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Opinion on Local Market Power Mitigation and Dynamic Competitive Path Assessment

by

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Summary

The Committee has been asked to provide an opinion on the proposed revisions of the California ISO's Local Market Power Mitigation (LMPM) and Competitive Path Assessment (CPA) procedures.[1] Three of the four MSC members came to a consensus on the desirability of the general changes proposed by the ISO, and are the authors of this document which sets forth their recommendations.[2]

We believe that the ISO's proposed changes to its local market power mitigation design and implementation are desirable from several standpoints. In addition to complying with FERC Orders,[3] they will allow the local market power mitigation process to consider all demand and supply bid into the day-ahead market (including virtual demand and supply bids and offers)[4] and eliminate the potential for anomalous outcomes arising from the current two pass approach. Further, by eliminating the need for two passes, these enhancements will potentially speed the process enough to allow other improvements to be implemented, in particular on-line (or dynamic) competitive path analysis.

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[1] " Local Market Power Mitigation Enhancements, Draft Final Proposal," California ISO, May 6, 2011, www.caiso.com/2b76/2b76e05c46990.pdf, and "Draft Final Proposal – Dynamic Competitive Path Assessment," California ISO, Department of Market Monitoring, May 23, 2011, www.caiso.com/2b88/2b8871044e720.pdf. Some additional details on the Dynamic CPA analysis are contained in "Proposed Modifications to Methodology for Competitive Path Designations for Local Market Power Mitigation," Department of Market Monitoring, March 18, 2011, http://www.caiso.com/2b45/2b45e56d50fb0.pdf.

[2] The fourth member, Dr. Steven Stoft, is not a coauthor of this document, and so "we" in this document should be interpreted as referring to the three signatories. We are indebted to Dr. Stoft's contributions to early drafts of this document. However, the responsibility for any opinions expressed or errors is ours alone.

[3] 116 FERC Paragraph 61,274, Sept 21, 2006 at 1089

[4] Instead of physical load based on the California ISO's load forecast and bids by physical generators, as used by the present LMPM procedure.

We conclude that the proposed changes will increase the accuracy of mitigation by targeting generators whose output will impact flows on transmission constraints that are designated as non-competitive and actually binding. Which constraints are binding and also represent a possible opportunity for exercising local market power depends very much on load conditions, network derates, and generator availability. Consequently, a dynamic assessment of the competitiveness of transmission constraints is desirable. We also conclude that the proposed LMPM and CPA changes are unlikely to increase opportunities for exercising local market power.

While the proposed design will likely mitigate the offer prices of more units than would the current design when non-competitive constraints are binding, this outcome is appropriate if the application of mitigation is reasonably well targeted to when non-competitive constraints are binding. Conversely, the proposed design will likely much less often mitigate offer prices when no non-competitive constraint is binding, which is also appropriate.

Although the changes are desirable overall, there are some elements of the proposed design and implementation whose performance should be subjected to further analysis prior to implementation, and then monitored by the California ISO and the Department of Market Monitoring following implementation. Some specific additional recommendations we offer include the following.

Because mitigation of generator offers in the real-time dispatch (RTD) market will be based on conditions in the earlier real-time pre-dispatch (RTPD) run, changes in load, generator, or network conditions between RTPD and RTD could result in false positives and false negatives for non-competitive path designations. The rate of false negatives could be decreased by expanding the number of non-competitive paths designated in RTPD by, for instance, allowing paths that are within, say, 2.5% or 5% of being congested to be considered for non-competitive designation. However, that would increase the rate of false positives. We recommend that analyses be performed of the consequences of false negatives and positives upon mitigation and prices in RTD under a range of conditions. If there are significant effects, then appropriate remedies may be called for. One such remedy might be to consider nearly binding constraints as candidates for non-competitive designation.

Another possible remedy is to base mitigation decisions in RTD upon flows and constraint costs in RTD, rather than in the earlier RTPD. This would require an additional RTD run in each interval. We recommend that the practicality and desirability of doing this be assessed, if it turns out that the above recommended analyses indicate that there are significant market price effects from false negatives and positives. Fortunately, there appears to be adequate time prior to the proposed mid-2012 implementation of changes to real-time LMPM and CPA to allow for these analyses and possible adjustments to the LMPM and CPA proposals.

A key element of the design and implementation whose performance needs to be monitored is the choice of the reference bus used to compute the "competitive price" floor on mitigation. There is a potential for this floor price to be inflated by the exercise of locational market power if an inappropriate location is used as the reference bus in computing this floor price. We tentatively support the ISO's recommendation that the Midway and Vincent buses be designated as the reference buses for purpose of LMPM. However, this designation should be subject to further verification that their use would not lead to consequential reference bus inflation.

A critical step in the competitive path assessment is the three pivotal supplier test. This test determines whether any set of three producers could withdraw sufficient generation that provides counterflow on congested constraints to cause an infeasible flow, given the existence of other potential sources of counterflow. If such an infeasibility would result, the constraint is designated as non-competitive in the CPA. We support the ISO proposal that ramp rates be used symmetrically in the real-time CPA to limit the amount of counterflow supply that might be withdrawn by potentially pivotal suppliers as well as to limit the amount of replacement counterflow that could be provided by other sources. The effect of these constraints on the designation of non-competitive paths and resulting mitigation and prices should be studied by the ISO. In addition, we recommend that forward schedules (from the day-ahead market) of generation limit how much potentially pivotal suppliers could profitably withdraw counterflow supply. At a minimum, the effect of the day-ahead schedule constraint upon path designation, mitigation, and subsequent prices should be assessed; if the differences are important, then the ISO should consider implementing that constraint in the real-time CPA process.

1. Introduction

The proposed local market power mitigation and competitive path assessment design are summarized in the ISO's "Local Market Power Mitigation Enhancements Draft Final Proposal,"[5] and "Draft Final Proposal – Dynamic Competitive Path Assessment."[6] Possible revisions of the ISO LMPM and CPA procedures along with preliminary versions of these proposals have been discussed at several previous MSC meetings on Oct. 15, 2009, Jan. 22, March 19, June 4, Oct. 8, 2010, and April 29, 2011.[7] We have also submitted a report requested by FERC on the performance of the LMPM mechanism during the first year of the new market.[8] In that report, we concluded that the LMPM mechanism was working satisfactorily, and that no changes were called for at that time. The LMPM and CPA design and implementation have also been reviewed in informal phone calls and in-person meetings between MSC members and ISO staff. In the April 29, 2011 MSC meeting, the latest versions of the proposals were reviewed, and discussed with

[5] Op. cit., Footnote 1.

[6] Op. cit., Footnote 1.

[7] www.caiso.com/271f/271f93564bde0.html

[8] F.A. Wolak, J. Bushnell, and B.F. Hobbs, "Report on the Performance of the California ISO's Local Market, Power Mitigation Mechanism During the First Year", Market Surveillance Committee of the California ISO, May 28, 2010, Submitted to the Federal Energy Regulatory Commission, www.caiso.com/27a4/27a4df0514630.pdf. Among the conclusions were the following. First, although the competitiveness of the market was very high, the first year was characterized by relatively low loads and little transmission congestion. Second, over the long-term too much reliance upon cost-based DEBs can weaken incentives for reducing costs, so it is still important for the CAISO to continue to improve the precision of the timing of its mitigation. Third, although there is significant promise in basing a LMPM mechanism on effective demand curves facing individual generators or collection of generators, further analysis is needed of its effectiveness and practicality before it can be recommended as a basis for a LMPM mechanism.

stakeholders and ISO staff. We appreciate the extensive comments that have been provided by stakeholders during these meetings, in phone conversations, and as written submissions in response to ISO requests for comments which have helped inform us in the preparation of this opinion.

The market power mitigation provisions in the California ISO tariff are based upon the principle that, system wide, the market is large enough and includes enough competitors to provide reasonable, competitive outcomes. Although even large geographic markets can be subject to the exercise of market power, experience has shown that a regional market with many potential suppliers and robust forward contracting can produce competitive prices and supply.

If the market is divided by binding transmission constraints, however, suppliers within the resulting sub-markets can have an unacceptable degree of local market power. This local market power can be more than a transient phenomenon as it can be difficult or impossible to site new generation in many transmission constrained "load pockets." The potentially high degree of market power created by transmission constraints, combined with a lack of forward contracting by either consumers or load serving entities in retail access electricity markets, can warrant more active and extensive forms of regulation than are normally applied in other markets. This regulation can in some circumstances include the "mitigation" or adjustment of supplier offers to a level estimated to be competitive.

All ISO coordinated spot electricity markets in the U.S. feature some form of local market power mitigation. Each features three broad steps to the mitigation process. First, conditions that define a market as 'local' are established. Second, estimated competitive offer prices are determined for some or all suppliers within the local market. The third step is to define conditions under which the market operator mitigates the offers of some or all suppliers to the estimated competitive level.

Under the current market design in California, the approach to this process has been to identify certain transmission constraints as creating the potential for unacceptable levels of local market power. These constraints are termed non-competitive. Other constraints, while potentially binding, are served by a broad enough set of potential suppliers for the impacted region to remain competitive when the constraints are binding. One goal of the current design is to avoid modifying market participant's bids unless they potentially reflect the exercise of market power arising from binding non-competitive transmission constraints. In this way, market processes would determine supply offers except at times and in regions in which there is an unacceptably high potential for the exercise of local market power.

