — exceptional — and not a significant and recurring source of revenue for generators.*

More than four years later, important questions about the role of ExD remain. Just how predictable are the constraints that trigger exceptional dispatch, and the calls made to specific units? Can those constraints be integrated into the market model, and how quickly? How can operators properly balance the need for reliability with the desire to not make exceptional dispatch designations to the same units every time a constraint is binding? The annual reports of the Department of Market Monitoring shed helpful light on these issues,[9] but more information is needed. We would like to see more systematic information about what is happening today when a resource is exceptionally dispatched, either for modeled or unmodeled reasons. Are they able to take advantage of this to raise offer prices? If not, why not?

Furthermore, why is it that exceptional dispatch is used to solve modeled transmission constraints and how do operators select the particular unit dispatched if the constraint is competitive (and hence there are at least four resources that can be chosen from)? The same questions apply for resources subjected to ExD because of system energy dispatches: if they are not mitigated today, what happens when the CAISO selects them? Do they raise their offer price in subsequent intervals?[10] How does the CAISO select them if they are meeting a general need for energy anywhere on the system?

Finally, we ask the same questions for resources subjected to ExD because system energy dispatches: if they are not mitigated today, what happens when the CAISO selects them? Do they raise their offer price in subsequent intervals?

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[8] Wolak *et al.*, Note 2, *supra.*

[9] For instance, see the DMM Annual Reports for 2009 (pp. 4.15 – 4.16, Fig 4.11), 2010 (pp. 101-103, Fig 4.13), and 2011 (pp. 158-159). Several useful metrics are reported, for instance:

- Prior to 2012, most ExD energy was "in-sequence" –- meaning that its bid was less than the LMP. 2012, unfortunately, had many instances where this was not so.
- The "above market" cost of out of sequence exceptional dispatches (measured as difference in LMP and the price paid for ExD) has been relatively small, except in 2012

[10] In the years 2009-2011, DMM reports that they have not seen participants raise bid prices after receiving ExD in prior day or hours. This year has unfortunately been different.

The stakeholder process involving this proposal has again highlighted unfinished business with respect to the sources and execution of exceptional dispatch. We recommend that the CAISO make a concerted effort to provide more transparency about exceptional dispatch in the hopes that this effort will also contribute to solutions that can reduce its use.

Attachment H –

ISO Governing Board memorandum and resolution

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President of Market & Infrastructure Development

Date: December 6, 2012

Re: **Decision on Mitigation of Exceptional Dispatch in Real-Time**

This memorandum requires Board action.

EXECUTIVE SUMMARY

The ISO will implement a new dynamic, in-market determination of whether a transmission constraint is competitive in the real-time market in the spring of 2013 as approved by the Board on July 14, 2011. This process will replace the static competitive path assessment that is used in the local market power mitigation process conducted in the hour-ahead market process. The static set of competitive paths is used today for both in-market dispatch and out-of-market exceptional dispatch. While in-market dispatch will utilize the dynamic competitive assessments, these assessments will not be reliable determinations of whether or not a transmission constraint is competitive for purposes of exceptional dispatch. If an exceptional dispatch is needed to manage congestion on a non-competitive constraint, the associated energy is settled using the mitigated exceptional dispatch energy settlement rules. This proposal addresses the gap in mitigation for exceptional dispatch.

Specifically, the proposal leverages the dynamic path competitiveness assessments from recent market outcomes to provide a set of designations that can be used to identify and mitigate local market power for exceptional dispatch. The approach uses two thresholds applied to recent designations that will trigger mitigation. Barring the two exceptions noted below, a transmission constraint for which an exceptional dispatch was made will be deemed uncompetitive, and mitigation applied, unless the following two conditions are met:

- **Significant in-market testing:** The constraint was congested and tested for competitiveness in ten or more hours in the most recent 60 days, and

- **Predominantly competitive:** The constraint was competitive in greater than 75 percent of congested hours.

