California Independent
System Operator Corporation

January 16, 2009

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

Re: California Independent System Operator Corporation
Docket No. ER06-615-___
MRTU Readiness Certification

Dear Secretary Bose:

Pursuant to Paragraph 1414 of the Order issued by the Federal Energy Regulatory Commission ("Commission") in the above-referenced proceeding on September 21, 2006,[1] the California Independent System Operator Corporation ("ISO" or "CAISO") submits this informational filing certifying the readiness of the ISO's Market Redesign and Technology Upgrade ("MRTU")[2] to go into effect on March 31, 2009.[3] As part of this filing, the ISO includes declarations by the ISO President and Chief Executive Officer, ISO senior management responsible for MRTU development and implementation, the Director of the ISO's Department of Market Monitoring, and independent consultants retained by the ISO as part of the readiness and implementation effort. All establish that MRTU will be ready for implementation effective as of March 31 provided that certain essential milestones and assumptions described below are satisfied. These declarations, taken together with the additional supporting information discussed in this filing, demonstrate the ISO's readiness to implement MRTU in compliance with the September 21 Order.[4]

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[1] *California Independent System Operator Corp.*, 116 FERC ¶ 61,274 (2006) ("September 21 Order").

[2] Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definitions Supplement, Appendix A to the CAISO Tariff (also referred to as the MRTU Tariff).

[3] The March 31, 2009 effective date applies to the Day-Ahead Market for Trading Day April 1. April 1, 2009 will be the first date the MRTU Real-Time Market is implemented.

[4] Pursuant to the notice of extension of time the Commission issued in this proceeding on January 5, 2009, this filing also serves as the monthly MRTU status report for January 2009 that the ISO is required to file in accordance with Paragraph 1415 of the September 21 Order. *See also* Section II, below (discussing monthly MRTU status reports).

I. Executive Summary

MRTU is the product of more than eight years of study, analysis, stakeholder input, coordination with state authorities, and Commission guidance to introduce a new structure for ISO electricity markets that support reliable operation of the California grid. The thorough preparation of both the ISO and Market Participants is documented in this filing, all of which substantiates that MRTU is on track for a successful implementation on March 31, 2009 (for an initial trade date of April 1), as long as important milestones are met.

The ISO is collaborating closely with Market Participants to prepare for MRTU implementation and to ensure that systems, processes, procedures, and individuals are ready for MRTU implementation. As a result of these joint efforts, potential impediments to MRTU implementation have been resolved or on track for resolution prior to the March 31 *go-live* date.

The ISO level of confidence regarding MRTU readiness is strong because of the vast amount of preparation completed by both the ISO and Market Participants. Working together, we have tested the new systems extensively, identified and resolved thousands of issues and variances, conducted thorough readiness audits both internally and externally, confirmed MRTU design and operations via three third party certifications, and have in place systematic plans to facilitate a successful cutover to the new market design and address possible contingencies. The ISO respects that Market Participants still have questions, especially with regard to the quality of solutions and settlement matters. The ISO will continue to work with them to ensure that these matters are adequately addressed. ISO management has also engaged in several discussions with other Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") to gain from their experience with similar market launches.

The ISO conducted more than 18 months of continuous MRTU market simulation – investing significantly more time than other ISOs/RTOs in testing, market simulation, and planning activities designed to culminate in a successful implementation of the new market design. The simulation confirmed system functionality and connectivity by identifying issues and software variances in advance of implementation. In the last year and a half the ISO responded to more than 3,250 issues reported by Market Participants in an effort to refine MRTU systems and operations. Today, the number of MRTU issues being received from Market Participants – 10-12 per day – is about equal to the number reported today during routine operation under the current market.

Having achieved all the benefits possible from market simulation, the ISO transitioned to parallel operation testing earlier this month. This period of MRTU simulation allows the ISO and Market Participants to mirror the daily operational conditions experienced in the current ISO control room. The ISO plans to move into pre-production on March 1 and will initiate cutover activities in mid-March to facilitate a smooth changeover to MRTU systems.

Internal MRTU activities are now chiefly centered on Grid Operations readiness. Within the last year, grid operators have completed multiple levels of training and are now concentrating on hands-on work with generation, transmission, and scheduling processes. Grid operators are managing the day-to-day operation of MRTU systems for MRTU parallel operations and interacting with Market Participants and resources in much the same way they will post MRTU launch.

In recent months, ISO and Market Participant readiness efforts have concentrated on five areas: quality of price solutions generated by the MRTU market software; market settlements; stability of MRTU software systems; and readiness of ISO Grid Operations and Department of Market Monitoring. Each of these areas of focus is discussed in detail below.

While the bulk of MRTU issues are resolved or will be addressed before program launch, some Market Participant concerns remain. The ISO understands the issues are important and plans to continue to collaborate closely with Market Participants to address issues as fully as possible prior to *go-live*.

The ISO is complying with all Commission directives specifically aimed at ensuring MRTU is ready for implementation. Based on the substantial preparations described herein, the ISO President and Chief Executive Officer, ISO senior management responsible for MRTU implementation, and the Director of the Department of Market Monitoring have signed declarations stating that MRTU is ready for implementation on March 31, subject to the essential milestones and assumptions set forth below. In addition, independent consultants retained by the ISO also provided supporting declarations in areas of their expertise and personal knowledge. These declarations are provided as attachments to this filing.

In the final weeks leading up to MRTU implementation, there will be several opportunities to assess progress. The ISO will continue to update the Commission and others with monthly MRTU status reports. In addition, the ISO Governing Board will review the organization's progress towards implementation at meetings scheduled in February and March.

The Commission's orders have recognized the significant benefits MRTU brings to California consumers. Successful implementation of the new market design and upgraded software systems is now within sight. The ISO assessment, at this time, is that none of the current open issues are material and none poses an impediment to a successful launch. Provided that the essential milestones and assumptions described in this filing are attained in a timely manner, the ISO will be able to implement MRTU on March 31, 2009. Finally, if for any reason the ISO determines that it is unable to launch MRTU on March 31, it will immediately inform the Commission and Market Participants.

II. Background and Overview of MRTU Readiness Process

The extensive history leading to the development of the MRTU initiative is detailed in several previous MRTU filings. In particular, the ISO's February 9, 2006 and August 3, 2007 MRTU tariff filings in the above-referenced proceeding provide comprehensive information that is not repeated in this filing. This filing is focused on the Commission's directives in the September 21 Order conditionally approving the MRTU Tariff to develop readiness criteria with stakeholder input and to submit an informational filing at least sixty days prior to the implementation of MRTU certifying market readiness.[5]

The ISO conducted its MRTU readiness process in accordance with the requirements of the September 21 Order. Since October 2006, the ISO has filed and continues to file monthly status reports with the Commission that include MRTU readiness updates. As explained in the monthly status reports, the ISO has developed measurable readiness criteria through a collaborative process, identified mitigation actions for non-performance or failure to meet readiness criteria, established a methodology to determine if ISO Scheduling Coordinators and Market Participants are prepared for MRTU implementation, and developed an MRTU readiness tracking system tied to specified milestones in the MRTU program timeline. Subsequent to the issuance of the September 21 Order, the Commission provided further direction to the ISO regarding the conduct of the MRTU readiness process,[6] and the ISO has also developed its MRTU readiness activities incorporating those directives.[7]

The ISO, in collaboration with stakeholders, developed a total of 33 MRTU readiness criteria. These 33 readiness criteria, the specific tasks that must be completed in order for the criteria to be met, and the completion status of those tasks are shown in color-coded tabular format in a document called the MRTU Readiness Criteria Dashboard, which the ISO has produced, filed monthly with the Commission, and made available on its website each month since January 2007.[8]

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5 September 21 Order at PP 1414-1415.

6 *See California Independent System Operator Corp.*, 119 FERC ¶ 61,076, at PP 188, 202, 230, 246, 286, 670 (2007) ("April 20 Order"); *California Independent System Operator Corp.*, 119 FERC ¶ 61,313, at P 450 (2007) ("June 25 Order").

7 Documents relating to the ISO's MRTU readiness activities are available on the ISO website at http://www.caiso.com/18ae/18ae96b71f1a0.html. Electronic links to the ISO website pages containing these and other MRTU-related documents are provided on the main page of the ISO website dedicated to MRTU matters, http://www.caiso.com/docs/2001/12/21/2001122108490719681.html.

8 The monthly MRTU Readiness Criteria Dashboard documents are available on the ISO website at http://www.caiso.com/18d0/18d0e11f139b0.html.

In its monthly status reports to the Commission, the ISO has included a description of the current state of MRTU readiness as reflected in the most recent MRTU Readiness Criteria Dashboard as of the date of each report. The ISO's most recent monthly status report, filed on December 8, 2008, contains a thorough discussion of the status of MRTU readiness and will not be repeated here.[9] This certification letter provides additional information including an updated MRTU Readiness Criteria Dashboard, dated January 16, 2009, which is provided as Attachment 8 to this filing. This updated dashboard shows that all MRTU readiness criteria have a status of either Blue or Purple (*i.e.,* are on track or complete).[10] The four criteria that were Orange in the dashboard attached to the December 8, 2008 MRTU status report (STL-2, STL-3, PRT-1, and ORG-3) are discussed in detail below in Sections III.B, III.E, and V.B. An additional criterion with Blue status as of the December 8, 2008 MRTU status report – the exit criteria for the Market Simulation Update 2 – tracked as SIM-1.4.3, a sub-criterion of SIM-1, is discussed in Section III.C below. The ISO expects to complete all readiness criteria that are on track (Purple status) between the date of this filing and *go-live*.[11]

The input of stakeholders was critically important to the ISO in developing the MRTU readiness criteria and remains important in assessing the status of the ISO and Market Participants in satisfying those criteria, and in the development and implementation of MRTU itself. The ISO and stakeholders engaged in numerous discussions with the goal of ensuring that MRTU will be a success. The ISO expresses its gratitude to stakeholders for their remarkable efforts and in particular for their input concerning ISO readiness activities.

On December 16, 2008, ISO management presented to the ISO Governing Board ("Board") a briefing on MRTU that included discussion of the

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[9] The December 8, 2008 MRTU status report is available on the ISO website at http://www.caiso.com/2098/209877992f6e0.pdf.

[10] As explained in the MRTU Readiness Criteria Dashboard, the status of each MRTU readiness criterion is indicated by the following color codes: (1) Clear: A Readiness Criterion is clear (C) if the Readiness Criterion has not begun; (2) Purple: A Readiness Criterion is purple (P) if the completion or status updates are on schedule based on the specified target due date or milestone, OR a mitigating action has been implemented successfully and the Readiness Criterion is back on schedule to be completed on the specified target due date; (3) Orange: A Readiness Criterion is orange (O) if one or more Readiness Components in that Readiness Criterion are not complete on the specified target due date or milestone, OR a Readiness Criteria has reported risks or issues that have a potential for not allowing it to be completed on the specified target due dates or milestones; and (4) Blue: A Readiness Criterion is blue (B) if all Readiness Components in that category are complete.

[11] For example, two criteria have targeted completion dates of thirty days prior to *go-live*, three criteria are targeted for completion by the entry of pre-production, five criteria are targeted for completion by the exit of pre-production, and two criteria have targeted completion dates of one day prior to *go-live.* In addition, some tasks in the criteria have not begun because of the timing of the tasks. As used in the instant filing and in various materials related to MRTU, the term "production" describes activities that take place after MRTU *go-live*, as compared with the term "pre-production," which describes activities that take place in preparation for *go-live*.

progress toward achieving MRTU *go-live* and remaining readiness issues. The Board unanimously issued a resolution that included the following statements:

- ISO management and stakeholders reported that significant progress on MRTU readiness had been made since the Board's previous (November 24, 2008) meeting.

- Assuming that progress on certain essential items continues as expected, ISO management and stakeholders reported that a March 31, 2009, MRTU *go-live* date is achievable.

- ISO management is committed to making every effort to implement MRTU on March 31, 2009, and the stakeholders share that commitment.

- The Board directs ISO management to file a readiness certification with the Commission, no later than January 16, 2009, for a March 31 *go-live* date that identifies the milestones and assumptions that are essential for that *go-live* date.

- The Board will continue to monitor progress toward a March 31 *go-live* date at its scheduled meetings.[12]

III. Current State of Readiness

The ISO, with invaluable input from Market Participants, has substantially resolved the large majority of issues regarding the timely implementation of MRTU, and any remaining issues are on track to be resolved or otherwise addressed prior to March 31, 2009. The ISO and Market Participants agree that MRTU implementation depends on substantial resolution of concerns that fall into five general categories, which are discussed below.[13]

A. Quality of Price Solutions

After 18 months of market simulation, the ISO is confident that the MRTU software is producing correct prices. As discussed below, the ISO has addressed pricing anomalies caused by software variances that were observed in market simulation. In addition, the ISO has tools in place to validate and correct prices and has asked for additional authority from the Commission to cap prices to mitigate the risk of correctly produced but unreasonably high prices. The ISO has also requested Commission authority to run the validation and correction process prior to publication to ensure that no incorrect prices are published.

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[12] This Board resolution is provided in Attachment 1 to this filing.

[13] Further discussion regarding the ISO's resolution of potential challenges to a successful MRTU implementation is provided in the ISO's December 8, 2008 MRTU status report.

1. Validation of MRTU Software

The ISO conducted analysis track testing to validate the software-produced solutions consistent with the rules prescribed the MRTU Tariff. The ISO retained the global consulting firm LECG to review the results of the ISO's analysis track testing of its dispatch and pricing software and to assess a series of cases used to test particular features of the software and whether it operated correctly under certain conditions. LECG issued a preliminary report dated April 16, 2008 ("LECG Preliminary Report"), in which it stated that there was no indication of substantial unresolved problems that would prevent the ISO software systems from calculating prices consistent with the MRTU tariff and the Locational Marginal Price ("LMP") methodology used under MRTU. The LECG Preliminary Report listed a number of minor issues with price calculation and dispatch optimality that appeared to be related to rounding differences and modeling issues. After the LECG Preliminary Report was issued, the ISO applied a series of patches to the MRTU software that fixed these minor issues.