While this philosophy of local market power mitigation is relatively simple, its implementation can be complex. The determination of which transmission constraints are sufficiently competitive such that no offer price mitigation is necessary and which constraints are potentially non-competitive involves a degree of estimation and the application of rough heuristics. The competitiveness of transmission paths, as well as the identity of the binding transmission constraints, can change as a result of generation and transmission outages or other changes in system conditions. Lastly, the competitiveness of transmission constraints can be impacted by other constraints such as ramp rate limitations.

The CAISO is undertaking a major redesign of its implementation of this approach to market power mitigation. The precipitating event is the need, ordered by FERC, to properly accommodate convergence bidding and other forms of demand bids into the mitigation process. However, as we describe below, the new design also offers other advantages over the current procedures.

In this opinion we comment on the key attributes of the changes to the CAISO's local market power mitigation methodology. Section 2 provides an overview of the proposed local market power mitigation design. Section 3 discusses the potential for the exercise of locational market power to inflate the floor price used for mitigation if the reference bus price is not selected appropriately. Section 4 discusses an alternative approach to defining the competitive constraint floor price proposed by PG&E. Section 5 discusses the likely impact of the revised design on the extent of mitigation. Finally, Section 6 summarizes our conclusions, including recommendations for further investigation on the effectiveness of LMPM and CPA mechanisms.

2. Overview of the Proposed Local Market Power Mitigation Design

The proposed new local market power mitigation process would have five steps:

1) An "all-constraints run" based on unmitigated generator offer prices.
2) Identification of binding transmission constraints and application of competitive path analysis to identify non-competitive constraints.
3) Determination of the reference bus and recalculation of each LMP's congestion component from the all-constraints run.
4) Calculation of floor price for mitigation by setting congestion components of non-competitive constraints to zero.
5) Application of mitigation to relevant units.

Each of these steps is summarized below in a separate subsection, together with some of our observations on the likely impact of the proposed changes on market competitiveness. We discuss some particular issues in more detail in subsequent sections.

2.1 Step 1: All-constraints run

2.1.1 Summary of Step 1. The purpose of the all-constraints run is to identify the transmission constraints that will be binding in the market run and may therefore give rise to the potential for the exercise of locational market power.

Under the present local market power mitigation process, a competitive constraints run precedes the all-constraints run in the local market power mitigation process, and differences in optimal generator schedules between the two runs are used to identify generators whose offer prices are potentially subject to mitigation. These are the generators who would be "out of the market" due to the level of their offer prices in the absence of binding non-competitive constraints, but were dispatched when the non-competitive constraints are enforced. One of the major changes to the mitigation process is the elimination of the competitive constraints run and replacement of the previous two step process with a single step.

This single step dispatches the market with all constraints enforced, and decomposes prices into four components: the energy price (the price at the designated swing bus), the loss component, a congestion component for competitive constraints, and a congestion component for non-competitive constraints. Under the proposed new local market power mitigation process, in the day-ahead market, the all-constraints run comprises a full unit commitment and dispatch, enforcing all transmission constraints and ancillary service requirements. That run will be carried out using unmitigated generator offer prices and the same physical and virtual load bids and virtual supply offers that will be used to clear the day-ahead market.

Because the all-constraints run of the day-ahead market will be based on the same bids, offers, and transmission model that will be used to determine day-ahead prices and schedules, in the absence of mitigation, the same constraints that bind in the LMPM all-constraints run will also bind in the day-ahead market. However, it is possible for transmission constraints that were not binding in the LMPM all-constraints run to bind in the day-ahead market as a result of the application of mitigation to offer prices impacting non-competitive constraints. The overall design will nevertheless cause any non-competitive offers that have a defined level of impact on these constraints to be mitigated as well, as will be discussed in greater detail in section 2.4 below.

The all-constraints run in the real-time market will be carried out in the HASP and in RTPD based on unmitigated generation offer prices and the applicable California ISO load forecast for the relevant period. The all-constraints run in the HASP and RTPD comprises a full unit commitment (of units capable of coming on line within the relevant time frame) and dispatch, enforcing all transmission constraints and ancillary service requirements. This run is carried out using unmitigated generator offer prices. Because this run will be carried out prior to the actual real-time dispatch interval in which the mitigation will be applied, there is a potential for different transmission constraints to be binding in the all-constraints run than bind in real-time. This could be a result of differences in loads, generator status and projected output, and network conditions, as well as offer price mitigation.

2.1.2 Choice of Congestion Threshold and Inconsistency between RTPD and RTD. The proposal to base real-time mitigation upon RTPD conditions is a definite improvement compared to basing it on earlier conditions, such as in HASP. There remains the potential for differences in conditions between RTPD and RTD such that mitigation based on RTPD conditions might miss some binding competitive constraints at the time of real-time dispatch. We discuss these issues in this subsection.

One of the important design choices entailed in the proposed local market power mitigation process is the threshold for identifying transmission constraints as binding in real-time. Because the RTPD run in which potentially binding non-competitive transmission constraints would be identified initializes prior to the RTD runs in which mitigation would be applied, there is a possibility for transmission constraints to be binding in RTD that were not identified as binding in the prior RTPD run. Conversely, it is also possible for transmission constraints that were binding in RTPD to be non-binding in RTD. These differences can arise as a result of load forecast errors in RTPD, changes in generation output relative to the dispatch (which could include both under-generation or over-generation by conventional resources and variations in the projected output of intermittent resources), transmission or generation outages, and upward or downward ramp constraints that constrain generator output in the five minute time frame of RTD but not in the 15 minute time frame of RTPD.

If mitigation is applied in RTD only to non-competitive transmission constraints that are identified as binding in RTPD, there will be a potential for real-time offer prices to be unmitigated during an RTD interval which significant impact non-competitive constraints that are in fact binding. The Department of Market Monitoring has analyzed the potential for mis-identification of binding constraints as a result of these differences using historical California ISO constraint data and reported their findings in a March 18, 2011 White Paper.[9] These data showed that if the constraints subjected to mitigation were determined based on whether they were binding in the prior RTPD run, and then in about 2.7% of the fifteen minute intervals, one or more constraints would be binding in RTD that had not been identified as non-competitive paths. This results in offer prices not being mitigated that potentially should have been. Since 27% of intervals experience congestion in RTPD, with an average of 1.1 constraints being binding, the implication is that approximately 10% of the binding RTD constraints that should have been identified as non-competitive were not. Conversely, these data show that around 15% of the constraints identified as binding in RTPD were not binding in RTD.[10]

The same report from the Department of Market Monitoring shows that if the threshold for applying competitive path analysis were changed to be based on whether flows were greater than or equal to 97.5% of the limit in RTPD, the proportion of intervals (and constraints) binding in RTD that would not have been subjected to competitive path analysis would fall to 2.1%, a reduction of 0.6% compared to the 100% threshold case. Conversely, however, the proportion of constraints identified as binding (and potentially triggering mitigation) that would not bind in real-time would rise to 12.4%, an increase of almost 8%. In other words, roughly 1/3 of the constraints subjected to competitive path analysis would not actually be binding in real-time.[11]

The Department of Market Monitoring's draft final proposal proposes that only constraints that are binding in RTPD would be eligible to be designated as non-competitive paths in the real-time market.[12] In evaluating this element of the draft final proposal, it is important to understand that

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[9] California ISO, Department of Market Monitoring, "Proposed Modifications to Methodology for Competitive Path Designations for Local Market Power Mitigation," March 18, 2011, http://www.caiso.com/2b45/2b45e56d50fb0.pdf, pp. 10-12.

[10] Ibid.; based upon 4.5% of the RTPD intervals having one or more binding constraints that were not binding in RTD; an average of 1.1 constraints per interval being binding in RTPD; and 27.4% of intervals having such binding constraints.

[11] See ibid., Table 3, p. 11. These data also show that lowering the threshold to flows exceeding 95% of the limit would only reduce the proportion of constraints not identified as binding in RTPD to 1.9%, while 24.7% of the constraints identified as binding in RTPD would not be binding in RTD, so for a large fraction of the intervals that competitive path analysis was applied, the constraint would not actually be binding in RTD.

[12] California ISO, Department of Market Monitoring, "Draft Final Proposal – Dynamic Competitive Path Assessment," May 23, 2011 p. 7.

the situation in which competitive path analysis is not applied because a constraint is not binding in RTPD should not be interpreted as a 1 in 10 chance that high offer prices will go unmitigated in RTD; therefore, it is fundamentally different from the situation in which RTPD fails to run correctly.[13] If a constraint is not binding in RTPD this implies that there is enough supply offered at in-merit prices to solve the constraint in RTPD without out-of-order redispatch. Hence, this is by definition not a situation in which all supply behind the constraint is offered at high prices, because if that were the case, the constraint would be binding in RTPD.

One situation in which a constraint could be binding in RTD but not in RTPD would be a one in which a slightly higher load forecast in RTD than in RTPD causes a constraint to become slightly binding in RTD and a small amount of out-of-merit energy is needed to solve the constraint. This kind of minor forecasting difference between RTPD and RTD is not likely to be a situation conducive to the exercise of market power. Another situation in which a non-binding RTPD constraint might become binding in RTD would be one in which the incremental cost of power on the constrained down side of the constraint is substantially lower in RTD than in RTPD, as would be the case if the forecast for intermittent energy output were materially higher in RTD than in RTPD. This would also not likely be a situation reflecting the exercise of market power, as the lack of congestion in RTPD would indicate that the offer prices of the generation within the constrained region were in line with the offer prices of thermal generation outside the region. In this situation, the constraint only becomes binding in RTD because the price of power outside the constrained region dropped due to the increase in supply of very low cost non-thermal energy.