Data from the real-time market are used to apply these tests for mitigation of exceptional dispatch. An exception to these rules is provided for Path 15 and Path 26 where these paths will be considered competitive if each is congested fewer than ten hours during the 60-day period.

This proposal provides adequate coverage for identifying local market power related to exceptional dispatch, strikes a balance between a highly conservative application of mitigation and under-mitigation of local market power, and incorporates recent system and market conditions through leveraging the new dynamic in-market competitive assessment.

The competitive path designations that are produced daily by this method also will be used as back-up designations for the dynamic in-market process and used in that mitigation process in the event the dynamic assessment of local market power fails.

Management recommends the Board approve the following motion:

> ***Moved, that the ISO Board of Governors approves the proposal regarding mitigation of exceptional dispatch, as described in the memorandum dated December 6, 2012; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

Filling a Gap within the Existing Framework

With implementation of the new real-time, dynamic, in-market competitive path assessment for local market power mitigation in the spring of 2013, the static competitive path assessment that is currently used for both in-market dispatch and out-of-market exceptional dispatch will no longer exist. While in-market dispatch will utilize the dynamic competitive assessments, these assessments will not be reliable determinations of whether or not a transmission constraint is competitive for purposes of exceptional dispatch.

The ISO may need to issue exceptional dispatches to resources to manage transmission constraints that are modeled in the market software but where the market software is not able to manage the congestion without manual intervention. It is possible, and anticipated, that the associated transmission constraints may not be congested during the same hours as the exceptional dispatch. The dynamic path assessment that will be implemented in the real time market in 2013 performs a competitive test only for transmission constraints that are congested. This leaves a gap in identifying and mitigating local market power in cases where congestion of a transmission constraint does not coincide with the exceptional dispatch made to manage that constraint. Accordingly, the ISO is proposing an alternative approach to determining whether or not a constraint is competitive for purposes of triggering the mitigated exceptional dispatch settlement.

Exceptional Dispatch for Modeled Constraints and Local Market Power

A primary function of the ISO nodal market is to economically manage congestion on the transmission grid at a sub-zonal level. There are circumstances where the real-time market is unable to do this effectively and so requires manual intervention by ISO system operators. A common characteristic of these circumstances is a discrepancy between the actual flow on a constraint and the flow that is calculated by the ISO market. Some of the more common causes of this type of discrepancy are transmission outages, variation in flow outside the ISO control area that impacts internal constraints, and insufficient or inaccurate telemetry.

There may be reliability issues in cases where the actual flow is higher than the flow perceived by the market and approaches the transmission constraint limit. The market may not adequately manage the constraint in these cases and will, instead, allow the actual flow to exceed the constraint limit, creating a reliability issue. ISO system operators may use a combination of manual intervention tools available to them, including exceptional dispatch, to address the discrepancies.

These modeled transmission constraints may have a limited set of generation resources available to help manage flow with an even more limited set of suppliers who control those resources. This circumstance may result in local market power. Within the market dispatch, local market power is created when a transmission constraint is binding and the supply of energy to relieve that congestion is limited in volume and ownership. There is an automated process for detecting and mitigating in-market local market power. In the case of exceptional dispatch, the congestion that helps create the local market power may be anticipated or perceived by the operator and not actually manifest in the market model. In these circumstances, an exceptional dispatch may be made under uncompetitive conditions despite the lack of market congestion in the dynamic assessment on the constraint that is being manually managed. The proposed exceptional dispatch mitigation rules address this circumstance.

There are also transmission constraints that are not modeled in the market software and consequently are managed through exceptional dispatch. Local market power is created by way of these constraints in a similar fashion: limited volume and ownership of supply to meet the requirement. Unlike modeled constraints, the competitiveness of these non-modeled constraints cannot be evaluated by the automated process in the market model. Further, the requirement or demand for these non-modeled constraints may not be specified in a way that can be easily quantified and used in an ad hoc study for competitiveness. Current rules for exceptional dispatch do trigger mitigation for non-modeled transmission. The proposal expressed in this memorandum does not alter the existing rules for mitigation of exceptional dispatch that manage non-modeled transmission constraints.