LECG issued a final report dated October 20, 2008 ("LECG Final Report"), that certified that the MRTU software calculated Day-Ahead and Real-Time LMPs consistent with the MRTU Tariff. The LECG Final Report includes the following conclusion:

> Based on the analyses we have performed, we have not observed substantial unresolved problems that would prevent the CAISO software systems from calculating prices consistent with the CAISO tariff and LMP pricing methodology and have not observed material unresolved problems that would prevent the software systems from committing and dispatching load and generation based on least bid cost. Our review of the class B cases found that the features of the CAISO software being tested in these cases performed as intended in each instance.[14]

Moreover, during the October 28-29, 2008, meeting of the Board, Dr. Scott M. Harvey of LECG reported that the MRTU software functions as well as or better than market software implemented by other ISOs and RTOs implementing LMP-based markets at a similar stage in their preparation for launching LMP-based markets. In addition, the ISO's Department of Market Monitoring ("DMM") published a report on the prices produced for the September 2008 testing

[14] LECG Final Report at 2. The "class B cases" referred to in the LECG Final Report are a series of cases, in addition to the cases involved in the analysis track testing, that the ISO used to test whether particular features of the MRTU software operated correctly, or to test whether the software operated correctly during certain kinds of conditions. *Id.* at 1-2. The LECG Preliminary and Final Reports are available on the ISO website at http://www.caiso.com/1fc5/1fc5d12b5460.html. The LECG Final Report was also provided as Attachment 8.4 to the ISO's December 8, 2008, MRTU status report.

month[15] and, as discussed below, the DMM has published an additional analysis of MRTU pricing indicating that the MRTU software is functioning adequately for *go-live*.[16]

2. Explanation of Anomalous Prices in Market Simulation

Market simulation was an extremely valuable exercise to the ISO and participants for purposes of testing the new software and readiness for MRTU implementation. Under certain conditions, the software testing revealed anomalous prices. Where software problems have been identified, the ISO fixed and extensively tested the software. As noted above, this effort includes extensive analyses by both LECG and the ISO's DMM.

In addition to software issues, another factor affecting prices is the parameters in the software used to set price constraints in order to honor scheduling priorities. Depending on how the parameters are set, they can affect market prices and contribute to anomalous prices. The ISO conducted an analysis of how these parameters affect prices and revised the parameters to minimize their adverse impact on pricing.[17] The parameters for *go-live* are now set and are less likely to contribute to anomalous pricing.

There are other factors that contribute to the creation of anomalous prices in market simulation. With regard to scenario testing, during September 2008 and a portion of October 2008, the ISO executed specific scenarios requested by Market Participants. First, these scenarios were designed to test extreme conditions to allow the ISO to ensure the software worked appropriately under all conditions, not to represent real-world operations. Unusual and unanticipated conditions can create extreme, but correctly calculated, prices that would rarely if ever materialize in real-world operations. Second, the bids submitted by Scheduling Coordinators in the market simulation are not the same bids that would be submitted in actual MRTU operations reflecting real-world conditions. In submitting these bids, the Scheduling Coordinators are often only exploring how bidding would work in different operational conditions and are testing bidding strategies that are not expected to be utilized in actual operations. Thus, bidding behavior coupled with extreme scenarios is another reason for extreme prices.

To test the extent to which extreme prices are associated with extreme conditions – either extreme scenarios or bidding behavior that would not be

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[15] This DMM report is available on the ISO's website at http://www.caiso.com/2068/2068ad206a9b0.pdf.

[16] The DMM pricing report explaining the results of the ISO's Real-Time structured operational pricing test is provided as Attachment 9 hereto. In addition, the ISO has posted on its website material that summarizes the results of DMM's testing and discusses some details of prices. *See* http://www.caiso.com/209f/209f7bfe1dd20.pdf; http://www.caiso.com/20a6/20a67f452b390.pdf; http://www.caiso.com/232e/232e7dae6fd00.pdf.

[17] The tariff amendment to revise the parameters was filed on November 4, 2008 and is pending in Docket No. ER09-240.

anticipated to occur once MRTU is implemented – the ISO's MRTU program team, in consultation with the DMM, developed and performed a structured operational pricing test, based on relatively normal conditions, for the Day-Ahead and Real-Time Markets in October and December 2008. The test objectives were to investigate market performance in the following areas: the extent and root cause of anomalous positive and negative LMPs; price differentials at Load Aggregation Points ("LAPs"); evaluation of Residual Unit Commitment ("RUC") outcomes; and price convergence and explainable differences between the sequential markets under MRTU (*i.e.*, the Day-Ahead Market, Hour-Ahead Scheduling Process ("HASP"), and Real-Time Market). In summary, the test results were as follows:

- Most lingering concerns about market performance in the areas listed above were resolved.
- Day-Ahead Market results reflected accurate and stable prices, as was the case when the ISO conducted previous Day-Ahead testing in October 2008.
- There was convergence between hourly Real-Time prices and Day-Ahead prices.
- Price spikes were generally limited to peak hours, as expected.
- Price volatility was diminished and explainable.

To provide an in-depth assessment of results, the DMM issued a report detailing its analysis.[18] Based on this follow-up analysis, the DMM concluded that the MRTU markets performed reasonably well overall in the structured market simulations performed in December 2008 and that the DMM has not seen any performance issues that would warrant a delay in MRTU implementation. The DMM report urges the ISO to work with the DMM and Market Participants over the next six weeks to conduct a more in-depth assessment of some of the more extreme pricing outcomes in the December structured simulations to better explain and confirm the root cause of these results. The ISO agrees and will devote the necessary resources to review these extreme pricing outcomes during the weeks prior to *go-live* and will take any necessary corrective action.

3. Tools for Managing Anomalous Prices

The ISO is aware that some stakeholders continue to express concerns about high prices occurring during MRTU market simulation, including specific concerns about high prices for RUC Awards. High prices are not anomalous *per se*. Some high prices are consistent with the more accurate pricing of

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[18] See Attachment 9 to this filing. This DMM report is also available on the ISO website at http://www.caiso.com/docs/2005/10/04/2005100412253314368.html.

transmission congestion under MRTU and should not be considered as incorrect or anomalous. Indeed, LMP is intended to send strong transparent signals concerning the cost of energy and transmission congestion to influence scheduling and bidding behavior. Therefore, high nodal prices in a given location under the MRTU design reveal congestion costs that are masked under the current ISO zonal market design, which incorporates such costs in a zonal price paid by both suppliers and consumers.

Nevertheless, the ISO also recognizes that it is prudent to implement additional measures to mitigate the potential adverse consequences of possible anomalous extreme prices once MRTU is implemented. To supplement the existing price validation and correction provisions set forth in Section 35 of the MRTU Tariff, the ISO filed a tariff amendment in November 2008 that proposes a price cap of $2,500/MWh and a price floor of minus $2,500/MWh on the LMPs, RUC prices, and Ancillary Service marginal prices in all of the MRTU markets. As the ISO explained in its filing, the price floor and price cap will act as a “safety cap” to prevent potentially severe settlement impacts of anomalous prices for Energy, RUC, and Ancillary Services that could result from unanticipated and unusual circumstances as the ISO transitions to MRTU.[19]

Further, in response to comments submitted in that same MRTU Tariff amendment proceeding, the ISO has proposed to delay the publication of any anomalous prices that will be revised, or stand a reasonably significant chance of, being revised (whether under existing price correction provisions of the tariff or under the proposed price cap), until such prices can be verified and corrected, if appropriate, pursuant to the ISO’s validation and correction authority.[20] The Commission has not yet acted on this proposed tariff amendment, but approval of the publication proposals contained therein will allow the ISO to prevent extreme incorrect prices from being posted prior to the ISO conducting its validation and correction process and will prevent prices above or below the caps from being settled even if the prices are found to be correctly produced in accordance with the MRTU software.[21]

The ISO will be monitoring prices generally and will consider appropriate action in the event the MRTU software is producing correct but anomalous prices. For example, the ISO is aware of concerns expressed by several Market Participants about RUC prices. The ISO and the DMM have tested and analyzed RUC results and have concluded that the software is performing in accordance with the tariff. The ISO understands Market Participants’ concerns and has

[19] *See* Transmittal Letter for MRTU Tariff Amendment to Adopt Price Cap and Floor, Docket No. ER09-241-000 (Nov. 3, 2008), at 1.

[20] As currently filed, the MTRU Tariff provides for the posting of initial prices and the reposting of corrected pricing within eight days. The pending proposal would allow the ISO to defer posting prices until after the validation and correction process is run.

[21] The Commission accepted the price correction and validation provisions currently contained in the MRTU Tariff in *California Independent System Operator Corporation*, 123 FERC ¶ 61,285, at Ordering Paragraph (A) (2008).

committed to exercise all available tools to address any RUC market performance issues that arise after *go-live*. The ISO will continue discussions with all Market Participants about RUC market design and after *go-live* will consider changes as informed by market performance and those discussions.

The ISO's Rapid Response Team, discussed below, will be in place to act quickly utilizing available tools, including tariff waivers and expedited tariff amendment filings, to fix any market design flaws, including any flaws associated with the RUC design, that become apparent under actual operations. In addition, the ISO has authority to revise the parameter settings either through a tariff amendment or, for those parameters that are not in the tariff, through the Business Practice Manual ("BPM") change management process. The ISO underscores that market simulation, while extremely valuable to help identify software and other problems that require fixes, produced prices that should not be deemed indicative of prices produced under actual market operations. Accordingly, the ISO believes that concerns about quality of solution and high prices have been addressed and present no impediment to MRTU implementation.

B. Settlements

The ISO has validated all the MRTU Charge Codes necessary for *go-live* and is producing accurate prices on settlement statements, thereby allowing Market Participants to validate the Charge Codes. This is an important outcome of market simulation. In parallel, Market Participants are working on shadow settlement systems that in part require data from ISO's systems. The system interface and the readiness of those shadow systems are also important components of overall settlement readiness.

1. Production and Validation of Settlement Statements

With respect to the production of accurate settlement statements, the ISO has made substantial progress and has incorporated and validated the final Charge Codes necessary for *go-live*. The ISO is now taking a number of actions to ensure that it will be able to implement its full settlement process at MRTU *go-live* and to enable Market Participants to understand settlement statements produced by the MRTU systems and to validate their systems.

To assist Market Participants to develop and validate their systems, the ISO has taken the following steps:

- Increased data traceability from bid to bill, enabling Market Participants to correlate bid amounts and market awards with settlement data outcomes.

- Accelerated implementation of monitoring and data recovery effort. All payloads and missing data are reviewed on a daily basis to ensure that the correct data is timely passed to downstream applications.

- Created a Quality Assurance Team tasked with completing a thorough review of all settlement statements in order to ensure each settlement statement is complete and accurate prior to publication. The procedures developed by this team are now implemented and have been turned over to the ISO business units to continue and incorporate into their business processes.

- Provided individualized attention to Market Participants to answer any questions and to ensure that ISO systems and Market Participant systems are using settlement data correctly and consistently.

These steps have already resulted in great improvements in the issuance of correct settlement statements since the beginning of November 2008. In addition, the ISO implemented the issuance of daily Market Notices that provide Market Participants with a summary of any missing data or Charge Codes that are not working properly, the reasons for those issues, and the target resolution dates. The major settlement issues raised by Market Participants are now addressed and, by doing so, the ISO anticipates that the number of valid disputes following *go-live* will be manageable.

The ISO notes that, in the MRTU Readiness Criteria Dashboard attached to the December 8, 2008 MRTU status report, an Orange status was assigned to readiness criterion STL-2, which requires the ISO to test and implement its final Settlement Charge Code configuration, and to readiness criterion STL-3, which requires the ISO to publish accurate and complete settlement statements and invoices during the final phase of market simulation. Because the ISO has taken the steps described above, the Orange status assigned to these reliability criteria was changed to Purple as indicated in the MRTU Readiness Criteria Dashboard attached to the instant filing.[22]

Finally, in accordance with Section 11.29.5.4 of the MRTU Tariff, the ISO engaged PricewaterhouseCoopers ("PwC") to provide an audit opinion confirming whether the Settlements and Market Clearing ("SaMC") software calculates quantities and prices in compliance with the Tariff. PwC is working with ISO staff and is on track to issue, prior to the close of the first Day-Ahead Market on the MRTU *go-live* date, its certified audit opinion regarding the SaMC software. The ISO will issue a Market Notice with PwC's certified audit opinion after it is released and will provide a copy of this Market Notice to the Commission.

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[22] *See* January 16, 2009, MRTU Readiness Criteria Dashboard, provided as Attachment 8 to this filing.

2. High Charges Reflected on Settlement Statements

Some Market Participants received settlement statements coming out of market simulation that reflected extremely high charges – charges well in excess of charges seen on settlement statements and invoices in the current market. The ISO investigated such occurrences and found each to be explainable by one or more factors attributable to the market simulation environment. In order for settlement statements produced in market simulation to reflect accurately anticipated market outcomes once MRTU is implemented, a Scheduling Coordinator must have fully participated in the market simulation. If key data is missing, for example generation meter data, a Scheduling Coordinator could receive a statement and be charged for 100 percent of its demand. In fact, in market simulation, the ISO has found that most Scheduling Coordinators are not submitting meter data for use in the simulation. While the ISO generates some data for each Scheduling Coordinator based on the Day-Ahead Schedules and awards, if a Scheduling Coordinator changes its market strategy in the HASP or Real-Time Market, the meter data deviation could be significant and could therefore result in large deviations and Uninstructed Imbalance Energy charges. The ISO would not expect these problems to occur once MRTU is implemented as meter data is received directly from all ISO Metered Entities and from Load on the Trading Day plus 45 calendar days. The ISO strongly believes that the net charges reflected on a Scheduling Coordinator's settlement statement should not, in general, be materially different under MRTU as compared to today's market.

Another factor is Market Participant bidding behavior. Not all Market Participants participate or participate fully in the bidding and scheduling of their resources. In addition, the scenario testing includes deliberate underscheduling of both demand and supply that deliberately created large deviation charges in order to test the functionality. These high charges do not mean that MRTU is not working correctly. Given the nature of market simulation, however, the ISO believes it is not reasonable for Market Participants to expect settlement statements that would realistically reflect actual market operations.