We do not have any specific basis for questioning the California ISO Department of Market Monitoring's assessment that applying competitive path analysis only to transmission constraints that are binding in RTPD will not permit the exercise of locational market power. However, we have recommended that DMM analyze the 2.7% of the intervals in which a constraint was binding in RTD but not in RTPD from a variety of perspectives to allow us and DMM to better assess the impact of not imposing mitigation in these intervals before making a final decision on how they would be treated within the proposed design. The concern here is with possible under-mitigation rather than over-mitigation, compared with the ideal of undertaking all CPA and mitigation on a five minute basis in real time. If it is decided to proceed with the approach currently proposed by the DMM, it would be desirable for the Department of Market Monitoring to track the market outcomes in such intervals following implementation of the proposed design and report on the relationship between RTD and RTPD congestion and prices during the impacted intervals so that any changes in the apparent historical patterns would be identified and appropriate remedies, if any, recommended.[14]

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[13] The Department of Market Monitoring proposes to apply after the fact mitigation in this situation, which is discussed later in Section 2.

[14] It is possible, for example, to reduce the likelihood that constraints that are binding in RTD would be missed in the RTPD by restricting transmission capacity by a small amount in the pre-market CPA runs described in Section 2.2.1; this should result in more congested lines and more mitigation. However, this approach has a serious disadvantage of possibly resulting in very different patterns of dispatch and congestion than actually occurs in the market, perhaps yielding large unintended consequences. Another alternative is basing mitigation on constraints that are not quite binding, using, say, a 2.5% threshold; however, mitigation would then have to be triggered by a rule other than the positive non-competitive LMP

2.1.3 Assessment of Step 1 (All-Constraints Run). The proposed design of this step reflects three significant improvements relative to the current implementation of local market power mitigation. First, in the day-ahead market, the local market power mitigation process (which will consist only of an all-constraints run) will account for virtual supply and demand bids, which will better align the outcome of this run with the outcomes in the day-ahead market. Because the current local market power mitigation design does not include virtual demand and supply offers and is based on the California ISO's load forecast rather than actual physical load bids, there is a potential for different constraints to bind in the all-constraints run of the current local market power mitigation process than bind in the day-ahead market. This potential will be eliminated in the new design.

Second, in both the day-ahead market and the HASP (or RTPD), the dispatch in the all-constraints run will be based on actual offer prices. In contrast, under the present system, plants dispatched in the competitive-constraint run have their bids modified in the all-constraints run (by being offered at prices less than actual offer prices) in order to prevent decreases in their output unless required by non-competitive transmission constraints.[15] This proposed change will eliminate another potential cause for spurious mitigation in the day-ahead market or in real-time.

Third, by replacing the current two-pass approach (competitive constraints run followed by all-constraints run) with a single all-constraints run, the proposed design reduces the required processing time. This reduction in processing time is particularly important because it is expected to allow the California ISO to implement an on-line application of competitive path analysis, which we summarize next, and discuss at length later in this opinion.

2.2 Step 2: Competitive Path Analysis

2.2.1 Summary of Step 2. The first tenet of CAISO's philosophy of market-power mitigation is to identify locally uncompetitive areas, and then apply mitigation to offer prices potentially reflecting the exercise of market power only in those areas—hence this process is referred to as local market-power mitigation (LMPM). The second tenet is to use structural methods to identify the potentially uncompetitive areas. Structural methods take into account transmission constraints, load levels, and the amount and ownership of generation, but not the costs or offers of suppliers.

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component rule described in Section 2.5. The DMM's analysis indicated that use of such a threshold would result in many more false positives (non-competitive constraints that turn out to be nonbinding in RTD) than the reduction in false negatives (nonbinding RTPD constraints that turn out to be binding in RTD). Our recommendation is that the DMM examine what actually happens in the intervals in which constraints bind in RTD but not in RTPD, and assess whether there is anything troublesome going on. If not, no changes are needed. If something troublesome is observed, a remedy can perhaps be tailored based on what the issue is.

[15] A member of this Committee previously identified this feature of the present LMPM mechanism as problematic in the LECG review of the new market design (S.M. Harvey, S.L. Pope, and W.H. Hogan, "Comments on the California ISO MRTU LMP Market Design," Prepared for the California ISO by the LECG, LLC, Cambridge, MA, Feb. 23, 2005).

As a consequence, there is no attempt to directly identify the exercise of market power, or to calculate the profitability of its exercise. Instead, certain local areas are identified as having a structure that is likely to permit the exercise of market power, and the offers of generators within these areas are mitigated. The key elements of an uncompetitive local market structure are a transmission constraint and concentrated control of supply.

The point of using the structural test as a screen is to reduce errors of over-mitigation (mitigation when none is needed), while mitigating offer prices in regions in which the potential to exercise market power may exist. These goals will be realized if competitive areas (areas not identified as uncompetitive) are, with high probability, actually competitive. In this case, any offers in a competitive area that appear to be an exercise of market power because they exceed the estimated competitive offer price must be the result of imperfections in the calculation of competitive offer prices (the default energy bid in California) or bidder error. Hence the success of this approach depends on the ability of the structural methods to eliminate from consideration only (or almost only) areas that are highly likely to be competitive. A major challenge with using a structural approach in real-time is that the market structure can vary with the status of the network and other system conditions.

The areas that are evaluated for the exercise of market power are defined by transmission constraints, since it is these constraints that allow the exercise of local market power. If a certain path is constrained and uncompetitive, then generators who can contribute to relieving that constraint may have market power and are subjected to offer price mitigation. The competitive path analysis process can be viewed as having three substeps (labeled 2.1 through 2.3, since we label the CPA as Step 2).

- 2.1 Perform a market run to identify critical constraints.[16]
- 2.2 Select a subset of "candidate paths" from the list of critical constraints.
- 2.3 Apply the three-pivotal-supplier test to all candidate paths. Those that fail are treated as non-competitive paths for the purpose of offer price mitigation.

Step 2.1 is performed by an all-constraints market run, and the list of critical constraints includes all lines that are within 15 percent of being congested. Like the present CPA process, there is also a list of grandfathered constraints that are a priori deemed competitive (such as Path 15, Path 26, and interties). Unlike the present procedure, there is no threshold on the number of hours that a constraint must be binding in order to be eligible to be tested and potentially designated as competitive. The present procedure does not test constraints that are binding less than 500 hours/year, thereby automatically designating them as non-competitive.

Step 2.2 requires the choice of a cutoff threshold value for the amount of flow in order for a constraint to be considered a candidate path. The threshold is expressed as a percentage by which

[16] Each all-constraints run includes a list of critical constraints on which the scheduled flow is at least 85 percent of the constraint limit. We can choose to use this entire list, or choose a different threshold (i.e., where scheduled flow is at least 95 percent of the limit.) From "Proposed Modifications to Methodology for Competitive Path Designations for Local Market Power Mitigation," Department of Market Monitoring, March 18, 2011, www.caiso.com/2b45/2b45e56d50fb0.pdf.

the flow limit exceeds the flow itself. The Department of Market Monitoring currently proposes that this threshold be set to zero, meaning that only constraints that are actually congested in the all-constraints run would be included in the list of candidate paths. Some MSC members feel that the threshold should be raised to at least 2.5 percent and possibly higher. This is discussed further below.

Step 2.3 is to test all candidate paths with the three-pivotal-supplier (3-PS) test, which is now based on the residual supply index (RSI). As noted in step 2, this test is applied to all constraints that are binding in the all-constraints run (and some that are not if the threshold is positive).[17] The previous 3-PS test required extensive staff hours to implement and was performed on a quarterly basis for a small number of projected market conditions and a limited number of paths. But the use of the RSI streamlines the 3-PS test and allows its automation. All candidate paths that fail the 3-PS test are deemed to be uncompetitive.

The application of the three-pivotal-supplier test to constraints in the day-ahead market will test whether the total congestion relief provided by the physical supply offers of the fringe (which we define as suppliers other than the top 3, as measured by total congestion relief available from physical resources) plus relief provided by virtual supply offers of fringe suppliers that cleared in the all-constraints run, is sufficient to relieve the constraint without dispatching any of the supply offered by the top three suppliers[18] In other words, can the potential 'demand' for counterflow created by withdrawal of generation by any set of three suppliers be met by 'supply' of counterflow in the form of increased output from other suppliers? Only the cleared virtual supply offers are included to ensure that out-of-market virtual supply offers cannot be used to circumvent the three-pivotal-supplier test by inflating supply. Cleared virtual supply offers are included to ensure that the congestion relief required by cleared virtual demand bids does not overstate the required relief.

Importantly, the physical supply of the competitive fringe includes all supply offered, regardless of whether the units able to provide supply were committed in the all-constraints run and disregarding ramp constraints. We find this approach to be reasonable, given the ability of the day-ahead process to commit additional generation as needed, and to ramp units up prior to the hour in which they are needed.

The application of the three-pivotal supplier test to constraints in real-time will be carried out based on an RTPD all-constraints run. The supply available in this run will include neither virtual supply nor supply from units that cannot be committed within the time frame of the RTPD evaluation. In addition, we understand that the DMM envisions utilizing the 15 minute ramp rate used in RTPD to define the amount of additional supply available from the competitive fringe. Conversely, we understand that DMM envisions calculating the amount of relief needed by limit-

[17] The application of the competitive path analysis does not depend on the decomposition of the congestion components; rather, that decomposition is conditional on which constraints are identified as non-competitive in this step.