Thresholds to Identify and Mitigate Local Market Power in Exceptional Dispatch

The proposal leverages the dynamic competitiveness path assessments from recent market outcomes to provide a set of designations that can be used to identify and mitigate local market power for exceptional dispatch. The approach uses two thresholds applied to recent designations that will trigger mitigation except in instances where we are reasonably confident that the constraint is predominantly competitive.

The proposal states that a transmission constraint for which an exceptional dispatch was made will be deemed uncompetitive, and mitigation applied, unless the following two conditions are met:

- **Significant in-market testing:** The constraint was congested and tested for competitiveness in ten or more hours in the most recent 60 days, and

- **Predominantly competitive:** The constraint was competitive in greater than 75 percent of congested hours in the most recent 60 days.

Data from the real-time market are used to apply these tests, the results of which will be used to trigger mitigation of exceptional dispatch made to manage modeled transmission constraints.

An exception to these rules is provided for Path 15 and Path 26, where these paths will be considered competitive if the number of congested hours is less than ten during the 60-day period. Otherwise, the second rule that looks at whether the transmission constraint is predominantly competitive is applied in the same fashion as with the other constraints. This exception is included to recognize the largely competitive nature of the zones they connect and to avoid circumstances where these two inter-zonal interfaces trigger mitigation of an exceptional dispatch simply because they have not been sufficiently congested in the past 60 days.

This proposal provides adequate coverage for identifying local market power related to exceptional dispatch, strikes a balance between a highly conservative application of mitigation and under-mitigation of local market power, and incorporates recent system and market conditions through leveraging the new dynamic in-market competitive assessment.

Applying This Framework for Back-up Designations

The primary purpose of the proposed rules is to trigger application of local market power mitigation for exceptional dispatch made to manage modeled transmission constraints. They are also appropriate for providing back-up path designations in the event that the dynamic competitive assessment in the market model fails to produce valid results. In this case, the path designations resulting from the proposed rules also will be used in the mitigation process in the market software. Based on observed market run failures, the likelihood that these back-up designations will be used in the day-ahead market is extremely rare, as no failure has occurred since implementation in the spring of 2012, and failures in the real-time market are very infrequent.

POSITIONS OF THE PARTIES

Stakeholders expressed concern in three general areas. The first area of concern was with the practice of issuing exceptional dispatches for modeled transmission constraints instead of allowing the market to manage these constraints. Stakeholders noted that the ISO frequently issues exceptional dispatches and were concerned that this is likely a less economic solution compared to allowing the market to manage the congestion. As a result, exceptional dispatches do not provide a price signal indicating locational scarcity and the out-of-market energy may be lowering overall prices in the real time market.

The ISO has acknowledged the high frequency of exceptional dispatches in 2012 and has taken steps as part of a corporate goal to reduce the frequency. This effort will continue in 2013 to capture further efficiencies from the existing effort and comply with a FERC order that the ISO file a report on exceptional dispatch, highlighting efforts and results to reduce the need for these out-of-market transactions. The ISO also has ranked highly a market design initiative that will consider additional constraints, processes, or products to reduce exceptional dispatches as part of planning for next year.

Stakeholders also expressed concern regarding the lack of analysis and resulting automatic mitigation of exceptional dispatch made for non-modeled transmission constraints. Because these constraints are not modeled, they are not addressed by the in-market competitive assessment. Further, in many circumstances it may not be possible to perform an assessment of competitiveness.

Finally, stakeholders expressed concern that the basis for the thresholds was not well supported. An alternative approach using a well-established technique for statistical hypothesis testing was developed and presented to stakeholders. The statistical approach produced results consistent with the simple thresholds of the original proposal. The simple threshold approach was retained as the final proposal due to its consistency with the statistical model results and ease of implementation.