The ISO has provided these explanations but recognizes that Market Participants continue to have concerns that they will be charged unreasonably large amounts under MRTU operations. The ISO also continues to reach out to Market Participants to discuss how certain market simulation practices have led to these extreme settlement results so that these lessons can aid them in their own readiness efforts to avoid such outcomes after *go-live*. To help address these concerns further, the ISO is also prepared to put in place a monitoring process to assess, well in advance of any charges appearing on a settlement statement, whether a Scheduling Coordinator's market liabilities are accruing at a rate in excess of the rate over a comparable time period under the current market design. In the event this occurs, the ISO will contact the Scheduling Coordinator. The Scheduling Coordinator will then be in the position of determining whether any of its scheduling or bidding behavior is contributing to its high charges and take corrective action. This information can also be used by the ISO to determine whether there are any price anomalies that should be reviewed and potentially cause the ISO to take further corrective action. Section IV below discusses the tools and authorities the ISO can utilize when problems arise after *go-live*.

C. Stability of the Market Simulation Environment and Completion of the Integrated Market System Update 2 Exit Criteria

Both the ISO and Market Participants shared frustration regarding stability issues throughout the long course of market simulation during more than 18 months in 2007 and 2008. The length of the market simulation process is attributable to numerous factors, including the decision to conduct testing in phases as functionality became available, rather than waiting until the systems were largely finished. The phased testing approach would have resulted in a lengthy simulation process even without unanticipated challenges which extended the simulation. In practice, the phased approach resulted in frequent software changes, struggles with only partial functionality, and diversion of ISO resources from development and support of the software itself to support market simulation.

The ISO is satisfied that it achieved the main objectives of Integrated Market System ("IMS") Update 2: confirm the connectivity of the market to the ISO systems, test the performance of the software functionalities in analyzing various test cases, assess the ability of the software to produce results as expected and understand how bidding and scheduling behavior affect prices based on the system constraints. Accordingly, the ISO made the decision to exit Market Simulation (IMS) Update 2 and move into Parallel Operations Simulation in January 2009.[23] The Parallel Operations Simulation includes four components: system operations testing, Grid Operations training with scenarios, pre-production, and cutover to MRTU. The move from a pure market simulation into the Parallel Operations Simulation permits more realistic tests of MRTU regarding system stability than were possible under the prior market simulations.[24] Any remaining objective can be achieved in this next phase of testing prior to *go-live.*

The ISO established 21 exit criteria for IMS Update 2 with Market Participants in 2007. Through extensive market simulations with Market Participants, 19 of these criteria were satisfied. The other two exit criteria relate to settlements and variance availability. As discussed above in Section III.B,

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[23] Activities planned for the Parallel Operations Simulation are described in the MRTU Parallel Operation Simulation Test Supplement (v1.6) at: http://www.caiso.com/2334/233484633dea0.pdf.

[24] Features of the four components of the Parallel Operations Simulation are discussed further below.

settlements issues are largely resolved and the ISO is devoting necessary resources to address any remaining settlements' related issues.

The exit criteria regarding variances called for all critical and very high variances to be resolved and all high variances to be resolved or mitigated. During the simulation over 3,250 issues listed as either high, very high, or critical have been resolved. Following software patches that will go into production in the next few days, 44 high issues remain open, and there are no very high or critical issues remaining. Most of these will be resolved by the end of January, either through software patches, or through resolution of business questions with participants.

Market Participants file 10-20 issues daily with the ISO ranging from training questions to system issues they are experiencing. This is similar to the level of issues that arise in the ISO's current market design. The ISO intends to address these remaining issues without affecting Market Participant readiness.

The ISO has instituted a "freeze" on non-essential system codes changes and will stop patching MRTU applications that are externally facing unless the change has been reviewed with Market Participants and they have time to modify their software. Effective February 1, the ISO will only fix critical variances that are needed for *go-live* and do not affect Market Participant software. If any major variances are found after March 1, the ISO will notify the Commission and will work with Market Participants to fix the issue. None of the current open issues appear to be material issues that will impact the ISO's ability to open the market on March 31.

D. ISO Grid Operations Readiness

Reliable grid operation is core to the mission of the ISO. As the ISO moves into the new market paradigm, the organization will confront the same culture shift that other ISOs and RTOs have faced, as operators are asked to work in a new environment. The ISO understands that this transition phase for Grid Operations is critical to the success of MRTU.

Thus, much of the ISO readiness effort is now focused on Grid Operations. As planned, this preparation was purposefully set relatively close to *go-live* to ensure that the grid operators are working with the final software and that training occurs close enough to *go-live* that the information will be retained.

Within the last year, grid operators have completed multiple levels of training and are now concentrating on hands-on work with generation, transmission, and scheduling processes. Work schedules for the Grid Operations staff include a week of hands-on training in the Grid Operations test laboratory where they practice the daily tasks associated with running the Day-Ahead and Real-Time Markets. On December 1, 2008, the Grid Operations staff began operating the MRTU market simulation desk in order to increase their training opportunities and provide support to Market Participants similar to what they will provide when MRTU goes live.

Additional training includes running MRTU under more than 20 operational scenarios to obtain hands-on practice for a variety of conditions ranging from normal operations to contingency situations and system emergencies. The Grid Operations staff is also working to test and confirm revised operating procedures and processes, and to finalize system functionality and operator displays in the ISO control room.

The training program also includes scenarios that replicate those that the ISO knows from experience are likely to occur. These tests are designed and conducted to help operators understand how grid reliability will be maintained at all times during the transition to the MRTU paradigm and after MRTU *go-live*. The progressive tests commence with unit control tests that will have minimal system and operational scope, will be relatively short in duration, and will be conducted in relatively stable conditions. The unit control tests are for the purpose of testing software communication between the production Energy Management System ("EMS") and the new MRTU Real-Time Market dispatch module.

Following the unit control tests, the ISO will also conduct a series of loop tests to enable and test the connection between the new market systems and the EMS. These loop tests will enable data transfers between the EMS and the Real-Time Market dispatch module to produce a market simulation solution that is based on real-time load forecasts, load following requirements, and real time outages. Connectivity and load following tests have already been successfully completed.

Since January 5, the ISO has used the production load forecast and EMS telemetry signals to feed the MRTU system. Although the ISO is not dispatching generating units using the MRTU solution, using day-to-day load forecasts and EMS telemetry allows grid operators and participants to compare the production solution and the MRTU solution. Later this month, the ISO will incorporate all production generation and transmission outages into the MRTU systems.

The ISO recognizes that the change from a regional market to a nodal market using sophisticated dispatch software is one of the most difficult cultural conversions for an operator group. Operators must work in a more complicated environment and the software will have a greater role in dispatch decision making. To address the risks of conversion, in addition to the training outlined above, the ISO will have extensive to support for the grid operators for at least the first thirty days after *go-live*. This will ensure that the grid operators have the resources on the floor to immediately address matters that arise.

As set forth in the Declaration of James W. Detmers, Grid Operations staff is conducting the necessary activities to be ready for *go-live*. If the ISO discovers any issue during this testing process that would affect the ISO's ability to implement MRTU as of March 31, 2009, the ISO will promptly inform the Commission and Market Participants.

E. Readiness of the Department of Market Monitoring

The DMM devoted substantial time and resources to MRTU readiness activities and now has a fully trained staff and has adopted a market monitoring approach that has been reviewed by the ISO's Market Surveillance Committee ("MSC") and is consistent with the approach taken by other ISOs and RTOs that operate LMP-based markets. The DMM has capabilities in place to monitor general market performance and specific areas of the MRTU market design such as Local Market Power Mitigation ("LMPM") effectiveness, bid parameters relating to unit operating characteristics, Uninstructed Deviations, activities on the interties, market up-lifts, and load under-scheduling.

The DMM is also equipped with the necessary monitoring tools, including a highly automated monitoring system and a dedicated simulation tool to re-run market "saved cases" for purposes of market monitoring ("DMM Simulation Tool"). This simulation tool allows the DMM to replicate actual market outcomes in an off-line study mode and re-run the markets with modified inputs (*e.g.*, bids) to conduct analyses for assessing the market impacts of potential bidding behavior or other key market inputs (*e.g.*, transmission or generator outages). The DMM has used the Day-Ahead Market component of the DMM Simulation Tool over the past several months to develop automated simulations using different supply bids (*e.g.*, cost-based bids that produce competitive benchmark prices) and in testing the effectiveness of the Day-Ahead LMPM procedures.

The DMM has worked with the ISO Information Technology unit to implement processes for better ensuring that the DMM Simulation Tool is consistently available and working for all markets (the Day-Ahead, HASP, and Real-Time Markets) and is consistently updated and synchronized with the same version of the market software that will be used following MRTU *go-live*. In the time leading up to *go-live*, the DMM will also focus on further developing and testing monitoring metrics through shadow monitoring of the MRTU market simulation, completing the calculations for Frequently Mitigated Units, and finalizing the competitive path assessments used in the LMPM procedures.

As discussed in the attached Declaration of Keith Casey, Director of the DMM,[25] the MRTU Readiness Criteria Dashboard attached to the ISO's December 8, 2008 MRTU status report listed four issues under readiness criterion ORG-3.3 that were impeding the performance and availability of the DMM market simulation tool. Accordingly, this criterion was given an Orange status in the December 8 dashboard.[26] The ISO is actively working on addressing these issues and is committed to providing the DMM with the capability it needs for *go-live*. As Dr. Casey explains in his declaration, with

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[25] See Attachment 5 to the instant filing.

[26] ORG-3.3 is included under overall readiness criterion ORG-3, which also includes criteria ORG-3.1 and ORG-3.2. Although both ORG-3.1 and ORG-3.22 had a Purple status in the December 8 dashboard, the Orange status of ORG-3.3 in that dashboard resulted in overall criterion ORG-3 also having a status of Orange there.

continued focus and dedication of the ISO's resources, he anticipates that the issues can be sufficiently resolved in advance of the MRTU *go-live* date of March 31, 2009. Accordingly, the ORG-3.3 criterion now has a Purple status in the MRTU Readiness Criteria Dashboard attached to the instant filing. This change has resulted in a Purple status for the higher level criterion ORG-3 indicating that the ISO as an organization is fully on track for *go-live*.

IV. MRTU Cutover Planning and Post MRTU Contingency Planning

The ISO's cutover and reversion plan describes the activities that the ISO and Market Participants will take to transition to the MRTU design. The cutover involves the move from the ISO market design and software to the MRTU market design and software. The reversion plan describes the process for reverting to the pre-MRTU tariff in the unlikely event, and as a last resort, that the ISO finds that it cannot operate the grid reliably after all efforts to maintain operations under MRTU have been considered. The ISO engaged with stakeholders and developed an extensive cutover and reversion plan called the MRTU Cutover and Reversion External Overview and Detail ("Cutover and Reversion Plan").[27] The ISO and Market Participants discussed the Cutover and Reversion Plan a number of times, and the plan will continue to evolve as the final details are determined. The MRTU Implementation Workshops of November 20 and December 18 addressed the Cutover and Reversion Plan in detail.[28] In February 2009, the ISO will finalize the Cutover and Reversion Plan following a walk-through with Market Participants to confirm any changes to that plan.[29] The ISO has established a Rapid Response Team to engage in post-implementation contingency planning to ensure that all efforts are made to avoid reversion.

A. Cutover

Pursuant to the Cutover and Reversion Plan, the ISO and Market Participants will undertake various activities, including testing, to ensure that they are able to transition smoothly (*i.e.*, cut-over) from the currently effective ISO market design and software to the market design and software that will be used following MRTU *go-live*.

The ISO has prepared an "MRTU Pre-Production Simulation Plan" (Pre-Production Plan) to set forth activities that need to be undertaken during the time leading up to MRTU *go-live*.[30] The Pre-Production Plan is intended to ensure

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27 The Cutover and Reversion Plan was included in draft format in Attachment 8.3 to the ISO's December 8, 2008 MRTU status report. Documents related to the Cutover and Reversion Plan can be found on the ISO website at http://www.caiso.com/18ae/18ae96b71f1a0.html.

28 Information regarding the MRTU Implementation Workshops is available on the ISO website at http://www.caiso.com/docs/2005/06/21/2005062113583824742.html.

29 The ISO has scheduled a further stakeholder meeting on January 22 to discuss the Cutover and Reversion Plan, which the ISO intends to finalize by February.

30 The Pre-Production Plan was included in draft format in Attachment 8.2 to the ISO's December 8, 2008 MRTU status report. The current version of the Pre-Production Plan is set forth in Section 11 of the MRTU Market Simulation Guidebook, which was most recently modified

proper integration of the MRTU processes and software with the EMS and other production systems. Also, the ISO will be establishing an Operations Center and a Solution Center that will be staffed around-the-clock shortly before *go-live* and as long as necessary after *go-live*. The Operations Center will contain critical Operations, Market, and Information Technology management and staff that can instantly assist the control room as needed if issues or questions arise. The Solutions Center will be an extension of the participant communication processes (*i.e.*, hot line, issue tracking, *etc.*) that have been in place during simulation and parallel operations. By having readily available all necessary resources, the ISO believes that any issues that may arise can be quickly overcome.

B. Post-Implementation Contingency Planning

In addition, the ISO has established a mechanism to address unanticipated issues or problems that arise following MRTU *go-live*. The ISO developed a Rapid Response Team which will swiftly address any market issues that may arise after MRTU *go-live*. This is a team made up of ISO staff from many departments within the ISO, including DMM, Market & Infrastructure Development, Operations (including Settlements), Information Technology, Legal, Regulatory Affairs, Communications, and Customer Service. The team is currently engaged in contingency planning efforts in preparation for *go-live*, and after *go-live* the team will meet frequently, initially daily, to consider market system and performance issues, indications of market design deficiencies, and evidence of market manipulation and gaming. To the extent the Rapid Response Team identifies issues that require ISO action, the ISO intends to use the broad range of tools available to it either under the MRTU Tariff or under Commission precedent. Such issues include the need to address instances where the software is not working correctly and instances where the software is working correctly but is producing anomalous prices or other anomalous results. These tools include the administrative pricing and Exceptional Dispatch provisions of the MRTU Tariff, and the ability to make changes to BPM in exigent circumstances. The ISO can also file with the Commission for changes to the MRTU Tariff or temporary waivers of Tariff provisions (with a request for expedited consideration if warranted). These tools will allow the ISO to take prompt corrective action to minimize the extent of any harm that might be caused by any anomalous event.

In the unlikely and unanticipated event that more fundamental concerns arise after MRTU implementation, the ISO can also exercise its authority under the MRTU Tariff to revert to the prior tariff and market design following MRTU *go-live*. The Cutover and Reversion Plan provides details regarding the reversion process and has gained considerable stakeholder support.