[18] Our understanding is that supply from the top three suppliers is defined as including all generation owned by such suppliers that contributes counterflow (negative swing factors), and so excludes their generators that have positive swing factors (i.e., would exacerbate congestion).

ing withdrawal of supply by the top three suppliers to at most 30 minutes of ramp relative to their dispatch in RTPD.[19]

The only output of the competitive path analysis is a list of uncompetitive paths. No other information about these paths is provided. The constrained uncompetitive paths will be used to evaluate the bids of generators. Generators that can relieve these constraints will be subject to mitigation. Exactly how this is determined is discussed in Sections 2.3-2.5, below.

The dynamic CPA is proposed to be performed at three different points in time leading up to any given 5-minute real-time dispatch (RTD).

1. Pre-Market Day-Ahead all-constraints run.
    a. There is one such run for each hour, all done at the same time, a day ahead.
2. Pre-market HASP run.
    a. There are 24 such runs, performed 1.22 hours before the start of each RT hour.
3. After each 15-minute ancillary service procurement run in RTPD.
    a. That occurs 23 minutes before the start of each quarter hour (96 times/day).
    b. The mitigations applied to any quarter-hour also apply to all subsequent quarter hours within that hour.

In real-time, LMPM's identification of binding constraints and hence ultimately units to be mitigated in the real-time dispatch is based on the RTPD run used to perform the CPA. This leads to the possibility that a constraint might be binding in RTPD (or within the defined threshold of binding in RTPD) but not binding in real-time, or conversely, not binding in RTPD but binding in real-time. If possible, it would be better to identify units to be mitigated based on the non-competitive constraints that are binding in RTD, when system conditions may differ significantly from RTPD.[20] Such an approach could be implemented with a two-pass design in RTD. The first pass would determine constrained paths using unmitigated offer prices, then local market power mitigation would be applied to non-competitive constraints identified as binding in the first pass (which essentially becomes an all-constraints run for the purposes of Steps 3-5 of LMPM), and the second pass would rerun the market using mitigated offer prices, starting from the first-pass solution. We recognize that this approach may be infeasible from a software perspective, and if feasible the cost of implementing this approach would need to be balanced against the improvements in accuracy of the mitigation, which may or may not be significant.

The "true" potential market power faced by a firm is defined by its residual demand curve. The residual demand is the demand faced by a firm or group of firms after accounting for the supply (or offers to supply) of all the other firms in the market. Measures such as the pivotal supplier and RSI attempt to approximate with a simple calculation an important characteristic of the residual demand curve: whether it becomes sufficiently inelastic in a relevant range to offer opportunities for exercising significant market power. For example, if one firm is a pivotal supplier,

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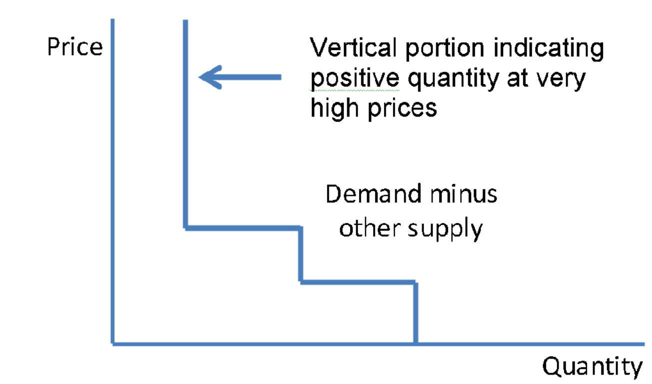
[19] This understanding is based on conversations with DMM staff on June 23 and 26 and is not reflected in past white papers or presentations.

[20] Even in the Pre-Market Day-Ahead CPA, the constraints are not identical (for a number of technical reasons) to the constraints in the actual Market run.

this means that the potential supply of all other firms is insufficient to meet all demand. In this case, the pivotal firm can be thought of as a monopoly supplier to the residual demand or as a dominant firm that competes with a competitive fringe whose generation capacity can only displace a portion of the dominant firm's sales. Transmission constraints can be a key factor in making firms pivotal because they limit the potential for more distant supply to serve the "local" market.

2.2.2 Theory and Implementation of the Three-Pivotal-Supplier (3-PS) Test. The "true" potential market power available to a firm is related to its residual (or "effective") demand curve. The residual demand is the demand faced by a supplier or group of suppliers after accounting for the offers to supply of all the other suppliers in the market and of any demand elasticity. Pivotal-supplier tests can be viewed as a restrictive examination of the residual demand curves faced by various groups of suppliers. If a supplier faces a residual demand curve whose leftmost segment fails to intersect the price axis and is perfectly inelastic (vertical), this means that raising the price further will not reduce quantity demanded. This indicates that this supplier could exercise unlimited monopoly power if it acted in a coordinated fashion. Such a demand curve is shown in Figure 1.

Figure 1. Residual Demand Curve for Pivotal Supplier



Importantly, the concept of a single pivotal supplier captures only the most extreme potential market power conditions. Even if a supplier is not individually pivotal, the supplier may be able exercise significant market power. Also, a group of suppliers may be able to successfully raise prices above competitive levels under some conditions, even if they do not coordinate explicitly with each other. For the latter reason, it is therefore appropriate to consider circumstances beyond which a single firm is pivotal in assessing potential market power.

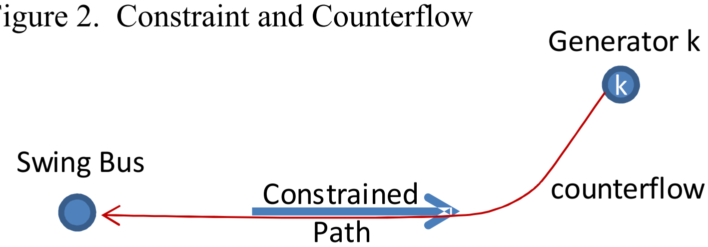
The 3-PS test is only a rough approximation of the true potential market power possessed by suppliers at any given moment. In fact, it is so rough that it is easy to construct examples in which suppliers can easily exercise significant market power yet pass the test, and other examples in which they have little or no market power yet fail the test.[21] The complexity of the miti-

[21] As the MSC has stated in a previous opinion, a full residual supply curve analysis, if practical, would be a more reliable way to identify market power. See Wolak et al., op. cit.

gation process (and the desire to carry it out in real-time) requires calculations that can be carried out quickly. Hence, carrying out the Three Pivotal Supplier test in real-time limits the accuracy of the test from this perspective, but it improves the accuracy of the test because it is applied to actual system conditions.

More specifically, the three pivotal-supplier test is applied to a constrained path, or to a potentially constrained path. The test is passed for a set of suppliers if they can be removed from the dispatch while load is still served and without violating the constraint. We now describe its application in the day-ahead market.

Figure 2. Constraint and Counterflow



The test involves only generators in the set of generators K that provide counterflow. Some of the generators also belong to the subset P of K that includes only generators belonging to the set of three suppliers being tested that provide counterflow. The set $K-P$ is the set of generators in K but not in P. We make the following definitions:

- CF(K, init) = total counterflow with the initial generation output.
- CF($K-P$, max) = the maximum counterflow that the generators not being tested can produce.

The residual supply index for this test is then given by:

- RSI = CF($K-P$, max) / CF(K, init)

If RSI < 1, then the tested suppliers have failed the pivotal supplier test and are declared to be pivotal. More importantly, the constraint has been found to be non-competitive. This assumes that the generators in K can withdraw their entire output; in real-time, this may not be possible due to ramping constraints and day-ahead schedules, and the ISO proposes to consider ramp limits and apply the 3-PS test somewhat differently. This is discussed further below.

The proposed CPA analysis tests the three suppliers (including all generators controlled by each supplier) that provide the most counterflow, and if that set of three is pivotal, then the constraint (or near-constraint) is deemed uncompetitive. Only net sellers (at the system level) are included as potentially pivotal suppliers, consistent with the present LMPM procedure.[22]

[22] Although this restriction does not appear in the ISO proposal, this intention was communicated to us on June 26 by ISO staff. . As a result, generation owned by the major utilities in the state will not be considered. . Given that they are subject to rate-of-return regulation, so that extra gross margin earned by exercising local market power would be refunded to ratepayers, their incentive to exercise such market

A challenge in applying the 3-PS test (or, for that matter, quantifying the full residual demand curve) is that it is necessary to define the constraints that would limit the ability of other generators to expand output. In the day-ahead market, it is reasonable to assume in the 3-PS test that all generators available for commitment day-ahead could be committed and produce output at their full capacity (in the case of suppliers providing counterflow on a constraint) or can drop output to zero (in the case of the candidate pivotal suppliers, who would withhold counterflow). This is consistent with the present quarterly approach to CPA, and is the method that the ISO proposes for application in the enhanced local market power mitigation design.

It is our understanding that the day-ahead RSI results portrayed in the Department of Market Monitoring's April 29, 2011 presentation[23] were compiled generally consistent with this methodology and hence provide a reasonable indication of how the test would perform on these constraints relative to the current methodology.[24]

However, in the HASP and RTPD CPA analyses, there are additional constraints. The generators who can supply counterflow in real-time are limited in their ability to change output by ramping constraints. We take the view that the ramp constrained supply of the competitive fringe in real-time should be compared to the total counterflow needed to meet incremental 'demand' for counterflow resulting from actions that the top three suppliers can take within the same time interval which might, for instance, be limited by their downward ramp rates.[25]

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power is significantly less than net sellers. However, there can be cases where utilities own generation outside their service territory and conceivably the exercise of local market power could benefit their ratepayers at the expense of consumers near that generation. DMM should monitor the behavior of such generators to verify that they are not bidding in a manner consistent with the exercise of local market power.