The specific threshold values of 10 hours of congestion and 75 percent competitive over 60 days were also questioned by stakeholders. The statistical model provided support for the 10 hour threshold, and the 75 percent observed historical competitiveness strikes a balance between a more conservative approach, which may apply mitigation in cases where it is not appropriate, and a less conservative approach where there is closer to even odds that local market power will go unidentified and unmitigated. Moreover, the rolling 60 day analysis is less than the quarterly review in place now but is long enough to capture seasonal differences and hours of potential congestion.

The Department of Market Monitoring and the Market Surveillance Committee both support the proposed approach for mitigating exceptional dispatches. See the attached Market Surveillance Committee opinion and stakeholder matrix for additional comments.

CONCLUSION

Management recommends that the Board approve the proposal for mitigation of exceptional dispatch as described in this memorandum. Recent observations and a resulting filing by the ISO this past summer highlight the importance of accurately identifying and mitigating local market power in exceptional dispatch. This proposal provides adequate coverage for identifying local market power related to exceptional dispatch, strikes a balance between a highly conservative application of mitigation and under-mitigation of local market power, and incorporates recent system and market conditions through leveraging the new dynamic in-market competitive assessment.

Attachment A

Stakeholder Process: Exceptional Dispatch Mitigation in Real-Time

Summary of Submitted Comments

Stakeholders submitted three rounds of written comments to the ISO on the following dates:

- Round One – August 3, 2012
- Round Two – September 20, 2012
- Round Three – November 14, 2012

Stakeholder comments are posted at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ExceptionalDispatchMitigationInRealTime.aspx

Other stakeholder efforts include:

- Stakeholder conference call – July 27, 2012
- Stakeholder conference call – September 11, 2012
- Stakeholder conference call – November 6, 2012

Management Proposal: Proposed Methodology based on Rolling Historical Data

Stakeholder Comments

California Public Utilities Commission	Calpine Corporation	California Department of Water Resources – State Water Project	Dynegy Marketing and Trade LLC	GenOn Energy	J.P. Morgan Ventures Energy Corporation	NRG Energy	Pacific Gas & Electric	Six Cities	Southern California Edison	Western Power Trading Forum
Concerns about the example impact study based on recent historical data, and the accuracy for out of model designations.	Opposes. Recommends that mitigation should be based on demonstrated market power, not by default; add non-modeled constraints to the model.	Supports	Opposes. Thinks the proposal is overly restrictive and will result in excessive mitigation. Questions why un-modeled constraints are deemed as uncompetitive.	Opposes. Thinks that non-modeled constraints need to be demonstrated as non-competitive for mitigation, not by default non-competitive.	Opposes. Thinks that the proposal results in “false positive” with default non-competitiveness.	Opposes. Expresses a concern about the increased mitigation due to the proposal; urges to propose a different method.	Supports. Requests ISO and DMM to provide a written report on the effectiveness of the mitigation approach, including Path 15 and 26, by December 31, 2013.	Supports. Encourages ISO to implement PG&E’s suggestion to monitor and report the effectiveness of the methodology and the special treatment for Path 15 and 26	Opposes. Thinks exceptional dispatch energy should be eliminated from supply portion for dynamical competitive path assessment; a static look-back based on historical data is not an actual test.	Opposes. Thinks that default non-competitiveness is too conservative; urges ISO to think of alternative methods.

Management Response:

Management has discussed three general methods during the latest paper and call, and expressed the proposed method is the best practical method. Management has demonstrated that statistical tests give results as the proposed triggers, which are a good balance given the asymmetric risk of under mitigation. Management has expressed the proposal follows the current tariff principle, and does not broaden the mitigation scope for un-modeled transmission constraints. Exclusion of exceptional dispatch energy from in-market mitigation is not part of this initiative. Further, it is appropriate to consider such energy in the in-market mitigation as it does impact the local market.