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on December 12, 2008, and is available on the ISO website at http://www.caiso.com/18d3/18d3d1c85d730.pdf.

V. Other Indicia of MRTU Readiness

A. ISO Business Unit and Staff Readiness

The ISO's business units and staff are on track to be prepared for MRTU implementation on the *go-live* date of March 31, 2009. The readiness of the ISO for MRTU implementation is reflected in the attached Declarations of the ISO President and Chief Executive Officer, Yakout Mansour; Vice President of Corporate Services, Stephen Berberich; Vice President of Operations, James W. Detmers; and Director of the DMM, Keith Casey.[31] The declarants oversee all of the ISO business units and staff that have core MRTU responsibilities, and, based on their own involvement in the preparations for MRTU *go-live*, they are in the best position to know that all ISO personnel will be ready for *go-live*.

In addition to the preparations made by the DMM and Grid Operations unit for MRTU implementation as described in Section III above, all ISO business units have completed detailed readiness activities that included phases for planning, analysis, design, build, and implementation. The business owners in each business unit provided final sign-off for all high-priority business processes as of September 2008. Sign-off included end-to-end testing, identification and mitigation of gaps and the drafting of SAS 70 controls for each business process.[32] Thus, all business units are currently on course for a successful MRTU launch, with only a few readiness activities pending completion, and the ISO anticipates that those few will be completed by MRTU *go-live*.

ISO personnel training regarding MRTU systems, processes, and timelines is also complete. Classes organized by the ISO covered topics such as market operations and timelines and the Settlement process at multiple levels of detail – introductory (Level 100), intermediate (Level 200), and advanced (Level 300). Further, Level 400 courses with hands-on training were required for staff having certain areas of responsibility, such as staff in Operations and Information Technology.[33]

B. External Readiness

To help attain the successful participation of a wide variety of diverse Market Participants, in addition to maintaining an ongoing testing environment, the ISO offered Market Participants a wide-ranging curriculum of MRTU training courses, conducted a series of workshops associated with topics like

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[31] The Declarations of Messrs. Mansour, Berberich, Detmers, and Casey are provided in Attachments 2 through 5 of the instant filing.

[32] "SAS 70" is an abbreviation for Statement on Auditing Standards No. 70: Service Organizations. SAS 70 defines the professional standards used by a service auditor to assess the internal controls of a service organization and issue a service auditor's report.

[33] MRTU training information is available on the ISO website at http://www.caiso.com/docs/2005/10/07/200510071157559066.html.

cutover/reversion, manned a market simulation hotline, and conducted ongoing readiness assessments.

The ISO provided training options through more than 60 instructor-led sessions, and computer-based modules are available on the ISO website. In the last two years, more than 3,500 representatives from participant organizations have attended instructor-led training sessions hosted at the ISO and throughout the country.

The ISO Customer Service team maintains a market simulation hotline for the purposes of answering questions posed by Market Participants, troubleshooting inquiries, and logging issues that require research for resolution. To date, as mentioned in Sections I and III.C, above, the ISO has responded to and closed a total of more than 3,250 issues reported by Market Participants regarding the market simulation, and only a small fraction of that number of issues remain open. As will also be the case in MRTU production, until *go*-live the ISO will continue to address and resolve Market Participant issues, including on a one-on-one basis, as they come in and as soon as possible.

Finally, the ISO has conducted four Market Participant Readiness Assessments consisting of MRTU-related questions in the areas of communication, market simulation, training, functional surveys, and organizational and technical readiness. The initial Market Participant Readiness Assessment concluded in January 2007 and set a baseline for the resources needed to prepare Market Participants for a successful MRTU launch. In August 2007, the ISO completed a second Readiness Assessment that gauged the progress made in attaining readiness and identified additional Market Participant needs. In July 2008, the ISO included with its third Readiness Assessment a request that Market Participants comment on the usability of the MRTU system interfaces. The fourth Market Participant Readiness Assessment concluded in October 2008. The final Market Participant Readiness Assessment will be completed in February 2009. The ISO notes that readiness criterion PRT-1, which requires the ISO to use its Readiness Assessments to assist in assuring that at least 80 percent of the active Market Participants are ready prior to *go-live*, was assigned an Orange status in the ISO's November 2008 MRTU Readiness Criteria Dashboard. Because the ISO's final Readiness Assessment is scheduled for February 2009, the Orange status given to readiness criterion PRT-1 in the MRTU Readiness Criteria Dashboard attached to the December 8, 2008 MRTU status report has been changed to Purple in the MRTU Readiness Criteria Dashboard attached to the instant filing.

C. Independent Certifications of ISO Readiness to Implement MRTU

As explained in Sections III.A and III.B, above, LECG has certified that the MRTU software calculates Day-Ahead and Real-Time LMPs consistent with the MRTU Tariff, and the ISO will provide the Commission with PwC's certified audit opinion confirming whether the SaMC software calculates quantities and prices in compliance with the MRTU Tariff.

The ISO has also engaged a third independent consultant to confirm elements of MRTU readiness. The ISO contracted with Science Applications International Corporation ("SAIC") in September 2007 to verify and document, prior to implementation of MRTU, that the various new applications that constitute MRTU were developed, built, and tested in accordance with the MRTU Tariff. SAIC certified the Scheduling Infrastructure Business Rules ("SIBR"), the Market Quality System ("MQS"), the Congestion Revenue Rights ("CRR") rules, and the Integrated Forward Market/Real-Time Nodal ("IFM/RTN") software to be used under MRTU. SAIC utilized both a "top-down" and "bottom-up" approach. The top-down approach determined whether the MRTU Tariff accurately reflected the software business rules. The bottom-up approach analyzed test results to ensure consistency with the business rules and the MRTU Tariff. The following is a summary per application of the number of MRTU Tariff cites identified, the number business requirements the Tariff cites were mapped to, and the number of test cases that confirmed the functionality.

Application	Tariff Cites	Business Requirements	Test Cases	Percent Certified
CRR	188	214	866	100%
SIBR	62	177	313	100%
MQS	117	212	273	100%
IFM/RTN	487	773	782	99.5%[34]

SAIC published the results of this certification process on May 12, 2008.[35] No major issues were uncovered by SAIC with respect to either software functionality or the relationship between software systems and the MRTU Tariff. In addition to the remaining test cases, SAIC did identify a number of minor instances where the MRTU Tariff could be clarified or modified to more accurately track the MRTU Tariff business rules. The ISO has agreed to the majority of the SAIC-proposed Tariff changes, which were submitted for Commission approval in Docket No. ER09-____-000 on January 15, 2009. Those SAIC-proposed Tariff changes which were not adopted by the ISO were discussed with stakeholders. In addition, SAIC recommended that the ISO conduct further validation test cases. Pursuant to that recommendation, the ISO completed hundreds of validation tests that included the comparison of Tariff provisions with software business rules and the comparison of the ISO's results with market simulation test cases.

[34] The remaining 10 cases are currently being tested and the certification will be completed prior to *go-live*.

[35] The SAIC materials can be found at http://www.caiso.com/1fc5/1fc5d12b5460.html. Those materials were also included in Attachment 8.5 to the ISO's December 8, 2008 MRTU status report.

VI. ISO Compliance with Specific Commission Directives Related to MRTU Readiness

The Commission has directed that a number of specific issues be addressed in the ISO's readiness certification. The ISO has addressed each of these issues.

In its September 21 Order and April 20 Order, the Commission directed that the ISO's software and systems must be fully tested and ready prior to MRTU start-up.[36] As set forth in the attached Declaration of Stephen Berberich, Vice President of Corporate Services, certifying MRTU readiness, the MRTU systems, software, and tools have been tested and the ISO has the resources in place to ensure that they will function properly, barring any unforeseen developments, by the MRTU *go-live* date of March 31, 2009. The ISO's MRTU readiness is also supported by two persons who provided consulting services to the ISO in the development of MRTU, Scott M. Harvey, a director with LECG; and Petar Ristanovic, Director, Control Center Solutions Energy Automation with Siemens Energy, Inc. These declarations are provided in Attachments 4, 6, and 7 to this filing. Dr. Harvey has indicated in his declaration that the MRTU software is calculating prices consistent with the MRTU Tariff. In his declaration, Mr. Ristanovic has indicated that Siemens can resolve any known software issues prior to implementation and that Siemens has committed the resources necessary to resolve any issues that may come up during the transition and even after *go-live.* Mr. Ristanovic has also declared that, based on his experience with developing software systems with a similar level of complexity, the scope and extent of the ISO's testing of the MRTU software exceeds the scope and extent of software testing undertaken by other entities in comparable circumstances.

The September 21 Order also directed the ISO to include in its readiness criteria a specific criterion providing "an assessment of the system's effectiveness when responding to instances where demand bids exceed supply bids."[37] This readiness criterion has been tracked as MKS-1, and is reflected in Scenario 10 of the IMS Update 2 Scenario Executions. As explained in the MRTU status report filed by the ISO on December 8, 2008,[38] this scenario ran for trade date September 20, 2008, the preliminary results were provided for Market Participant review,[39] and the ISO posted a final report regarding the scenario on the ISO website.[40] In brief, the results were consistent with the expected outcome of the scenario and included higher prices, curtailment of some self-scheduled demand, and reduction in exports.

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36 September 21 Order at P 1414; April 20 Order at PP 188, 670.

37 September 21 Order at P 1415.

38 See Attachment 8.6 (MRTU Readiness Criteria Dashboard) to the MRTU status report filed on December 8, 2008, at page 11.

39 See the ISO website at http://www.caiso.com/204e/204e785f5d300.pdf.

40 See the ISO website at http://www.caiso.com/2076/2076dd7b34a0.pdf.

In its April 20 Order, the Commission concluded "that curtailment priority of exports from generating units that have committed only part of their output as RA [Resource Adequacy] capacity in ISO must be resolved prior to MRTU."[41] The Commission therefore concluded that, "[a]s part of its readiness certification, we direct the ISO to affirm that the MRTU systems and software can accommodate partial RA units or that the ISO has developed a manual work-around."[42] The ISO hereby certifies that the MRTU systems and software can accommodate exports from generating units that have committed only a portion of their output as RA capacity. At one time, the ISO considered implementing the curtailment priority of exports for "partial RA units" using a manual work-around process. However, after evaluating the complexity of tracking exports being supported by non-RA capacity, especially considering that the supporting resources may only be partial RA, the ISO decided instead to implement a software-based solution that recognizes that only a portion of a resource's capacity may be RA. This solution will explicitly allow an export seeking the same priority as ISO Demand to identify an energy bid coming from the non-RA capacity of a partial RA unit.[43]

Further, in the April 20 Order, the Commission concluded that "a sound transition to MRTU should include a contingency plan that addresses any failure of MRTU software and systems to function as designed."[44] The Commission therefore indicated that the ISO's readiness certification should include a description of the ISO's contingency plan.[45] In compliance with this directive, the ISO has engaged with stakeholders and has developed an extensive Cutover and Reversion Plan and taken other steps as discussed in Section IV above. For the reasons described in Section IV, the ISO satisfies this requirement of the April 20 Order.

In the April 20 Order, the Commission also directed the ISO to "include in its readiness activities a stakeholder process to further address concerns raised by commenters about e-tagging rules."[46] The ISO has established the stakeholder process required by the Commission and has posted, on the ISO website, business rules regarding e-tagging under MRTU.[47] The ISO also is

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41 April 20 Order at P 202.

42 *Id.*

43 The ISO also notes that the Commission, in an order issued in the MRTU proceeding on March 24, 2008, directed the ISO to clarify in the MRTU Tariff that, "for a partial Resource Adequacy resource's self-provided ancillary services capacity, the ISO would only be able to disqualify the portion of the capacity that has an Energy offer obligation." *California Independent System Operator Corp.*, 122 FERC ¶ 61,271, at P 116 (2008). The ISO included the required changes to the MRTU Tariff in a compliance filing submitted in Docket Nos. ER06-615 and ER07-1257 on May 19, 2008.

44 April 20 Order at P 246.

45 *Id.*

46 *Id.* at P 230.

47 See http://www.caiso.com/1899/18998ffe653b0.html; http://www.caiso.com/2098/2098c33219ae0.html; http://www.caiso.com/1c2c/1c2ce98146730.pdf.

actively engaged in the work group discussions of the Western Electricity Coordinating Council ("WECC") Seams Issues Subcommittee ("SIS") regarding e-tagging requirements. These work group discussions are open to input from interested stakeholders. In those discussions the ISO committed to follow all applicable North American Electric Reliability Corporation ("NERC") and WECC e-tagging requirements.[48] On October 4, 2007, the SIS issued a report in which it "concluded [that] MRTU does not create any new seams issues related either to e tagging or market timelines."[49] Further, the ISO presented and discussed its e-tagging requirements at the August 8-9, 2007, meeting of the WECC Interchange Scheduling and Accounting Subcommittee ("ISAS"). Prior to that ISAS meeting, the ISO also issued a Market Notice announcing its participation at the meeting so that Market Participants could participate in the discussion if they so chose. No specific issues of concern were raised at the ISAS meeting with respect to the ISO's e-tagging requirements.[50] Thus, any concerns regarding e-tagging have been resolved.

The Commission, in the April 20 Order, also stated that, in the event software changes need to be made as a result of completing the BPMs, the impact of such changes "will be addressed in the readiness certification process."[51] The ISO notes that all software changes related to the finalization of the BPMs – with the possible exception of changes to BPMs that may be required to implement pending tariff amendments – have either already been successfully added to the MRTU software or are currently in testing and will be included in MRTU prior to commencing pre-production. Any changes stemming from pending tariff amendment filings will be implemented either through software changes, manual processes, or a combination thereof.

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48 California Independent System Operator Corporation Joint Quarterly Seams Reports for the Third Quarter of 2007, Docket No. ER06-615-002 (filed Oct. 10, 2007), at 12 ("October 2007 Quarterly Seams Report").

49 *Id.* at Attachment F, pages 12-13 (containing the SIS's report).