[23] Jeff McDonald, Department of Market Monitoring, "Dynamic assessment of path competitiveness," April 29, 2011 p. 9.

[24] The period analyzed, however, was 2010 so there were no virtual demand or supply bids in the day-ahead data used for these calculations. It would be appropriate to analyze some post virtual bidding 2011 day-ahead cases to test that there are no unexpected outcomes.

[25] One proposal that was discussed and, we understand, analyzed in the April 29 Department of Market Monitoring presentation was to impose ramp rates only on increments to generation, while allowing the candidate pivotal suppliers to lower output to zero. An argument in favor of this is that the ability to ramp up is a technical limitation while ramp down limits are more economic in nature (as generators can go off line quickly if necessary). However, we view this asymmetric treatment of ramp rates as undesirable, and likely to result in most or all congested constraints failing the 3-PS test in the HASP and RTPD competitive path analyses without regard to the actual competitiveness of the constraint. This is because the total 'demand' for counterflow (from large suppliers withdrawing supplies in the 3-PS test) is likely to be relatively large compared to the supply (due to the assumption that the supply of the top 3 suppliers would be reduced to zero without regard to their actual dispatch rates while the supply of counterflow would be limited by rampability). Whether this will indeed be the case depends on some of the details in how the approach is implemented and needs to be determined by simulation and experience, and we recommend that such studies be undertaken.

It is our understanding that the real-time results in the April 29 DMM presentation were based on assuming withdrawal of 100% of the counterflow provided by the top three suppliers compared to the 5 minute ramp capability of the competitive fringe. The MSC has not reviewed any of those results in detail to understand what the outcomes reflected in terms of the actual competitiveness of the constraints.

That said, the RSI measure implemented under the new approach, like the pivotal supplier measure of the current approach, is only a rough approximation of the true potential for the exercise of market power at any given moment. The goal of carrying out the competitive path analysis calculation closer to real-time allows the analysis to be based on more accurate assumptions regarding generation status, transmission outages, and load levels, but there is less time to carry out any such calculations than if the analysis were carried out six months in advance. However, it would be useful to assess the historic relationship between the true residual demand faced by firms – as measured by market bids from those and other firms – and the implied market power indicated by measures such as the pivotal supplier and RSI tests.

2.2.3. Assessment of Step 2 (CPA). This revision of the CPA methodology is potentially an important step forward. The previous methodology required extensive staff hours to implement and was performed on a quarterly basis for a small number of projected market conditions and a limited number of paths. Also, the proposed dynamic procedure has the potential to better target mitigation to the conditions in which the potential for the exercise of market power exists. Whether the design fully realizes that potential will depend on the performance of implementation details that are not yet fully specified. Therefore, we cannot express an opinion at this point in time regarding the desirability of implementing the particular form of the dynamic competitive path analysis that will be proposed by the ISO. As the details of the design are developed and tests are performed over the coming months, we anticipate being able to make an informed assessment of the particulars of the proposal.[26]

We support the proposed treatment of ramping constraints in the CPA. We recommend that no ramping constraints be imposed in the day-ahead CPA, which is what the ISO proposes. In the case of HASP and real-time, we are concerned that the ramp constraints used to define the supply available from the fringe should be related to the 'demand' for counterflow (amount of increased supply of counterflow needed) within the same time frame used to define the fringe's ramp constraints. The amount of counterflow 'demand' would be related to how much the potential pivotal suppliers could adjust the counterflow they supply. Therefore, we are generally supportive of the inclusion of 15 minute ramp limits in real-time for both the fringe and the potential pivotal suppliers, which we understand is to be part of the proposal.

However, before reaching conclusion concerning a particular design, it would be necessary to test off-line how the design performs on real data to understand the consequences of the various implementation choices.

It is also our understanding that the most recent ISO proposal for real-time CPA would involve symmetric treatment of ramp rates (downward rates limiting supply withdrawal by potential pivotal suppliers, with upward rates limiting additional supply from the fringe), which we prefer to the asymmetric proposal just discussed.

[26] For example, if simulations or experience were to show that mitigation would be triggered whenever any constraint (other than grandfathered constraints) binds in real-time, then it may be possible that the same result would be obtained by skipping the CPA process in real-time and basing mitigation just on swing factors with respect to binding constraints.

We have one suggestion for improving the current LMPM design, although the MSC as a whole is not unanimous on their desirability.

Our recommendation is to implement a financial constraint based upon day-ahead schedules upon withdrawal of capacity. The ISO CPA proposal states that the following constraints will be considered:

- transmission and generation resource availability (outages and derates),
- the effectiveness of a resource to relieve congestion on a constraint,
- ramping limitations of resources,
- operating reserve from resources that is not available for energy dispatch, and
- tolling agreements that involve bidding and operational control of a resource.

In addition, in the HASP and RTPD CPA analyses, we believe that it is appropriate to consider other readily verifiable constraints that limit the ability or incentive for producers to withdraw output. In particular, it is well-recognized that forward contracts greatly dampen the incentive to exercise market power in spot markets. This general principle applies here to day-ahead schedules in addition to tolling arrangements that are readily considered in the CPA.

Day-ahead scheduled generation changes the incentive of a producer to withdraw output in the real-time markets. If a generator is scheduled day-ahead to produce a certain amount, then if it chooses in real-time to generate less than that amount, it is on the hook financially. If it withdraws that capacity in order to increase its local price, it will have to make up for that energy by buying it in the market at the now higher local price. This eliminates the incentive for such a supplier to exercise market power by producing less than its scheduled amount day-ahead. Therefore, there is no reason to consider the possibility in a real-time CPA of a pivotal supplier reducing its output below its day-ahead schedule. This constraint may be less stringent or more stringent than, for instance, ramp-rate constraints, depending on the situation, and so needs to be considered explicitly.

It is of course possible for a generator who is scheduled day-ahead to purchase power in a bilateral contract that could benefit from an increase in price. In this way, a generator's financial disincentive to decrease generation below its day-ahead schedule could be weakened or eliminated. One way in which this concern could be addressed is by adding the qualification that the counterflow provided by a generator cleared in day-ahead, dispatched in RTPD, and, in addition, is offered in real-time at an offer price that is lower than or equal to the day-ahead price at its location will be included in the counterflow provided by the fringe.

Similar financial constraints on the actions of potentially pivotal suppliers were considered in the original use of the California ISO of the RSI in the analyses of system-wide market power conducted by DMM.[27] We note that consideration of these constraints would expand the proposed structural approach to LMPM to consider financial incentives in addition to technical supply ca-

[27]Such as netting out long term contractual or regulatory obligations; see A.Y. Sheffrin, J. Chen, and B.F. Hobbs, "Watching Watts to Prevent Abuse of Power," IEEE Power & Energy Magazine, 2(4), July/Aug. 2004, 58-65.

pability. However, the division between technical structure and financial incentives is not a clean one, as the ISO's proposed consideration of tolling arrangements can be viewed as one or the other. It is indisputable that day-ahead schedules provide very powerful incentives to not withdraw capacity, and if we desire to avoid over-mitigation, we see no obvious reason why such verifiable financial-based constraints should not be considered in the new CPA system.

In addition to the above recommendations for alterations in the proposal, we also have several suggestions for additional studies on the effectiveness of LMPM mechanisms, described in Section 6, below.

2.3 Step 3: Calculate Congestion Components

The next step in the local market power mitigation process is to decompose the congestion component of the LMP prices determined in the all-constraints run between competitive and non-competitive components based on the identification of binding non-competitive constraints in the Competitive Path Analysis step described above.

This step has two purposes. One is to calculate the non-competitive component, which is used in a subsequent step to determine which generators will be mitigated (Step 5, described in Section 2.5). The other is to derive a competitive constraints price for each generator that will be used as a floor on offer price mitigation (Step 4, Section 2.4), just as the price in the competitive constraints run is used to define the floor price for mitigation in the current local market power mitigation design. This can in principle be accomplished by setting the non-competitive congestion components of the LMP price determined in the all-constraints run to zero, so that the competitive constraints price is equal to the sum of the price at the reference bus, the cost of incremental losses relative to the reference bus, plus the competitive constraint congestion components. While the decomposition of the congestion component into competitive and non-competitive components is straightforward, there is one important practical complication. This is the dependence of this decomposition on the location selected as the reference bus. This topic is discussed in Section 3, below.

2.4 Step 4: Calculate Competitive Floor Price

Recall that the philosophy of this mitigation approach is to modify a market participant's offer prices only when those offers potentially reflect the exercise of market power. This concept is captured in the separation of transmission constraints into competitive and non-competitive constraints. However, absent the application of a competitive price floor, it is possible for the application of local market power mitigation based on default energy bids to dispatch a generator to an output greater than that required to relieve congestion on non-competitive constraints.

Under the proposed mitigation design, a generator offer price may be lowered ("mitigated") based on the generator's default energy bid (DEB) prior to the market run in either the day-ahead market, the HASP, RTPD or RTD. If all mitigated offers were to be reset to the DEB, the California ISO's dispatch software may want to take more supply from this generator than the amount needed to relieve non-competitive constraints. Thus, although an offer price of a generating unit may be lowered because that unit's output can relieve a non-competitive constraint, the output dispatched from the generator based on its DEB may be well beyond the output necessary to simply relieve that non-competitive constraint.