Management Proposal: Proposed Testing Thresholds of 10 hours and 75%

Stakeholder Comments

California Public Utilities Commission	Calpine Corporation	California Department of Water Resources – State Water Project	Dynegy Marketing and Trade LLC	GenOn Energy	J.P. Morgan Ventures Energy Corporation	NRG Energy	Pacific Gas & Electric	Six Cities	Southern California Edison	Western Power Trading Forum
Supports. Recommends revisiting the statistics of exceptional dispatch category, examining exceptional dispatch reasons, and evaluating real-time dynamic competitive path assessment failure.	Opposes.	Supports. Recommends that ISO monitor and evaluate whether the fixed thresholds and use of 60-days historical data are adequate.	Opposes.	Opposes.	Opposes.	Opposes. Suggests justifying the thresholds and trying a different approach.	Supports.	Supports.	Opposes. Does not think the thresholds are supported by data.	Opposes. Believe no justification for thresholds.

Management Response:

Management has discussed three general methods during the latest paper and call, and expressed the proposed method is the best practical method.

Management has demonstrated that statistical tests give results as the proposed triggers, which are a good balance given the asymmetric risk of under mitigation.

Management has expressed the proposal follows the current tariff principle, and does not broaden the mitigation scope for un-modeled transmission constraints.

Exclusion of exceptional dispatch energy from in-market mitigation is not part of this initiative. Further, it is appropriate to consider such energy in the in-market mitigation as it does impact the local market.

California ISO
Shaping a Renewed Future

Management Proposal: Proposed Special Treatment for Path 15 and 26										
Stakeholder Comments										
California Public Utilities Commission	Calpine Corporation	California Department of Water Resources – State Water Project	Dynegy Marketing and Trade LLC	GenOn Energy	J.P. Morgan Ventures Energy Corporation	NRG Energy	Pacific Gas & Electric	Six Cities	Southern California Edison	Western Power Trading Forum
No Comment.	No Comment.	Supports.	No Comment.				Opposes.		Opposes.	
Management Response:										
Management has expressed that Path 15 and 26 should be treated specially because operating experience and studies have shown that these two constraints have abundant suppliers during normal operating conditions, and they may not be binding that often. Therefore, a default competitive designation considers the special conditions for these two major constraints.										

Board of Governors **December 13-14, 2012** **Decision on Mitigation of Exceptional Dispatch in Real-Time**

Motion

Moved, that the ISO Board of Governors approves the proposal regarding mitigation of exceptional dispatch, as described in the memorandum dated December 6, 2012; and

Moved, that the ISO Board of Governors authorizes Management to make all the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.

Moved: Maullin **Second: Bhagwat**

Board Action: **Passed**	Vote Count: **5-0-0**
Bhagwat	Y
Foster	Y
Galiteva	Y
Maullin	Y
Olsen	Y

Motion Number: 2012-12-G2

Attachment I –

List of key dates in the market power mitigation stakeholder process

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

February 21, 2013

Date	Event/Due Date
October 1, 2010	ISO announces launch of new stakeholder process regarding local market power mitigation (LMPM) enhancements and issues paper entitled "Local Market Power Mitigation Enhancements Issue Paper"
October 8, 2010	ISO Market Surveillance Committee hosts meeting that includes discussion of ISO paper issued on October 1, ISO presentation entitled "Local Market Power Mitigation Enhancements Briefing," and ISO Market Surveillance Committee presentation entitled "Changes to Local Market Power Mitigation Due to Addition of Bid-in Demand and Convergence Bidding"
October 15, 2010	Due date for written stakeholder comments on matters discussed at October 8 meeting
March 18, 2011	ISO issues paper entitled "Local Market Power Mitigation Enhancements Straw Proposal," and ISO Department of Market Monitoring issues paper entitled "Proposed Modifications to Methodology for Competitive Path Designations for Local Market Power Mitigation"
March 25, 2011	ISO hosts stakeholder conference call that includes discussion of ISO paper and ISO Department of Market Monitoring paper issued on March 18, and ISO presentation entitled "Local Market Power Mitigation Enhancements"
April 1, 2011	Due date for written stakeholder comments on matters discussed on March 25 conference call
May 6, 2011	ISO issues paper entitled "Local Market Power Mitigation Enhancements Draft Final Proposal"
May 9, 2011	ISO issues paper entitled "A Retrospective Analysis of Local Market Power Mitigation Enhancements"
May 13, 2011	ISO hosts stakeholder meeting that includes discussion of ISO paper issued on May 6 and ISO presentation entitled "Local Market Power Mitigation Enhancements"
May 23, 2011	ISO Department of Market Monitoring issues paper entitled "Draft Final Proposal – Dynamic Competitive Path Assessment"; due date for written stakeholder comments on ISO paper issued on May 6
June 23, 2011	ISO issues paper entitled "Addendum to the Retrospective Analysis of Local Market Power Mitigation Enhancements"
July 5, 2011	ISO Department of Market Monitoring issues paper entitled "Revised Draft Final proposal – Dynamic Competitive Path Assessment"
July 6, 2011	ISO hosts stakeholder conference call that includes discussion of ISO papers issued on May 9 and June 23, ISO presentation entitled "Discussion of Addendum to the Retrospective Analysis," and ISO Department of Market