50 October 2007 Quarterly Seams Report at 12.

51 April 20 Order at P 659.

VII. Remaining Activities and Essential Milestones

As discussed above, many critical MRTU-related activities and milestones are already complete. Certain activities and milestones still remain prior to implementation of MRTU. The primary remaining activities and milestones, and the anticipated time frame[52] by which the ISO anticipates they will be completed, are:

Jan. – Feb.	Continue to publish daily and monthly settlement statements to allow Market Participants to validate Charge Codes and test their systems.
Jan. – March	Continue to finalize procedures and exercise post *go-live* processes for grid operators.
February	Test "fail over" procedures for utilizing the ISO alternative Control Center.
	Finalize the MRTU Cutover and Reversion Plan.
	Develop a process to validate prices, and if necessary, correct them prior to publication. The ISO will use the price validation and correction tools already in place pursuant to the MRTU Tariff.
	Begin the process of allocating and auctioning monthly CRRs to Market Participants for April 2009.[53]
March	Begin pre-production (on 3/1) and initiate cutover activities (on 3/15).
	Ten days prior to *go-live*, issue a Market Notice affirming continued MRTU readiness and reporting any pending requirements.
	Three days prior to *go-live*, issue a Market Notice confirming MRTU launch on March 31.

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[52] Although the essential milestones need to be completed, the time frame for completion is estimated. Failure to meet a milestone within an estimated timeframe does not mean that MRTU should be delayed. So long as milestones are completed prior to *go-live* and operating properly, the ISO believes that the essential milestones will have been successfully met.

[53] The ISO has already completed its annual CRR allocation and auction process for 2009. To allow simulation practice with the CRRs, the ISO is incorporating into the parallel operation simulation the 2009 annual CRRs that were allocated and auctioned. While the ISO does not have CRRs for season 1, the ISO will be copying the season 2 CRRs to season 1 for Market Participants' usage.

At the end of March, PwC will provide a certified audit opinion confirming that the SaMC software calculates quantities and prices in compliance with the MRTU Tariff.

If for any reason the ISO determines that, due to an inability to attain any critical milestone, the ISO will be unable to implement MRTU as of March 31, 2009, it will so inform the Commission and Market Participants as soon as possible.

VIII. Known Issues Requiring Resolution Prior to *Go-Live*

The following are the known, significant issues that are pending resolution:

- Energy and cost accounting issues associated with real-time bids for Pumped-Storage Hydro Units.

- Systems should recognize and not shut down resources in real-time that are unable to honor their Day-Ahead Market commitments.

- Add point of delivery pricing location to the Master File for resources modeled at locations other than their interconnection point which impacts Open Access Same-Time Information System ("OASIS") reporting.

- Tune Real-Time Market systems to ensure that an issue with Short-Term Unit Commitment ("STUC") solution timing is resolved and solution infeasibilities are minimized.

- Honor resource start times in RUC and real-time, ensuring they are not dispatched earlier than is operationally feasible based on the unit's down time.

- Cross-hour ramping results are inconsistent for resources with multiple ramp rates and offering regulation ramps.

- Resource-specific prices are inconsistent with the associated Pricing Node or Aggregated Pricing Node prices.

- Spin and non-spin quantities published in the CAISO Market Results Interface ("CMRI") are inconsistent with original SaMC Self-Provided Spin Capacity. This will resolve the observed dropping of self-provided spin and non-spin.

- Adhere to WECC interchange scheduling convention that requires interchange values to be an integer value.

- OASIS calculations for Available Transmission Capability ("ATC") and transmission usage need to correctly account for Existing Transmission Contract ("ETC")/Transmission Ownership Right ("TOR") rights.

- Enforce the daily energy limit of resources consistently in the Real-Time Market. It should be noted that daily Energy limit is a soft constraint and there may be legitimate solution reasons that daily Energy limit could be exceeded in extreme cases.

- Correctly account for power flow losses by adjusting load when a direct current ("DC") solution is necessary.

- An inconsistent SIBR rule does not allow exports not associated with capacity from a supporting resource to receive the same high priority as exports that are associated with capacity from a supporting resource.

IX. Status of Commission Filings and Request for Commission Action

The Commission has recently acted on many filings relating to the MRTU initiative that were pending before the Commission. The ISO appreciates the efforts of the Commission and its staff resulting in these recent Commission orders on MRTU. The ISO believes it is important for the Commission to act on certain additional filings prior to implementation of MRTU. Commission action on these filings will resolve critical open questions that must be answered for a successful implementation of MRTU. As such, the ISO respectfully urges the Commission to rule on the following filings by March 1, 2009, to reduce regulatory uncertainty for both the ISO and its Market Participants:

(1) July 21, 2008, request for clarification or in the alternative rehearing in Docket No. ER08-73 addressing how the ISO should calculate caps for Start-Up and Minimum Load Costs, and related compliance filing submitted on the same date.

(2) July 21, 2008, request for clarification or in the alternative rehearing in Docket Nos. ER06-615 and ER07-1257 addressing the allocation to Metered Subsystems ("MSSs") of tier 2 Integrated Forward Market ("IFM") Bid Cost Recovery ("BCR") Uplift Payments costs, and related compliance filing submitted on the same date.

(3) October 31, 2008 filing in Docket No. ER09-213 modifying the MRTU Tariff to reflect elements of the MRTU design that will be deferred to after MRTU *go-live* and implementing work-arounds to reflect such deferrals.

(4) November 3, 2008 filing in Docket No. ER09-241 establishing an interim price cap and minimum price during the initial implementation of MRTU.

(5) November 4, 2008 filing in Docket No. ER09-240 adding software pricing parameters to the MRTU Tariff and addressing compliance with the Commission order regarding load aggregation demand clearing.

(6) January 15, 2009 filing in Docket No. ER09-____ containing miscellaneous MRTU Tariff clarifications based on findings by the SAIC audit of the tariff, and other miscellaneous tariff clarifications.

The ISO notes that action on a number of proposed Tariff revisions related to the ISO's Exceptional Dispatch authority and payments to resources that receive Exceptional Dispatches are still pending before the Commission in Docket Nos. ER08-1178 and EL08-88. Although Commission action on these Exceptional Dispatch issues prior to *go-live* is not essential from an operations perspective, resolution of these issues will provide greater certainty on compensation and settlement issues and will avoid the need for potentially burdensome refund calculations in the months after MRTU *go-live*. Similarly, on November 25, 2008, the ISO made its filing on compliance with the Commission's September 19, 2008 order on the Integrated Balancing Authority Area filing in Docket ER08-1113.[54] The ISO is proceeding with the implementation of the procedures for Market Efficiency Enhancement Agreements and the marginal losses adjustment procedures as proposed in its compliance filing. While an order is not essential from an operations perspective, confirmation of the approaches filed on compliance would avoid any refunds after *go-live*.

Also, the ISO has made or intends to make a number of additional filings with the Commission prior to MRTU implementation. The ISO does not believe it is necessary for the Commission to issue orders on these filings prior to MRTU *go-live*. Nevertheless, Commission orders on these pending matters prior to *go-live* would also serve to reduce regulatory uncertainty for both the ISO and its Market Participants. The filings in this category include the following:

(1) Pursuant to a directive in the Commission's December 4, 2008 order,[55] the ISO will submit an informational filing of the MRTU Tariff sheets showing a March 31, 2009 effective date, to be filed prior to *go-live*.

(2) MSS Agreements updated for MRTU (with the City of Riverside, filed on October 31, 2008, in Docket No. ER09-188; with the Northern California Power Agency, filed on November 7, 2008, in

[54] *California Independent System Operator Corp.*, 124 FERC ¶ 61,271 (2008).
[55] *California Independent System Operator Corp.*, 125 FERC ¶ 61,262, at P 119 (2008).

Docket No. ER09-259; with Silicon Valley Power, filed on November 13, 2008, in Docket No. ER09-292; with the City of Vernon, filed on November 20, 2008, in Docket No. ER09-321; and with the City of Anaheim, filed on November 24, 2008, in Docket No. ER09-332).

(3) Request for a waiver of OASIS requirements under MRTU that is similar to the existing waiver of OASIS requirements under the ISO's current market design to be filed the week of January 19, 2009.

(4) Amended and Restated Big Creek Physical Scheduling Plant Agreement to conform to MRTU, filed on November 26, 2008, in Docket No. ER09-344.

(5) Filing to explain the calculation of ATC under MRTU filed on January 15, 2009, in Docket No. OA08-12-004.

(6) Enhancements to the ISO's credit policies to be filed by January 29, 2009 (61 days prior to March 31).

(7) Filing to comply with directives regarding the underscheduling penalty requirement in the Commission's December 19, 2008 order in Docket No. ER06-615,[56] to be filed on January 21, 2009.

X. Materials Submitted in Support of the Instant Filing

Attachment 1	Resolution of the ISO Governing Board approving the submission of the instant readiness filing
Attachment 2	Declaration of Yakout Mansour, ISO President and Chief Executive Officer, Certifying MRTU Readiness
Attachment 3	Declaration of James W. Detmers, Vice President of Operations, Certifying MRTU Readiness
Attachment 4	Declaration of Stephen Berberich, Vice President of Corporate Services, Certifying MRTU Readiness
Attachment 5	Declaration of Keith Casey, Director of Department of Market Monitoring, Certifying DMM Readiness
Attachment 6	Declaration of Scott M. Harvey, Director with LECG

56 *California Independent System Operator Corp.*, 125 FERC ¶ 61,339 (2008).

Attachment 7	Declaration of Petar Ristanovic, Director, Control Center Solutions Energy Automation with Siemens Energy, Inc.
Attachment 8	MRTU Readiness Criteria Dashboard, dated January 16, 2009
Attachment 9	DMM Pricing Report, dated January 16, 2009

XI. Conclusion

For the foregoing reasons, the ISO respectfully requests that the Commission accept the MRTU readiness certification provided in the instant filing and the attached declarations certifying MRTU readiness, effective as of March 31, 2009, as complying with the Commission's directives in the September 21 Order.

January 16, 2009

Respectfully submitted,

/s/Sidney M. Davies

Nancy Saracino
General Counsel
Sidney M. Davies
Assistant General Counsel
Anna McKenna
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California Independent System
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Counsel for the California Independent
System Operator Corporation

ATTACHMENT 1

Board of Governors 12/16/08 **Decision on Market Redesign & Technology Upgrade (MRTU) Program**

Motion

Whereas Management and stakeholders report significant progress on MRTU readiness since the November 24 meeting;

Whereas, assuming progress on certain essential items continues as expected, Management and stakeholders report that a March 31, 2009 go live date is achievable;

Whereas, Management is committed to making every effort to go live on March 31, 2009, and the stakeholders share that commitment;

Therefore,

1) The Board directs Management to file a readiness certification with the Federal Energy Regulatory Commission for a March 31, 2009 go live date;

2) The readiness certification should be filed no later than January 16, 2009, and should identify all milestones and assumptions that are essential for a March 31 go live date;

3) The Board will continue to monitor progress toward a March 31 go live date at its scheduled meetings.

Moved: Page **Second: Capuano**

Board Action: **Passed**	Vote Count: **5-0-0**
Capuano	**Y**
Doll	**Y**
Gage	**Y**
Page	**Y**
Willrich	**Y**

Motion Number: 2008-12-G1

ATTACHMENT 2

Declaration of Yakout Mansour Certifying MRTU Readiness

I, Yakout Mansour, President and Chief Executive Officer of the California Independent System Operator Corporation ("ISO"), hereby declare as follows:

1. As President and Chief Executive Officer, I have overall responsibility for the ISO, including all business units within the ISO. I am also responsible for directing and leading the ISO's senior management team.

2. The ISO's Market Redesign and Technology Upgrade ("MRTU") initiative is the ISO's most important corporate objective. Since my arrival at the ISO in 2005, I have devoted substantial corporate and personal resources to ensure a successful MRTU launch.

3. Based on the Declarations of James W. Detmers, Stephen Berberich and Keith Casey (collectively "ISO Declarations") certifying the ISO's MRTU readiness and the supporting Declarations of Scott M. Harvey, and Petar Ristanovic and based on materials prepared for the ISO Governing Board and for me or for those that report directly to me and based on my own review of relevant information about MRTU readiness efforts, including testing, market simulation, and training and based on independent certifications of Science Applications International Corporation and LECG and based on the representations in the ISO Declarations that all essential milestones and assumptions set forth in the MRTU readiness certification will be attained prior to March 31, 2009, the CAISO will be ready, barring any unforeseen developments, to implement MRTU on March 31, 2009.

I hereby certify under penalty of perjury under the laws of the United States of America that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on: January 16, 2009

Y. Mansour.

Yakout Mansour

ATTACHMENT 3

Declaration of James W. Detmers Certifying MRTU Readiness

I, James W. Detmers, Vice President of Operations of the California Independent System Operator Corporation ("ISO"), hereby declare as follows:

1. As Vice President of Operations, I am responsible for the business units, including Grid Operations, Market Services and Operations Support, within the ISO that are responsible for ensuring reliable operation of the transmission assets under their operational control and for running and settling the markets to be implemented pursuant to the ISO's Market Redesign and Technology Upgrade ("MRTU") project.

2. I certify that the human resources within the business units I am responsible for will be ready for MRTU *go-live* once the planned training scheduled between now and *go-live* is complete, and that MRTU business processes are either in place or are under development to be in place prior to MRTU *go-live*.

3. Based on materials prepared for the ISO Governing Board and for me or for those that report directly to me, and based on my own review of relevant information and direct involvement with MRTU readiness efforts, including testing, market simulation and training, and based on independent certification of Science Applications International Corporation and LECG and on my opinion that the essential milestones and assumptions set forth in the MRTU readiness certification filing will be attained, the ISO is ready, barring any unforeseen developments, to implement MRTU on March 31, 2009.

I hereby certify under penalty of perjury that the foregoing statements are true and correct to the best of my knowledge, information, and belief.

Executed on: January 16, 2009

James W. Detmers

ATTACHMENT 4

Declaration of Stephen Berberich Certifying MRTU Readiness

I, Stephen Berberich, Vice President of Corporate Services of the California Independent System Operator Corporation, hereby declare as follows:

1. As Vice President of Corporate Services, I am responsible for the business units that support MRTU software development and operations, including Information Technology, Support & Operations, IT Projects, Energy Management System Information Technology, Operations Information Technology, and IT Corporate Systems. I am also responsible for the Program Office, which oversees implementation of the Market Redesign and Technology Upgrade ("MRTU") project.