Such an outcome has been deemed inconsistent with the principles underlying the California ISO's mitigation design. Therefore in order to limit the mitigation to impacting generation output only to the extent necessary to solve non-competitive constraints, a floor is imposed on the mitigated offer prices of all affected units. In this case the floor is the "competitive" price that is determined in the all-constraints run and calculated by removing the non-competitive congestion component from the LMP. With this bid floor in place, the output of generators subjected to offer price mitigation will likely not be increased relative to their output in the unmitigated all-constraints run beyond the output needed to relieve binding and potentially non-competitive constraints.[28] There would arguably be no need for such a competitive price floor if the competitive offer price for each segment of each generator could be measured perfectly and reflected in the default energy bid, but this is not the case in practice. The default energy bid calculated by the DMM is only an approximation of the competitive offer price (marginal cost) and can be lower than the actual marginal cost (for instance because of within-day gas imbalance charges). If mitigation is applied to generators lacking market power and the DEB mismeasures marginal cost, then the application of mitigation could potentially reduce market efficiency by distorting prices and outputs. Mitigation to the maximum of the DEB and the competitive price (LMP minus the non-competitive component) lessens the risk of this outcome.

With the non-competitive congestion component for each LMP calculated, the next step will be to calculate the competitive constraint floor price for each generator by setting the non-competitive congestion component of the locational price at each generator's location to zero. For generators whose output does not relieve congestion on any non-competitive constraint, these non-competitive congestion components will be zero, if the reference bus is appropriately defined. Hence, the floor price used in the mitigation of generator offer prices will be the sum of the reference bus price, the loss component, and the congestion component (the sum of the product of the generator's swing factors and the competitive constraint shadow prices). It is also important to recognize that the congestion component used to calculate the competitive floor price will also be zero for any constraint that is not binding in the all-constraints run, even if that constraint becomes binding in the market run as a result of mitigation and the dispatching up the mitigated generator. If the latter occurs, then because the newly binding constraint was not binding in the all-constraints run, this constraint will not impact the competitive constraints price, nor will it impact the mitigation applied to resources impacting such a constraint.

[28] Mitigating a generator's bid to the competitive price must yield alternative optima to the scheduling problem, one or more of which would involve incrementing the generator beyond the level required to just relieve the constraint. For instance, if there was one constraint, with the system having price 20 $/MWh (equal to the marginal cost of some large generator) and a bidder in the load pocket having a MC of 10 $/MWh bidding 30 $/MWh instead, then mitigating that bid to 20 $/MWh will result in alternative optima (the mitigated unit could displace some of the large generator, going beyond what is needed to relieve the constraint). Only if the bid is permuted (say to the competitive price plus epsilon) would this be avoided for sure in this simple case.

A few consequences of the application of the competitive floor price deserve explicit comment. First, by imposing a mitigation price floor tied to the clearing price outside the constrained region to which mitigation is applied, the competitive floor price reduces the extent to which the application of mitigation based on an understated gas price will distort the economic dispatch. In particular, this avoids the dispatch units with high heat rates instead of units with lower heat rates due to understated gas prices. Second, however, such a floor price essentially eliminates offer price mitigation for generators within generation pockets who would be able to raise their offer prices to the level outside the generation pocket, even if the true competitive price level within the generation pocket would be lower. We are not aware of any Department of Market Monitoring analysis indicating that this second effect of the floor price has been material enough to warrant considering a more complex local market power mitigation design to accommodate gen pocket market power.

2.5 Step 5: Apply Mitigation

The final step in the local market power mitigation process will be to apply mitigation to generator offer prices by capping mitigated offer prices at the higher of the default energy bid or the competitive floor price at their location as calculated in Step 4. Mitigation will be applied to the offer of any generator having an overall positive congestion component on non-competitive constraints.

In the day-ahead market, HASP and RTPD runs, the entire unit commitment evaluation would be repeated utilizing the mitigated offer prices. The non-convexities in any unit commitment process give rise to the possibility the solution based on mitigated prices will result in slightly higher prices at some locations in some periods than in the original unmitigated solution, so it is possible that some units will be dispatched to a slightly higher output in the market run than in the all-constraints run as a result of such changes.[29] Nevertheless, these effects should be small, so as a broad principle, suppliers subjected to mitigation are likely to be dispatched above their output in the original all-constraints run only in order to relieve congestion on a non-competitive constraint. Whether this is indeed the case should be monitored by DMM.

This cannot be said of the real-time dispatch, because the competitive constraints price used to derive the competitive price floor for mitigation will have been calculated in a prior HASP or RTPD run which may have been based upon a different load forecast or system conditions than those prevailing in real-time. Hence, there is a potential for resources to be dispatched above their output in the initial all-constraints run, even if the relevant non-competitive constraint is not binding in real-time. This could be the case, for example, if load was higher in RTD than projected in RTPD, if there were a ramp constraint binding in RTD that was not present in RTPD, or as a result of other changes in system conditions. We were unable to identify a viable alternative that avoids this outcome; however, no resource would have its offer price reduced below its default energy bid.

[29] This is one reason that mitigation is only applied to resources with positive congestion components in the day-ahead market, HASP and RTPD runs.

There are several features of the way offer prices would be mitigated in the proposed design that warrant discussion. These are the treatment of irreversible unit commitment decisions in HASP and RTPD, the potential for a given unit's offer price to be mitigated in the day-ahead market and again in RTPD, and after the fact mitigation when RTPD does not solve or does not solve accurately.

Consider first the treatment of unit commitment decisions in HASP and RTPD. If mitigation is applied to resources in the HASP as a result of a binding non-competitive constraint, this will affect import scheduling and short-term unit commitment decisions, which will be made based on the mitigated offer prices. It is possible that changes in system conditions between the HASP and RTPD run could cause that non-competitive constraint to be non-binding in RTPD. In this situation, units that were committed based on mitigated offer prices in the HASP, would potentially not be subject to mitigation in real-time (RTD). This change gives rise to a potential inconsistency between the prices used to evaluate the unit commitment and those used to dispatch the system in real-time, in which a lower cost alternative might not have been committed in HASP because that evaluation was based on mitigated offer prices.

This concern is not primarily a concern regarding the exercise of market power but one of potential inefficiency in the unit commitment. Since the test of whether the potentially non-competitive constraint is binding in RTPD would be based on the unmitigated offer prices, it is not apparent how unmitigated offer prices that were materially higher than the default energy bids could fail to trigger a binding constraint and hence mitigation. Nevertheless, given the potential for situations that are difficult to foresee in the abstract, it would be reasonable for the Department of Market Monitoring to review instances in which resources are dispatched up or committed in HASP based on mitigated offers but not subject to mitigation in real-time so that any unintended outcomes from this mitigation design can be identified.

A second noteworthy feature of the mitigation design is that a given resource could be subjected to mitigation in the day-ahead market based on the competitive constraints price calculated in the day-ahead market and scheduled in the day-ahead market based on that offer price, then mitigated again in RTPD and dispatched in real-time based on a potentially lower competitive constraints price calculated in RTPD. While this feature of the mitigation design is noteworthy, there are no apparent adverse effects from this potential outcome, particularly since resources cleared in the day-ahead market will sell their output at day-ahead prices, so their economics would generally be unaffected by real-time offer price mitigation.

Third, a noteworthy element of the mitigation design is that if RTPD fails to run correctly and hence does not apply mitigation, mitigation will be applied after the fact to calculate prices based on correctly mitigated offer prices for use in settlements.[30] This is a different treatment than proposed for constraints that are binding in RTD but not in RTPD. The situations are different, because in the case in which RTPD fails to run, there is clear potential for offer prices that are substantially in excess of the default energy bids or competitive offer prices to be used to calcu-

[30] See California ISO, Department of Market Monitoring, "Draft Final Proposal – Dynamic Competitive Path Assessment, "May 23, 2011 pp. 7-8.

late settlement prices. We also understand that the frequency with which such price adjustments are expected to be applied is well below the 0.6% failure rate mentioned in the ISO draft proposal, because failure rates have been declining with experience, no constraint may be binding in the failed interval, and a binding constraint may nevertheless be determined to be competitive.[31] We therefore find this method of addressing RTPD execution failures to be reasonable.

3. Impact of the Reference Bus Location on Mitigation

The decomposition of the LMP price determined in the all-constraints run into the reference bus price, the loss component, the competitive constraint congestion component, and the non-competitive constraint congestion component depends on the location selected as the reference bus for the purpose of this decomposition. The overall LMP price is independent of the location of the reference bus, but the decomposition among the various components can vary substantially depending on this location. This dependence is important to understand in evaluating the proposed local market power mitigation process because the location of the reference bus can impact whether the non-competitive component at a particular location is positive or not as well as its size and, thus, the effectiveness of the market power mitigation.

In particular, if the price at the reference bus is impacted by the exercise of locational market power on any non-competitive constraint in the all-constraints run, then a "competitive constraint price" calculated relative to that reference bus by setting the non-competitive congestion component to zero will be inflated by that exercise of market power. What is meant by "impacted by" in this context is that the exercise of market power not only causes an increase in the congestion component associated with the relevant non-competitive constraint but also causes an increase in the reference bus price, because the price of power at the reference bus is increased by that exercise. In the extreme case, if the reference bus were located at the bus of a generator exercising locational market power, the non-competitive congestion component associated with that constraint would be zero and market power mitigation would be ineffective because the "competitive constraints price" at the location of the generator exercising that market power would be the same as the unmitigated price at that location in the all-constraints run.