Date	Event/Due Date
	Monitoring presentation entitled “Dynamic Competitive Path Assessment”; ISO Market Surveillance Committee issues paper entitled “Final Opinion on Local Market Power Mitigation and Dynamic Competitive Path Assessment”; Keith Casey, Vice President, Market & Infrastructure Development for the ISO, provides memorandum to the ISO Governing Board entitled “Decision on Local Market Power Mitigation Enhancements”
July 14, 2011	ISO Governing Board Authorizes filing of tariff amendments to implement LMPM stage one and stage two enhancements
July 15, 2011	ISO issues draft tariff language to implement LMPM stage one enhancements
July 22, 2011	Due date for written stakeholder comments on draft tariff language issued on July 15
August 4, 2011	ISO hosts stakeholder conference call to discuss draft tariff language issued on July 15
August 26, 2011	ISO issues revised draft tariff language to implement LMPM stage one enhancements and paper entitled “Local Market Power Mitigation Enhancements – Stakeholder Comments”
September 2, 2011	Due date for written stakeholder comments on revised draft tariff language issued on August 26
September 13, 2011	ISO hosts stakeholder conference call to discuss revised draft tariff language and paper issued on August 26
October 28, 2011	ISO issues further revised draft tariff language to implement LMPM stage one enhancements
November 16, 2011	ISO files tariff amendment to implement LMPM stage one enhancements (Docket No. ER12-423-000)
March 1, 2012	Commission issues order accepting tariff amendment to implement LMPM stage one enhancements (Docket No. ER12-423-000)
July 20, 2012	ISO issues paper entitled “Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 – Issue Paper and Straw Proposal”
July 27, 2012	ISO hosts stakeholder conference call that includes discussion of paper issued on July 20 and ISO presentation entitled “Exceptional Dispatch Mitigation in Real Time”
August 3, 2012	Due date for written stakeholder comments on matters discussed on July 27 conference call
September 4, 2012	ISO issues paper entitled “Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 – Draft Final Proposal”

Date	Event/Due Date
September 11, 2012	ISO hosts stakeholder conference call that includes discussion of paper issued on September 4 and ISO presentation entitled “Draft Final Proposal: Exceptional Dispatch Mitigation in Real Time”
September 20, 2012	Due date for written stakeholder comments on matters discussed on September 11 conference call
October 31, 2012	ISO issues paper entitled “Mitigation for Exceptional Dispatch in LMPM Enhancements Phase 2 – Revised Draft Final Proposal”
November 6, 2012	ISO hosts stakeholder conference call that includes discussion of paper issued on October 31 and ISO presentation entitled “Revised Draft Final Proposal: Exceptional Dispatch Mitigation in Real Time”
November 14, 2012	Due date for written stakeholder comments on matters discussed on November 6 conference call
December 18, 2012	ISO issues draft tariff language to implement LMPM stage two enhancements
January 7, 2013	Due date for written stakeholder comments on draft tariff language issued on December 18
January 15, 2013	ISO hosts stakeholder conference call to discuss draft tariff language issued on December 18
January 28, 2013	ISO issued revised draft tariff language to implement LMPM stage two enhancements