2. I certify that the MRTU systems, software and tools have been tested and the ISO has the resources in place to ensure MRTU systems, software and tools will function properly, barring any unforeseen developments, through parallel operations, preproduction and cutover and will function properly as of MRTU *go live.*

3. I certify that the human resources within the business units I am responsible for are ready for MRTU *go live* and that MRTU business processes are either in place or under development to be in place prior to MRTU *go live.*

4. Based on materials prepared for the ISO Governing Board and for me or for those that report directly to me, and based on my own review of relevant information and direct involvement with MRTU readiness efforts, including testing, market simulation, and training and based on independent certification of Science Applications International Corporation and LECG, and based on my opinion that essential milestones and assumptions set forth in the MRTU readiness certification filing will be attained, the CAISO will be ready to implement MRTU on March 31, 2009.

I hereby certify under penalty of perjury that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on: January 14, 2009

Stephen Berberich

ATTACHMENT 5

California ISO
Your Link to Power

California Independent
System Operator

Declaration of Keith Casey Certifying Department of Market Monitoring Readiness

I, Keith Casey, Director of the Department of Market Monitoring ("DMM") of the California Independent System Operator Corporation ("ISO"), hereby declare as follows:

1. As Director of the DMM, I am responsible for directing the activities of the DMM business unit, which independently monitors the performance of the ISO markets under the ISO's current market design and will continue to independently monitor the performance of the ISO markets under the Market Redesign and Technology Upgrade ("MRTU").

2. The DMM staff is adequately trained for monitoring the markets under MRTU.

3. The DMM has adopted a market monitoring approach that is consistent with the market monitoring approach employed by other Independent System Operators and Regional Transmission Organizations that operate markets based on locational marginal prices.

4. The DMM has the ability to monitor general market performance and specific areas of the MRTU market design including but not limited to effectiveness of local market power mitigation measures, bid parameters relating to unit operating characteristics, uninstructed deviations, activities on the interties, market up-lifts, and load under-scheduling.

5. The DMM has consulted frequently with the ISO Market Surveillance Committee (MSC) in developing its MRTU monitoring metrics and analytic approaches.

6. The DMM has met with other ISO business units and developed procedures and clarified roles and responsibilities for monitoring operational and market issues to ensure effective coordination and mitigate any monitoring gaps.

7. The DMM is equipped with the market monitoring tools it requires, including a highly automated monitoring system and a dedicated market simulation environment.

8. In regard In regard to the dedicated market simulation environment, Attachment 8.6 to the ISO's December 8, 2008, MRTU Status Report listed four issues under readiness criterion ORG 3.3 that were impeding the performance and availability of the DMM market simulation tool. The four issues are: (1) implement procedures for consistently providing the save case data required to run the market simulation tool; (2) resolve software/system issues necessary to run HASP/RTM software in automated batch mode, rather than manually from user interface; (3) implement IT procedures that ensure the DMM simulation tool is operating with the same version of market software as the production environment; and (4) provide documentation on parameter settings used for each market run in production so that DMM can replicate those settings in the simulation tool. At the time of the status report, it was expected that these four issues would get resolved in December. To date, only the first issue (Implement procedures for consistently providing the save case data required to run the market simulation tool) has been largely resolved. While progress has been made on the remaining three issues, they are not yet sufficiently resolved. However, the ISO is committed to addressing these issues and I believe that with continued focus, they will be sufficiently resolved in advance of the MRTU *go-live* date of March 31, 2009.

I hereby certify under penalty of perjury that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on: January 13, 2009

Keith Casey

Director, Department of Market Monitoring California ISO

ATTACHMENT 6

Declaration of Scott M. Harvey

I, Scott M. Harvey, am a director with LECG and hereby declare as follows:

1. I was retained by the California Independent System Operator Corporation ("ISO") to review the results of the ISO's analysis track testing of its dispatch and pricing software to be used to implement its Market Redesign and Technology Upgrade ("MRTU") project. The purpose of the ISO analysis track testing was to test the software that has been developed for operating the MRTU markets under the pricing rules described in the MRTU tariff filed with the Federal Energy Regulatory Commission.

2. In preliminary, interim, and final written reports prepared by me or under my supervision and dated April 16, 2008, July 1, 2008, and October 20, 2008, respectively, I concluded that, based on the analyses described in these reports, no substantial unresolved problems were observed that would prevent the ISO software systems from calculating prices consistent with the MRTU tariff and the locational marginal pricing ("LMP") methodology, and no material unresolved problems were observed that would prevent the software systems from committing and dispatching load and generation based on least bid cost consistent with the MRTU tariff.

3. At a meeting of the ISO Governing Board held October 28, 2008, I reported that the ISO's MRTU software was functioning as well as or better than had the market software developed by other Independent System Operators and Regional Transmission Organizations at a similar stage in their preparation for implementation of LMP-based markets.

4. I hereby certify under penalty of perjury under the laws of the United States that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on January 8, 2009

Scott M. Harvey

Scott M. Harvey

ATTACHMENT 7

Declaration of Petar Ristanovic in Support of MRTU Readiness

I, Petar Ristanovic Director, Control Center Solutions Energy Automation with Siemens Energy, Inc. ("Siemens"), hereby declare as follows:

1. The California Independent System Operator Corporation ("ISO") selected Siemens to develop the core components of a comprehensive energy market management software system for the ISO's new locational marginal pricing market design known as the Market Redesign and Technology Upgrade ("MRTU") project.

2. The remaining software issues requiring resolution are known and limited. Siemens has the resources and the capability of addressing all such issues prior to March 31, 2009.

3. Up to and following the implementation of MRTU, Siemens will, to the extent necessary, commit sufficient resources to ensure a smooth transition between the software system the ISO uses under its current market design and the Siemens software system the ISO will use under MRTU, and such resources will be available as needed after the transition to address any issues that arise as promptly as possible.

4. Based on my experience with developing software systems with a similar level of complexity, I conclude that the scope and extent of the ISO's testing of the MRTU software exceeds the scope and extent of software testing undertaken by other entities in comparable circumstances.

5. Based on the foregoing, I conclude that the software systems provided by Siemens will be ready for the ISO to implement MRTU on March 31, 2009.

I hereby certify under penalty or perjury under the laws of the United States that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on: January 14, 2009

Petar Ristanovic,

Director, Control Center Solutions
Energy Automation, Siemens
Energy, Inc.

ATTACHMENT 8

MRTU Readiness Criteria Dashboard

January 16, 2009

This Dashboard is designed to display the status of each MRTU Readiness Criteria. Readiness Criteria status is indicated by the following color codes:

- Clear: A Readiness Criterion is clear (C) if:
  - The Readiness Criterion has not begun.
- Purple: A Readiness Criterion is purple (P) if:
  - The completion or status updates are on schedule based on the specified target due date or milestone, OR
  - A mitigating action has been implemented successfully and the Readiness Criterion is back on schedule to be completed on the specified target due date.
- Orange: A Readiness Criterion is orange (O) if:
  - One or more Readiness Components in that Readiness Criterion are not complete on the specified target due date or milestone, OR
  - A Readiness Criteria has reported risks or issues that have a potential for not allowing it to be completed on the specified target due dates or milestones.
- Blue: A Readiness Criterion is blue (B) if:
  - All Readiness Components in that category are complete.

Disclaimer:
These readiness criteria will help the CAISO to determine the status of design elements and processes that must be in place to ensure implementation of MRTU Release 1 without undue risk to the CAISO or its Market Participants. The CAISO reserves the right to revise these criteria. The CAISO's certification of readiness to be filed with FERC 60-days prior to the proposed effective date of MRTU will be based on all information available to the CAISO including, but not limited to, status of readiness criteria, including mitigating actions, advice of Market Participants and the informed business judgment of CAISO senior management.

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
BPM - 1	**BPM**	**CAISO will prepare Business Practice Manuals (BPMs), intended to contain implementation detail, consistent with and supported by the CAISO Tariff, including: instructions, rules, procedures, examples, and guidelines for the administration, operation, planning, and accounting requirements of CAISO and the markets.** **The CAISO Business Practice Manual (BPMs) will be completed and posted on the CAISO website to allow Market Participants the opportunity to review and comment on each BPM. CAISO will facilitate stakeholder review meetings to discuss critical issues. (This criterion is subject to change based on the output of the FERC Technical Conference.)** **CAISO will also establish and communicate to FERC and Market Participants a BPM change management process that describes the procedure that is used to update the BPMs after MRTU implementation.**		**3/31/08**	B		
		BPM - 1.1 **The "Initial Version Release" BPM requirements are complete.**	B	**1/19/07**			
		1. The following "Initial Version Release" BPMs are prepared and published to the CAISO website incorporating stakeholder feedback and resolved critical issues, in preparation for Business Structure Market Simulation: - BPM for Compliance Monitoring - BPM for Congestion Revenue Rights - BPM for Definitions & Acronyms - BPM for Market Instruments - BPM for Market Operations - BPM for Metering - BPM for Outage Management - BPM for Reliability Requirements - BPM for Rules of Conduct Administration - BPM for Scheduling Coordinator Certification and Termination - BPM for Settlements and Billing - BPM for Managing Full Network Model		**5/1/06 - 7/31/06**		**The following BPMs were posted on 5/1/06:** BPM for Definitions and Acronyms; BPM for Market Instruments; BPM for Market Operations; BPM for Settlements and Billing. **The following BPMs were posted on 7/31/06:** BPM for Compliance Monitoring; BPM for Congestion Revenue Rights; BPM for Definitions & Acronyms; BPM for Market Instruments; BPM for Market Operations; BPM for Metering; BPM for Outage Management; BPM for Reliability Requirements; BPM for Rules of Conduct Administration; BPM for Scheduling Coordinator Certification and Termination; BPM for Settlements and Billing; BPM for Managing Full Network Model.	
		2. Stakeholders are provided with opportunity to review, provide comments, and identify critical issues for each BPM.		**7/31/06 - 8/29/06**		Stakeholders were allowed to submit their questions / comments to the BPM In-Box up to 2 weeks prior to each BPM meeting. Stakeholder questions on each BPM and CAISO responses can be found at: http://www.caiso.com/186a/186ae8622e6f0.html	
		3. CAISO facilitates BPM review meetings for each BPM as appropriate to collect comments and discuss critical issues.		**8/29/06 - 10/5/06**		Seven organized BPM Stakeholder meetings occurred between 8/29/06 and 10/5/06. Details of each set of meetings that occurred, and which BPMs were covered can be found at: http://www.caiso.com/1872/1872e51451200.html	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		4. Revised Draft Version BPMs are posted to the CAISO website.		**1/19/07**		**The following BPMs were posted on 1/19/07**: BPM for Compliance Monitoring; BPM for Congestion Revenue Rights; BPM for Definitions & Acronyms; BPM for Market Instruments; BPM for Market Operations; BPM for Metering; BPM for Outage Management; BPM for Reliability Requirements; BPM for Rules of Conduct Administration; BPM for Scheduling Coordinator Certification and Termination; BPM for Settlements and Billing; BPM for Managing Full Network Model.	
		BPM - 1.2 **Subsequent BPM updates due to FERC requirements & Market Simulation are further developed.**	B	**8/3/07**			
		1. Stakeholders are provided the opportunity to review, provide comments, and identify critical issues for each of the Market Simulation Release BPMs that were posted on January 19, 2007.		1/19/07 - 3/2/07		A market notice was sent out on January 12, 2007 providing details to Stakeholders on how to submit comments on the revised BPMs posted on 1/19/07.	
		2. CAISO hosts Compliance Process for Business Practice Manuals call.		2/7/07		Conference call was held from 2:00 PM to 3:00 PM on 2/7/07.	
		3. CAISO drafts MRTU Tariff Language and posts to CAISO website along with reconciled BPMs.		4/2/07		All BPM revisions were posted by 6/7/07.	
		4. CAISO allows stakeholders to review and comment on BPM updates.		12/3/07		Individual BPM status can be found under the heading "BPM Completion Status Reports" at: http://www.caiso.com/17ba/17baa8bc1ce20.html BPMs have all been updated based on comments provided by stakeholders. As BPM modifications continue to occur, Stakeholders will have the opportunity to review and comment.	
		5. CAISO holds a conference call or meeting with Stakeholders on proposed MRTU Tariff Language.		4/17/07		BPM Tariff Language call was held from 1:00 PM - 4:00 PM on 4/17/07.	
		6. CAISO files additional proposed MRTU Tariff language to support BPMs and posts revised BPMs to CAISO website.		8/3/07		BPM Tariff Language was filed with FERC	
		7. The FERC Technical Conference held.		Fall 2007		Technical Conference held 9/26 - 9/27 in Washington D.C.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		8. The CAISO complies with all FERC Technical Conference directives. - Post all revised BPMs as a result of the FERC Technical Conference - File proposed Tariff Language.		11/15/07		The CAISO has posted all revised BPMs onto the CAISO website as of Nov 15th and has filed proposed Tariff Language. The following is a list of the BPMs that were revised and posted: Change Management, Compliance Monitoring, Congestion Revenue Rights, Credit Management, Definitions and Acronyms, Managing Full Network Model, Market Instruments, Market Operations, Metering, Outage Management, Reliability Requirements, Scheduling Coordinator Certification & Termination, Settlements and Billing.	
		BPM - 1.3 **CAISO BPMs are sufficiently complete for the MRTU Implementation.** *** Please note that BPMs marked "complete" are considered to be essentially complete; however, are subject to the outcome of the BPM Technical Conference, and any revisions required as a result of Testing or Market Simulation.	B	**3/31/08**		Further details on each BPM can be found under "BPM Completion Status Report" at: http://www.caiso.com/17ba/17baa8bc1ce20.html	
		BPM for Candidate CRR Holder Registration				Complete	
		BPM for Congestion Revenue Rights				Complete, revised version posted Nov 15th	
		BPM for Compliance Monitoring				Complete, revised version posted Nov 15th	
		BPM for Change Management				Complete; See Readiness Criterion BPM 1.4 for status	
		BPM for Credit Management				Complete, revised version posted on September 12th	
		BPM for Definitions and Acronyms				Complete, revised BPM posted on September 21	
		BPM for Managing the Full Network Model				Complete, revised version posted on Nov 15th	
		BPM for Market Instruments				Complete, revised version posted on Nov 15th	
		BPM for Market Operations				Complete, revised version posted Nov 15th	
		BPM for Metering				Complete, revised version posted Nov 15th	
		BPM for Outage Management				Complete, revised version posted on Nov 15th	
		BPM for Reliability Requirements				Complete, revised version posted Nov 15th	
		BPM for Rules of Conduct Administration				Complete	
		BPM for Scheduling Coordinator Certification and Termination				Complete, revised version posted Aug 20th	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		BPM for Settlements and Billing	●			Complete, Attachment E posted on Nov 12th. * Going forward, updates and changes to this BPM will be tracked on Criterion STL 1.1.1.	
		BPM - 1.4 **CAISO establishes the BPM Change Management Process; communicates the process to stakeholders; and files the BPM Change Management Process with FERC. The process establishes the procedure that is used to update the BPMs after market launch.**	B	**8/3/07**		- Revised BPM for Change Management Process was posted on June 26. - Information on the Change Management Process can be found at: http://caiso.com/17ba/17baa8bc1ce20.html - FERC Filing over Change Management Process occurred on August 3rd. - Process will go into effect at Go Live. All updates to the BPM Change Management Process as a result of the FERC Technical Conference on Sept 27th have been posted onto the CAISO website as of Nov 15th.	
CRR-1	**CRR**	**CAISO will conduct a market simulation phase, called the Congestion Revenue Right (CRR) Dry Run, to provide market participants and CAISO with the opportunity to step through the process of allocating and auctioning CRRs in a manner that will be similar to the process that will be used to support MRTU implementation.**		**3/30/07**	B		
		CRR - 1.1 **CRR Participants meet the eligibility requirements to participate in the CRR Dry Run.**	B	**8/30/06**			
		1. Participants complete CRR training.	●	**6/29/06**			
		2. Participants receive security digital certificates.	●	**8/30/06**			
		CRR - 1.2 **CRR Participants provide CAISO with valid, annual CRR nominations for the CRR Dry Run.**	B	**8/30/06**			
		CRR - 1.3 **CAISO completes the annual and monthly CRR allocations for the CRR Dry Run.**	B	**2/15/07**			
		1. New CRR Participants meet eligibility requirements.	●	**9/30/06**			
		2. CRR Participants submit CRR nominations to CAISO.	●	**10/15/06**			
		3. CAISO runs the CRR allocation markets and publishes results.	●	**2/15/07**		Annual results of the allocation market were published during 12/06. Monthly results from the allocation market were published on 1/16/07. This Criterion finished early.	
		CRR - 1.4 **CAISO completes the annual and monthly CRR auctions for the CRR Dry Run.**	B	**2/15/07**			
		1. New CRR Participants meet eligibility requirements.	●	**9/30/06**			
		2. CRR Participants submit CRR bids to CASIO.	●	**10/15/06**			
		3. CAISO runs CRR auction markets and publishes results.	●	**2/15/07**		Monthly results of the auction market were published on 1/16/07. Annual results of the auction were published on 1/26/07. This Criterion finished early.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		CRR - 1.5 **CAISO collects the results of the CRR Dry Run, prepares an informational report, and submits it to FERC.**	B	**3/30/07**		Informational Report over Dry Run can be found at: http://www.caiso.com/1bb4/1bb4f3562b4c0.pdf	
CRR - 2	**CRR**	**CAISO will complete the integration testing of the CRR output services. The test results will pass the Quality Review Board review.**		**9/1/08**	B	- All CRR Broadcast Services were successfully triggered to an SOA (Service Oriented Architecture) Bus. - CRR Release 1 successfully passed Quality Review Board FAT and SAT Test review. **August 2008 Update:** Testing for CRR broadcast services to OASIS is complete with 1 outstanding postponed defect regarding GMT timestamp. There is a workaround in place and the GMT timestamp code will be postponed until after the CRR Production Auction market in Nov 2008 Testing CRR broadcast services with SAMC is complete except for CC6798 which should be completed by September. **September 2008 Update:** Integration test of all CRR Broadcast	
CRR - 3	**CRR**	**CAISO will complete the first annual process for allocation of 1-Year CRRs and LT CRRs and for auction of 1-Year CRRs, and first monthly allocation and auction of monthly CRRs.**		**TBD**	P		
		CRR - 3.1 **CRR participants meet the eligibility requirements to participate in the CRR production market.**	B	**10/1/07**			
		1. CRR Participants receive security digital certificates if not already received from CRR Dry Run.		**6/29/07**		All certificates requested by the Participants have been received for allocation.	
		2. CRR System is populated with collateral data from the financial group.		**12/1/07**		The CRR System was populated with collateral data from the financial group on 12/6/07.	
		CRR - 3.2 **The first production run of 1) the annual process for allocation of 1-Year CRRs and LT CRRs, and for auction of 1-Year CRRs; and 2) first monthly allocation and auction of monthly CRRs are complete.**	P	**1/27/09**			
		1. Completion of Annual and Long Term Allocation Process		**12/3/07**		- Tier 1 market: 9/4 - 9/14 - complete - Tier 2 market: 10/5 - 10/9 -complete - Tier LT market: 10/29 - 10/31 - complete - Tier 3 market: 11/21 - 11/27 - complete	
		2. Completion of Annual Auction Process		**12/18/07**		- Annual Auction: 12/11 - 12/13 The Annual Auction Process completed on 12/20/07.	
		3. Start of Monthly Allocation Process		**Exit PPS**			