Because the California ISO's market run uses a distributed load reference bus, the extreme outcome in which market power mitigation is completely ineffective would not occur if mitigation were based on this reference bus. But if a significant fraction of the load is located in load pockets where the exercise of local market power is possible, then that distributed bus' price could be raised by the exercise of locational market power, causing mitigation to be incomplete. That is, prices would not be mitigated down to the level that would have prevailed absent the exercise of the locational market power.

The California ISO has recognized this potential and has sought to avoid such an outcome by proposing to recalculate the reference bus price, loss component, competitive constraint congestion component and non-competitive constraint congestion component relative to reference locations other than the distributed load reference bus. This would likely be either the Midway bus

[31] Ibid., p. 7.

or the Vincent bus.[32] A key uncertainty regarding the implementation of the proposed local market mitigation process is whether the use of these reference bus locations will in practice completely avoid inflation of the reference bus price through the exercise of locational market power.

The California ISO has carried out a retrospective analysis of congestion in the day-ahead market during February and March 2011 and determined that use of the distributed load reference bus price to calculate the competitive constraints price would have inflated the competitive constraints price by an average of $1.42 per megawatt hour, relative to use of the Midway and Vincent buses as the reference bus.[33]

An indicator that the price at the reference bus may be inflated by the impact of congestion on a non-competitive constraint is that some locations on the transmission grid have negative congestion components relative to the reference bus on one or more non-competitive constraints. This is not a sufficient condition for the existence of reference bus inflation, because it can for example arise as a result of generation pocket located behind/within a non-competitive constraint, but it is a necessary condition.

Several market participants expressed concerns regarding situations in which the congestion components calculated relative to the reference bus are positive for some non-competitive constraints and negative for other non-competitive constraints.[34] There are two distinct situations in which some locations have negative congestion components relative to non-competitive constraints. One is the situation in which the reference bus has been inflated by congestion on non-competitive constraints, so will be addressed by ensuring that this inflation does not occur. The other is the situation in which there is a generation pocket located within/behind a non-competitive constraint, in which case calculation of the competitive constraint price by setting the congestion component on all non-competitive constraints to zero is appropriate whereas only setting the positive congestion components to zero could produce outcomes in which the competitive constraint price for that location is extremely low, or even substantially negative.[35]

The California ISO's analysis of the 57 days of congestion in early 2011 will be useful in assessing whether the use of the Midway and Vincent buses as reference buses for the calculation of the competitive constraint price will avoid inappropriate inflation of the competitive constraints price. Nevertheless, this analysis will cover a limited period, with limited congestion, and it is possible that this would not be the case in the future on days with difference congestion patterns or more extreme congestion patterns. Similarly, although there is no specific constraint that market participants have identified as potentially leading to such reference bus inflation, we cannot rule out the possibility that a constraint will become apparent as system conditions change in

[32] See California ISO, "Local Market Power Mitigation Enhancements, Draft Final Proposal," May 6, 2011, p. 11.

[33] See Lin Xu, California ISO Market Analysis and Development, "A Retrospective Analysis of Local Market Power Mitigation Enhancements," May 9, 2011, http://www.caiso.com/2b79/2b79e5c95b260.pdf, p. 7.

[34] See Jeff Nelson for Southern California Edison, April 1, 2011 and Bahaa Seireg for Pacific Gas and Electric, April 1, 2011.

[35] These possibilities are illustrated in the attached appendix.

the future. Hence, even if the analysis of 2011 data ultimately shows that the Midway and Vincent buses would have performed well as reference buses in this period, it would be appropriate for the California ISO to monitor congestion components and shift factors following implementation of the new local market power mitigation design so that any emerging tendency for reference bus price inflation can be identified.

4. PG&E Alternative Approach

PG&E proposed an alternative approach to defining the competitive constraints floor price in its May 23 comments.[36] Under this approach, following the competitive path analysis, the market software would redispatch the generation committed in the all-constraints run to meet load while only enforcing competitive constraints. The prices calculated in this step would define the competitive constraints floor price for the purpose of offer price mitigation.

This approach is closer in design to the way the competitive constraints floor price is calculated in the current design than is the California ISO's proposed approach. The approach suggested by PG&E should calculate a floor price that is no lower than the floor price calculated as proposed by the California ISO using a reference bus that is not impacted by congestion on non-competitive constraints. The approach suggested by PG&E would potentially define a more appropriate competitive constraints floor price in the circumstance in which the reference bus is impacted by congestion on non-competitive constraints.

On the other hand, the approach proposed by PG&E could also yield inflated competitive constraints floor prices if unmitigated generation offers are dispatched to meet load in the competitive constraints-only dispatch or if unmitigated generation offers cause high cost generation to be dispatched in that step.[37] Such an outcome is more likely if the amount of generation possessing locational market power and offering supply at high prices is large relative to the amount of low cost excess supply committed in the low price side of the non-competitive constraint.

The California ISO has carried out an evaluation of the performance of the competitive floor price proposed by PG&E to the proposed congestion component design using historical data. The comparison is not perfect because the historical data computing the competitive floor price the way PG&E recommends did not hold the unit commitment fixed as PG&E proposes. Nevertheless, that analysis found that the PG&E approach would generally lead to higher competitive floor prices than the congestion component approach. There were a few instances in which the

[36] "Pacific Gas and Electric's Comments on Local Market Power Mitigation (LMPM) Enhancements Draft Final Proposal and Retrospective Analysis," May 23, 2011.

[37] For instance, consider the simple situation in which there is just one binding transmission constraint (which is non-competitive), and it lies between the system and a load pocket. In the all-constraints run, just enough generation might be committed to meet the system-side load plus its exports to the load pocket, with a high offer price generator in the load pocket meeting the remaining load pocket demand. Then in a competitive constraints-only run, there might be insufficient committed system generation available to displace the output of the high offer price generator within the load pocket, so this high offer price generator could set the price for the entire system, inflating the competitive floor price. This would be the outcome even if the load pocket generator offered supply at a price far above its DEB.

PG&E approach appeared to result in a lower competitive floor price. The MSC, however, asked the California ISO to examine the 7 hours with the largest differences and check whether the unit commitment was the same. It is our understanding that the California ISO verified that in every one of these seven hours the unit commitment was in fact different. Hence, the historical data are consistent with our expectation that the PG&E approach will generally lead to a competitive floor price that is higher, and potentially inflated by the exercise of locational market power, relative to the congestion component approach proposed by the California ISO.[38] In view of the facts that (1) no historical evidence of a potential for reference bus price inflation has been identified with respect to the Midway and Vincent reference buses, (2) the PG&E approach can also lead to inflated competitive floor prices, we do not recommend this approach. However, our recommendation of the Midway and Vincent reference buses is subject to further verification that their use would not lead to consequential reference bus inflation.

5. Extent of Mitigation

The proposed local market power mitigation design has the potential to subject more resources to mitigation than does the current design because all resources providing counterflow on a non-competitive constraint would potentially be subjected to mitigation. In contrast, under the present local market power mitigation system, only resources dispatched upwards in the all-constraints run (relative to their schedule in the competitive constraints run) are mitigated. Under the current implementation of local market power mitigation, a resource can raise its offer far above its default energy bid and above the competitive constraints price without being subject to mitigation if there is some other unit that can be dispatched to manage the constraint in the all-constraints run.[39] Such a resource would not escape mitigation in the proposed design. While this is an increase in the application of mitigation to locational market power relative to the current design, there is no principled basis for excluding such a unit from mitigation if it possesses locational market power.

Hence, as indicated by Dr. Lin Xu's analysis for the California ISO of a sample of day-ahead market outcomes spanning February and March 2011, it is likely that the proposed design will generally mitigate the offer prices of more units impacting a given constraint than does the current design.[40] However, we believe that this mitigation will be appropriate if the competitive path analysis is accurate in identifying resources that possess locational market power. The broad extent of the offer price mitigation applied makes it important that the competitive path assessment correctly identify the potential for the exercise of locational market power.

Conversely, however, Dr. Xu's empirical analysis also showed that the proposed design would focus mitigation much more tightly on instances in which non-competitive constraints will ac-

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[38] See Lin Xu, California ISO Market Analysis and Development, "Addendum to the Retrospective Analysis of Local Market Power Mitigation Enhancements," June 23, 2011 pp. 8-9.

[39] See Harvey, Pope, and Hogan, op. cit.

[40] Lin Xu, California ISO Market Analysis and Development, "A Retrospective Analysis of Local Market Power Mitigation Enhancements," op. cit., pp. 4-6.

tually be binding in the day-ahead market than does the current design.[41] Hence, it is reasonable to expect that there will much less mitigation of resources when no non-competitive constraint is binding compared to the current design, which we also believe is appropriate.

Dr. Xu's illustrative retrospective analysis of the proposed design also showed that an average of 7.2 units per hour with congestion on non-competitive constraints would be subjected to mitigation in the day-ahead market over the period studied. The number of units that would actually have been impacted by mitigation in the day-ahead market when a non-competitive constraint was binding under the proposed local market power mitigation design would have been less than the 7.2 units subjected to offer price mitigation in the retrospective day-ahead market analysis. This is because some or perhaps many of these units would not be committed in any case, so the mitigation of the offer price would not impact their scheduled output.[42]

6. Conclusions

Overall, the California ISO's proposed changes to its local market power mitigation design and implementation are desirable from several standpoints. In addition to complying with FERC Orders, these modifications will:

- allow the local market power mitigation process to be applied to the demand and supply bid into the day-ahead market (including virtual transactions);
- eliminate the potential for anomalous outcomes arising from the current two pass approach (including application of mitigation in the day-ahead market when no non-competitive constraint is binding); and
- will potentially speed the mitigation process enough (by eliminating the need for separate competitive constraints and all-constraints runs) to allow other improvements to be implemented, including on-line competitive path analysis.