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		3.1 Complete and post Monthly Allocation results	○	Exit PPS			
		4. Start of Monthly Auction Process	○	Exit PPS			
		4.1 Complete and post Monthly Auction results	○	Exit PPS			
CRR - 4	CRR	**CAISO will make its compliance filing with the FERC's Long-Term Transmission Rights (LT FTR) Final Rule.**		1/29/07	B	Filing can be viewed at: http://www.caiso.com/1845/1845dca750770.html under the name: "CAISO Filing to FERC on Long Term Transmission Rights - 29-Jan-2007"	
ENT - 1	Enterprise Systems	**CAISO will verify that its enterprise systems meet availability requirements. This will be demonstrated by establishing Service Level Agreements (SLAs) for IT support, development, and implementation of monitoring tools and achieving availability requirements during the Pre-Production Simulation (PPS).**		Exit PPS	P		
		ENT - 1.1 **Service Level Agreement (SLA) documents are created and signed off by the MRTU IT Director.**	P	Entry PPS		Initial Drafts completed, turned over to the Operations Information Technology (OIT) team.	
		ENT - 1.2 **Monitoring tools are built into each enterprise system and are used to produce performance and availability reports during PPS market simulation.**	B	Entry PPS		**December 2008 Update** CAISO has developed and implemented monitoring tools for all enterprise systems in NFP. These tools were used in IMS U2 and will continue to be used through parallel operations and PPS.	
		ENT - 1.3 **Each enterprise system meets its minimum availability requirement during the PPS market simulation.**	P	Exit PPS		- Minimum PPS availability cannot be confirmed until PPS phase.	
ECA - 1	External Control Area	**CAISO, market participants, and external control areas agree on the new interchange and e-tagging procedures, being developed as part of the Scheduling and Tagging Next Generation (STiNG) project, including the new Control Area Scheduler (CAS).**		1/23/07	B		
		ECA - 1.1 **100% of tags applicable to CAISO are linked by market reservation to Control Area Scheduler (CAS).**	B	1/23/07		100% of the tags applicable to CAISO from the Participants are being linked through market reservation to CAS.	
		ECA - 1.2 **Control Area Scheduler (CAS) is fully operational and in production.**	B	1/23/07		Control Area Scheduler officially went live on Tuesday, 2/13/07 at 10:00pm.	
GO - 1	Grid Ops	**CAISO grid operating procedures will be created or updated to reflect MRTU implementation. The new and revised grid operating procedures will be reviewed with market participants and external control areas.**		1 Day Prior to Go-Live	P		

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		GO - 1.1 **CAISO Grid Operating Procedures and Emergency Procedures are reviewed. New procedures are created or existing procedures are revised for training purposes to reflect MRTU implementation.**	B	**5/1/08**		Of 352 Operating Procedures: - 83 Operations Procedures have been identified as needing revisions for MRTU. - 47 minor Operating Procedures - 32 significant Operating Procedures will be created or withdrawn. - 4 major Operating Procedures critical for Operations Training. All Operating Procedures are complete: - 4 out of 4 Major Operating Procedures completed. - 32 out of 32 Significant Operating Procedures completed. - 47 out of 47 Minor Operating Procedures completed.	
		GO - 1.2 **CAISO Grid Operating Procedures and Emergency Procedures are provided to Market Participants and External Control Areas.**	B	**5/1/08**		The following are the 4 major operating procedures: - M-401 Day Ahead Market - M-402 Exceptional Dispatch - M-403 Real Time Market - S-326 Southern Cities April Update: All Major Operating Procedures are complete: M-401 Day-Ahead Market M-402 Exceptional Dispatch M-403 Real-Time Market	
		GO - 1.3 **The revised CAISO Grid Operating Procedures and Emergency Procedures are posted on the CAISO website.**	P	**1 Day Prior to Go-Live**		All procedures have been completed and are ready for posting.	
INF-1	**Infrastructure**	**CAISO will meet the MRTU system architecture requirements, including information monitoring processes and tools and availability and stability standards during market simulations.**		**Exit PPS**	P		
		INF - 1.1 **Infrastructure monitoring tools produce logs of system performance and availability during market simulations.**	B	**Exit PPS**			
		1. Weekly up-time reports reflect that system infrastructure is available for at least the time required during each market simulation.		**Exit PPS**		**December 2008 Update:** ISO Monitor and reporting is active on New Production environment and will continue through Go-Live.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		INF - 1.2 **Production environment is available and stable for 7 consecutive days (24 hours a day), excluding approved outages (emergency only), during the market simulations.**	P	**Exit PPS**		The Production environment is available to support Market Simulations. **December 2008 Update:** - Production Environment has been available during Market Simulation.	
		INF - 1.3 **Archive capability is planned, tested, and accomplished in the MRTU infrastructure.**	P	**Exit PPS**		- Archive and Backup work is in progress on the new Production environment	
		INF - 1.4 **Backup/Recovery and Failover/Fallback of MRTU infrastructure is planned, tested, and accomplished.**	P	**Exit PPS**			
		1. Backup/Recovery of MRTU infrastructure is planned, tested and accomplished.		**Exit PPS**			
		2. Failover/Fallback of MRTU infrastructure is planned, tested and accomplished.		**Exit PPS**			
		INF- 1.5 **The final production environment is configured for Go-Live.**	P	**Exit PPS**		The Production environment is available to support Market Simulations. Reconfiguration may occur at the termination of the final Market Simulation in preparation for PPS.	
		INF- 1.6 **Release management processes (framework/structure) are in place prior to PPS market simulation around any changes to the code or production environment.**	B	**Entry PPS**		**October 2008:** Release management process is in place.	
LMP-Testing-1	**LMP Testing**	**CAISO will perform Location Marginal Pricing (LMP) testing. The purpose of LMP testing will be to ensure that the LMP and Ancillary Service Marginal Pricing (ASMP) calculations are accurate using data and results compiled from market simulation activities, analysts track testing, and, to the extent possible, LMP Study 4.**		**Entry PPS**	B		
		LMP Testing - 1.1 **LMP and ASMP Validation in Controlled Test Environment**	B	**7/31/08**		LMP Testing 1.1.1 -1.1.3 combined comments	
		1. LMP for a generating resource, participating load, system resource, and non-participating demand are appropriately (i) equal to, (ii) above, or (iii) below the resources bid, depending on whether the resource schedule is constrained by specific conditions.		**7/31/08**		**October 2008 Update:** Testing of LMP and ASMP validation in the controlled test environment is complete. The final LECG report can be found on the following link: http://caiso.com/2067/2067ea8e50950.pdf	
		2. ASMP for a generating resource, participating load, and system resources are appropriately (i) equal to, (ii) above, or (iii) below the resources Ancillary Service (AS) bid, depending on whether the resource AS schedule is constrained by specific conditions.		**7/31/08**			
		3. Regional Ancillary Service Shadow Prices (RASSPs) are calculated correctly such that: Reg Up Price >= Spin Price >= N-Spin Price, and RASSPs are calculated correctly with AS Cascading activated.		**7/31/08**			
		LMP Testing - 1.2 **LMP and ASMP Validation under Market Simulation Environment**	B	**Entry PPS**		LMP Testing 1.2.1 -1.2.2 combined comments	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		1. LMP for a generating resource, participating load, system resource, and non-participating demand are appropriately (i) equal to, (ii) above, or (iii) below the resources bid, depending on whether the resource schedule is constrained by specific conditions.		**Entry PPS**		- Testing was accomplished with the start of IMS Release 2. - Daily Price Validation Processes for all markets has begun with IMS R3 and conclude prior to the start of PPS. - The goal of this effort is to accomplish comprehensive price validation for all markets within the price correction time horizon (8 days). **August 2008 Update:** CAISO is validating each IFM Market Simulation solution on a daily basis. The CAISO has began including market validation status report information in the daily Market Simulation summary emails to participants in the market trials, and is discussing a weekly summary of these activities each Friday morning as a part of the Market Simulation daily briefing to participants in the market trials **September 2008 Update:** CAISO is validating each IFM Market Simulation solution on a daily basis. Validation of RT cases has also being performed on a daily basis. Currently this includes (a) examination of key indicators of anomalous conditions and results, from which detailed analysis is conducted to identify root causes. **Remaining Steps** While the readiness criteria stated herein is accomplished, CAISO continues to expand and enhance this process to include more automated validation analyses of real timemarkets, and increase the efficiency with which market results are evaluated	
		2. ASMP for a generating resource, participating load, and system resources are appropriately (i) equal to, (ii) above, or (iii) below the resources AS bid, depending on whether the resource AS schedule is constrained by specific conditions.		**Entry PPS**			
LMP-PRD - 1	**LMP Production**	**CAISO will develop and implement the Locational Marginal Pricing (LMP) validation tools, processes, and procedures necessary to support MRTU implementation.**		**11/1/08**	B		