A key element of the design and implementation is the choice of the reference bus used to compute the "competitive price" floor on mitigation. Its performance needs to be monitored as there is a potential for this floor price to be inflated by the exercise of locational market power if an inappropriate location is used as the reference bus in computing this price. A second element of the design and implementation that should be monitored is the degree of difference between the RTD and RTPD prices within constrained regions in RTD that were not constrained in RTPD, and hence no competitive path analysis was applied.

The approach that the Department of Market Monitoring currently envisions for applying the competitive path assessment in the day-ahead market appears reasonable and appropriate. However, it would still be desirable to test the design on day-ahead cases after the implementation of virtual bidding for both competitive and non-competitive constraints to verify in detail that the approach will operate as intended

[41] Ibid.

[42] Most of the 7.2 units were off-line in day-ahead market.

Some elements of the approach that the Department of Market Monitoring would use to apply the competitive path assessment in real-time have changed materially relative to the design proposed in April. We agree that these changes will tend to improve the operation of the competitive path analysis. However we are uncertain of how well the approach is likely to perform and we are in agreement that the operation of the Department of Market Monitoring's revised design for implementing the three pivotal supplier test in real-time should be studied using actual real-time data so that there is a good understanding of how it will perform before implementation.

While the proposed design will likely mitigate the offer prices of more units than would the current design when non-competitive constraints are binding, this outcome is appropriate if the application of mitigation is reasonably well targeted to when non-competitive constraints are binding. Conversely, the proposed design will likely much less often mitigate offer prices when no non-competitive constraint is binding, which is also appropriate.

Below we suggest some areas for investigation that may provide information useful for making CPA and LMPM more precise and effective, lessening the risks of both over- and under-mitigation.

1. **Interaction of Day-Ahead and Real-Time LMPM Due to Consideration of Ramp Rates.** What is the implication of limiting potential competitive supply in real-time to reflect unit commitment and ramp rates? On the one hand, the residual demand curve *at that moment* is as constrained by these constraints as by transmission. On the other, this takes on flavor of mitigating a potentially transient market opportunity caused by a particular dispatch. This market power may disappear in short order when other units respond to high interval prices. Is there some circularity to imposing these restrictions in measuring CPA in real-time? A related question is concerns the effect of treatment of ramp constraints in the RTPD and HASP CPA upon designation of constraints.[43]

2. The Relationship of Residual Demand and RSI. It would be useful to assess the historic relationship between the true residual demand faced by firms – as measured by market bids from those and other firms – and the implied market power indicated by measures such as the pivotal supplier and RSI tests. Without such an empirical comparison, it is impossible to assess whether, and under what conditions, the RSI accurately indicates the market power of suppliers.[44]

3. Check for Exercise of Local Market Power. Structural tests claim to predict when suppliers have market power that can be profitably exercised. There has been testing of how well congestion is predicted in the first stage of the structural test, but congestion is not the main outcome of interest. Testing is also needed to determine how well structural tests predict profitable market

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[43] The 2010 Market Issues & Performance Annual Report by DMM performs RSI analyses of congested paths in the real-time market, and both the 2009 and 2010 reports performed analyses of congested day-ahead paths. The analyses described how often individual congested paths would have passed or failed three pivotal supplier RSI screens. This type of information, in addition to mitigation and price effects, would be very useful. The reported results bear out the need for further studies that consider a wide range of conditions, since the day-ahead 2009 and 2010 RSI outcomes were very different.

[44] See the earlier recommendations of the CAISO MSC on this issue in Wolak et al., op. cit.

power. Apparently very little is currently known about the answer to this crucial question. However, we may simply be unaware of such efforts.

Although it is difficult to prove that any specific offer, even if higher than the corresponding DEB, is an attempt to exercise market power, it might be less difficult to diagnose market power based on average behavior. This does not provide a method for actual mitigation, but some MSC members believe that it might provide a valuable check on the mitigation that is taking place and that is not taking place.[45]

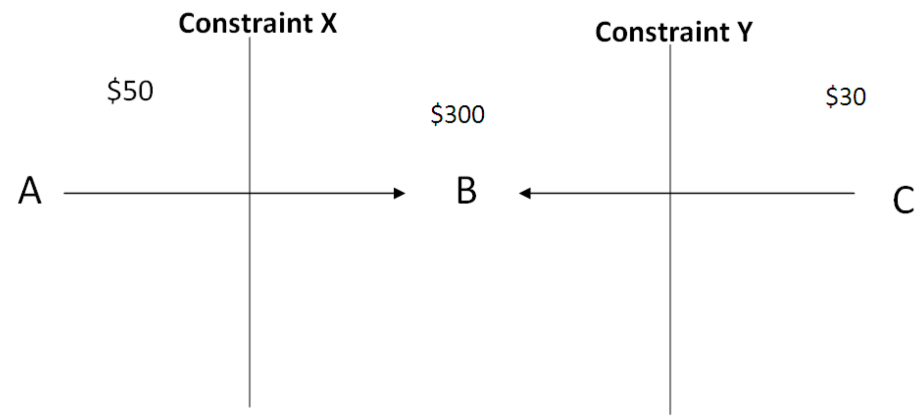
Appendix I
Off-Setting Congestion Component Examples

The first example illustrates the situation in which there are offsetting (positive and negative) congestion components at a bus located within a generation pocket that is in turn behind a non-competitive constraint. This situation is illustrated in Figure 3, in which both constraints X and Y are considered to be non-competitive constraints. Generation located at B is located behind constraint x and potentially possesses locational market power, while generation at C is constrained down because it is located within a generation pocket.

In this example the reference bus is located at A. The price at B is \$300. This \$300 price would be decomposed into a \$50 reference bus price, a \$250 congestion component price on constraint X and a 0 congestion component on constraint Y. The competitive constraint floor price for mitigation at B would be \$50, derived by setting the setting the congestion component for the non-competitive constraint X to zero.

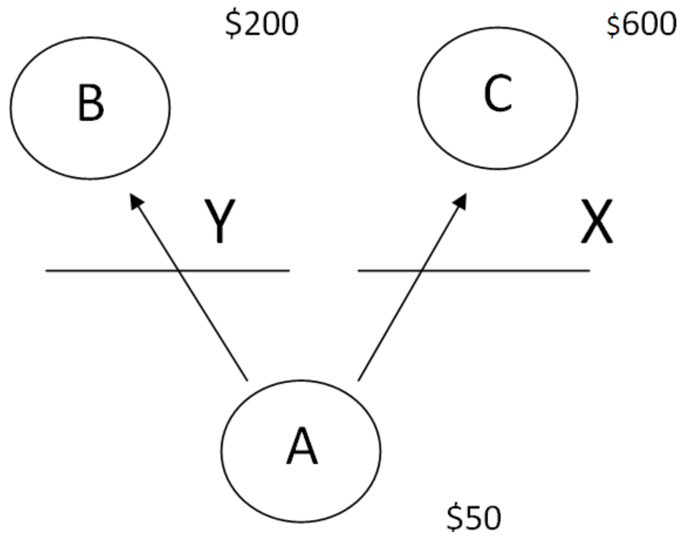
[45] One basic approach to looking for offers designed to exercise market power is to look for a correlation between offers and demand conditions and between offers and transmission conditions or generation outages. Offers should only exceed DEBs if marginal costs are above DEBs. While there is a small possibility that increased load will raise the price of gas and that this increase will not be reflected in a DEB, that bias could easily be corrected. Except for that, it is difficult to see why increased load or a generator outage should affect the marginal cost of on-line generators. A correlation between relatively high offers and increased load or congestion may indicate an attempt to exercise market power. However, such a correlation would be most informative if the same correlation did not exist in the offers of firms lacking locational market power.

Figure 3
Generation Pocket



The price at C on the other hand would be $30. This price would be decomposed into a $50 reference bus price, a $250 congestion component on constraint X (generation at C has the same shift factor on constraint X as does generation at B if the reference bus is located at A), and a -$270 congestion component on constraint Y. Under the California ISO's methodology for deriving the competitive constraint floor price, the congestion components for both constraints X and Y would be set to zero and the competitive constraint floor price would be $50. If on the other hand, if as has been suggested only the positive congestion components were set to zero, the competitive constraint floor price at C would be -$220, clearly not an appropriate outcome. Figure 3 on the other hand, illustrates a case in which offsetting congestion components reflect a reference bus that is impacted by the exercise of market power. Both constraints X and Y are non-competitive constraints in this example and the reference bus is assumed to be located at B.

Figure 4
Reference Bus Inflation



The $600 price at C would be decomposed into a $200 reference bus price, a -$150 congestion component on constraint Y and a $550 congestion component on constraint X. The fundamental problem is that the reference bus price at B is itself potentially impacted by the exercise of market power. While setting only the positive congestion components equal to zero would lead to an appropriate outcome at location C in this example ($50), this would not be case at other locations. For example, at B the LMP price would be $200 and all of the congestion components would be zero, so the competitive constraint floor price would be $200 under a rule setting only positive congestion components on non-competitive constraints to zero.