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		LMP Production - 1.1 **The LMP tool is operational and 100% of processes and procedures are completed.**	B	**11/1/08**		**August 2008 Update:** Work continues on the SAS code, with frequent updates from LECG. IT and Market Ops have completed performance tests of the tool in the production environment and are analyzing the results. Work continues on the output viewer, and SAS consultants have been given requirements for the Kick Off controller. **October 2008 Update:** Significant progress has been made with the remaining work focused on the output viewer. It is anticipated that the tool will be completed by early November. **November 7,2008 Update:** Work on the output viewer has been accomplished and the LMP Tool is now complete.	
MKS - 1	**Market Services**	**CAISO will prepare an assessment of the MRTU market systems' effectiveness when responding to instances where the demand bids exceed the supply bids and post on the CAISO website.**		**Exit Update 2**	B	**October 2008 Update:** This Readiness Criterion is reflected in Scenario 10 of the IMS Scenario Executions. This scenario ran for trade date 9/20/08 and the preliminary results are available for Market Participant review. http://www.caiso.com/204e/204e785f5d30 0.pdf. **November 7, 2008 Update:** Based on the observed market results, the objective of this shortage of supply scenario was achieved. The Final Report is posted on the CAISO website on the following link: http://www.caiso.com/2076/2076dd7b34a 0.pdf	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
MKS - 2	**Market Services**	**CAISO will develop post implementation evaluation criteria, including MRTU performance and operational issues, collaboratively with stakeholders for inclusion in CAISO's post-implementation performance reports.**		**7/31/08**	B	Two Stakeholder meetings have been held to identify the type criteria that would be included on post implementation reports. The CAISO has developed a set of MRTU Market Performance Metrics to be used in the Post Implementation evaluation report. These metrics can be found on the CAISO website on the following link: http://www.caiso.com/179d/179ddbce22760.html. The CAISO is working on compiling the list of post-evaluation criteria and will post it onto the CAISO website. **July 2008 Update:** The CAISO is in the final stages of finalizing the list of reporting metrics for the Post Implementation quarterly report.. Note: The target date was changed to reflect additional items to complete in the reporting metrics. **September 2008 Update:** The CAISO has established post implementation reporting metrics to be filed on a quarterly basis 30 days after the	
MS - 1	**Market Systems**	**CAISO will create support, monitoring, and availability requirements for the MRTU market systems, including the establishment of Build Documents, Run Books and application monitoring tools.**		**Exit PPS**	P		
		MS - 1.1 **Build Documents and Run Books are created and signed off.**	P	**Entry PPS**		Process for creating Build Docs and Run Book requirements in progress.	
		MS - 1.2 **Monitoring tools are integrated and functioning in each Market System and are used to produce performance and availability logs during the Pre-Production Simulation (PPS) market simulation phase.**	P	**Entry PPS**		Application monitoring in progress **November 2008 Update:** ISO Monitor is active on new Production environment, additional monitoring being added.	
		1. The monitoring tool is integrated with the Settlement and Market Clearing (SaMC) system.		**Entry PPS**		Application monitoring in place.	
		2. The monitoring tool is integrated with the Client Management Repository (CMRI) system.		**Entry PPS**		Application monitoring in place.	
		3. The monitoring tool is integrated with the Scheduling Infrastructure Business Rules (SIBR) system.		**Entry PPS**		Application monitoring in place.	
		4. The monitoring tool is integrated with the Integrated Forward Market (IFM) system.		**Entry PPS**		Application monitoring in place.	
		5. The monitoring tool is integrated with the Real-Time Market (RTM) system.		**Entry PPS**		Application monitoring in place.	
		6. The monitoring tool is integrated with the Portal system.		**Entry PPS**		Application monitoring in place.	
		7. The monitoring tool is integrated with the Market Quality System (MQS) system.		**Entry PPS**		Application monitoring in place.	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		MS - 1.3 Each Market System has met its minimum availability requirement during the PPS market simulation phase.	P	**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		1. The SaMC system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		2. The CMRI system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		3. The SIBR system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		4. The IFM system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		5. The RTM system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		6. The Portal system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
		7. The MQS system meets minimum availability requirement.		**Exit PPS**		Hardware and monitoring tools deployed to measure availability during PPS.	
MM - Study - 1	**Market Monitor Study**	**CAISO will complete the Final Competitive Path Assessment (CPA) after thorough review and input from stakeholders; allowing the resulting path designations to be posted to the CAISO website.**		**30 days prior to Market Launch**	P	The first set of preliminary results were published on the CAISO website under the heading "MRTU Competitive Path Assessment White Paper": A second set of preliminary CPA results was published on 10/1/07. Both reports and all other CPA information can be found at: http://www.caiso.com/docs/2005/07/01/200507011120583480.html. Third set of preliminary CPA results were published on 12/19/07 under the heading: CPA for MRTU Release 3 of Preliminary Results. This report can be found at: http://www.caiso.com/docs/2005/07/01/200507011120583480.html. **December 2008 Update:** The Final CPA report is being developed and will be published not less than 30 days prior to go-live.	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
MM - Study - 2	Market Monitor Study	The issue raised by LECG about a potential deficiency in the preferred Local Market Power Mitigation (Direct Mitigation) will be evaluated and will be determined not to be a significant concern.		12/31/06	B	There is no indication that the LECG concern was valid for the LMPM approach that we are taking, and therefore, is not a significant concern. Report on LMPM deficiency can be found at: http://www.caiso.com/docs/2004/10/01/2004100110503422982.html	
SIM - 1	Market Simulation	In advance of each of the market simulations, CAISO, with input from stakeholders, will establish entry and exit criteria. The entry and exit criteria will be posted on the CAISO website. The entry and exit criteria from each Market Simulation will be met.		Exit PPS	P		
		SIM - 1.1 The Rules Validation / Connectivity Simulation (RV/CS) phase entry and exit criteria are met.	B	Exit RV/CS		RV/CS Scorecard can be found at: http://www.caiso.com/18d2/18d2926739ba0.pdf	
		SIM – 1.2 The Enhanced Rules and Connectivity Inter – SC Trade (ERC-IST) simulation phase entry and exit criteria are met.	B	Exit ERC-IST		ERC/IST Scorecard can be found at: http://www.caiso.com/1bbe/1bbed8903a0f0.pdf	
		SIM – 1.3 The Integrated Market Simulation (IMS) entry and exit Criteria are met.	B	Exit R2			
		SIM 1.3.1 Release 1 The Integrated Market Simulation (IMS) Release 1 (R1) entry and exit criteria are met.	B	Exit R1		R1 successfully exited on 5/18/07. R1 entry and exit criteria can be found in the "Market Simulation Criteria Tracker" at: http://www.caiso.com/186a/186acdf53cdf0.html The R1 Scorecards can be found at: http://www.caiso.com/1bb6/1bb674bb18c90.html	
		SIM 1.3.2 Release 2 The Integrated Market Simulation (IMS) Release 2 (R2) entry and exit criteria are met.	B	Exit R2		R2 concluded on 7/20/07. R2 entry and exit criteria can be found in the "Market Simulation Criteria Tracker" at: http://www.caiso.com/186a/186acdf53cdf0.html R2 Weekly Report Cards can be found at: http://www.caiso.com/1bb8/1bb8c03d28380.html	
		Sim 1.4 Release 3 IMS Release 3 Entry and Exit Criteria as identified in the Market Simulation Guide Book are complete with the exit of IMS Update 2.	B	Exit Update 2			
		SIM 1.4.1 Release 3 Integrated Market Simulation Release 3 begins.	B	Exit R3		- IMS Release began on 9/24/07. - IMS R3 URL Document, Charge Code, and other information can be found at: http://www.caiso.com/1bd7/1bd7ebbc72fc0.html IMS Release 3 concluded on 11/9/07.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		SIM 1.4.2 Update 1 **Integrated Market Simulation Update 1 begins.**	B	**Exit Update 1**		IMS Update 1 began on 11/13/07. -IMS Update 1 URL Document, Charge Code, and other information can be found at: http://caiso.com/1c2d/1c2d9ced4aa60.html	
		SIM 1.4.3 Update 2 **Integrated Market Simulation Update 2 begins and concludes with all Exit criteria as identified in the Market Simulation Guide Book complete.**	B	**Exit Update 2**		IMS Update 2 began on 02/19/08. -IMS Update 2 URL Document, Charge Code and other information can be found at : http://caiso.com/1c96/1c96acdd1d710.html **December 2008 Update:** IMS U2 concluded. Discussion of the completion of IMS U2 can be found in the	
		Sim – 1.5 **The Pre-Production Simulation (PPS) entry and exit criteria are met.**	C	**Exit PPS**			
MOD-1	**Model**	**CAISO will complete all updates to the Full Network Model. (FNM)**		**10/31/08**	B		
		MOD - 1.1 **FNM updates are completed (except for simultaneous promotion of Markets and EMS to production) utilizing integrated databases or approved workarounds.**	B	**6/30/07**		**October Update:** The FNM has been updated in the FIT environment and is scheduled to be included in the next phase of Market Simulation. All future model updates are planned to be promoted into the MRTU Market Simulation.	
		MOD - 1.2 **FNM updates are completed (including simultaneous promotion of Markets and EMS to production) utilizing integrated databases or approved workarounds.**	B	**10/31/08**		**December2 008 Update:** Full integration of the FNM model DB38 was successfully completed with no process issues.	
ORG - 1	**Organizational Readiness**	**CAISO's organizational readiness tasks will be completed and the Core Business Units affirm their successful completion. Readiness tasks may include the following elements, as applicable:** **1. Organizational Impact Assessment** **2. Job Analysis and Design** **3. Organizational Analysis and Design** **4. Communication Plan** **5. Knowledge Transfer Plan** **6. Revised Job Descriptions** **7. Revised Contingency Plan** **8. Tools, Processes, and Procedures** **9. Training**		**60 Days Prior to Market Launch**	P	**December 2008 Update:** Core Business Units continue to be involved in current testing activities (Operations, IT). All Tier 1 Business Processes have been signed off. Application transition and sign off have been completed. Business Units continue to track remaining Go-Live activities.	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
ORG - 2	Organizational Readiness	CAISO's organizational readiness tasks will be completed and the Non-Core Business Units affirm their successful completion. Readiness tasks may include the following elements, as applicable: 1. Organizational Impact Assessment 2. Job Analysis and Design 3. Organizational Analysis and Design 4. Communication Plan 5. Knowledge Transfer Plan 6. Revised Job Descriptions 7. Revised Contingency Plan 8. Tools, Processes, and Procedures 9. Training		60 Days Prior to Market Launch	B	**January 2009 Update:** All MRTU tasks for Non-Core Business Units are completed, the final needed activity for the BU has been completed.	
ORG - 3	Organizational Readiness	CAISO will establish the tools and environments required to support the market monitoring, enforcement, and compliance functions.		60 Days Prior to Market Launch	P		
		ORG - 3.1 All data identified by the Department of Market Monitoring (DMM) Unit as critical for market monitoring will be stored in an organized relational database, thoroughly documented, and will be made available to the Department of Market Monitoring Unit.	P	60 Days Prior to Go-Live		• Enterprise Data Repository (EDR): Project is near completion for critical (to DMM) six market applications, and further enhancements have been made by EDR Team. Issues still exist with representation of Master File data, DEB input data, and expanded transmission data. None of these are critical matters for go-live. • Initial draft of Data Dictionary is available, but documentation is dated and incomplete, making this source of information of limited use. Need updates from vendors and assignment of data dictionary custodianship (definitions and data dictionary application) to individuals / business unit before Go-Live. Most data availability issues have been either resolved or are being addressed through change requests and work-around. DMM is actively working with EDR and MRTU PMO to get remaining issues resolved prior to go live. At this time it does not appear that there are any	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		ORG - 3.2 **A core set of monitoring tools (software, indices, and reports) will be completed and functional.**	P	**60 Days Prior to Go-Live**		**December 2008 Update:** Over the next several months DMM will continue refining its core metrics and developing additional metrics to enhance its monitoring capabilities.	
		ORG - 3.3 **A Market simulation tool (the MRTU Sandbox / DMM Tool) that is based on the actual CAISO market software will be developed and tested by the CAISO MRTU Team and made available to the Department of Market Monitoring (DMM) Unit three months prior to Go Live.**	P	**90 Days Prior to Go-Live**		January 2008 Update: • DMM Sandbox is on site and is being used by DMM. • Reliability issues are being addressed, along with software versioning and save-case access. • DMM is working closely with IT and MRTU PMO on issue resolution. Continued focus and resources will be devoted to assure the DMM tools are working properly and are adequate for go live. Weekly status is being reported and reviewed by CAISO Management on progress and resolution of items.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
PRT - 1	Participant Readiness	CAISO will monitor the "readiness" of the market participants through a series of MRTU Readiness Assessments to assist in ensuring that at least 80% of the active CAISO market participants including those that meet significant CAISO demand requirements are "Ready" prior to market launch. The assessment criteria will include people, process, and technology areas of readiness.		30 Days Prior to Market Launch	P	December 2008 Update: The CAISO is working closely with Market Participants with their readiness plans. Progress in settlement validation is occuring and parallel operations will provide additional opportunities to ready Market Participants' staff.	
		PRT - 1.1 80% of the market participants including those that meet significant CAISO demand requirements complete the Initial Baseline Assessment.	B	1/31/07		81% of Market Participants including those that meet significant CAISO demand completed their assessments.	
		PRT - 1.2 80% of the market participants including those that meet significant CAISO demand requirements complete the First Follow-Up Assessment.	B	7/31/07		100% of Market Participants completed their assessments.	
		PRT - 1.3 80% of the market participants including those that meet significant CAISO demand requirements achieve a "READY" score on Final Assessment.	C	30 Days Prior to Market Launch		The CAISO will be conducting the Final Assessments in February 2009	
PRT - 2	Participant Readiness	CAISO will monitor and record overall issues during each Release (and update) of Integrated Market Simulation (IMS), resolve any issues that hinder meeting the pre-defined release objectives and all for Market Participant testing time.		Exit R3 Update 2	B		
		PRT - 2.1 Release 2 - Resolution of all high priority issues that hinder the pre-defined release objectives and allow for Market Participant testing time.	B	Exit R2		- Settlement files to-date have not met Market Participant expectations and requirements for testing. - All R2 in-scope activities are not yet available. - R2 Simulation concluded without simulation success from a product testing and business process point of view. - There were two High+ issues that prevented participants from meeting the objectives for Release 2. There were also two High+ issues with Market Test status. IMS R2 was concluded. The Market Simulation team and the PMO are currently discussing steps to resolve the open issues.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		PRT - 2.2 **Release 3 (includes Updates 1 & 2) - Resolution of Critical and Very High priority issues that hinder the pre-defined release 3 objectives and allow for Market Participant testing time.**	B	**Exit Update 2**		All Critical and Very High issues are being resolved as they arise. A weekly Status and Issue report is posted on the CAISO website at : http://www.caiso.com/1bd7/1bd7ebbc72fc0.html#1c6011d9c6cd70. **December 2008 update:** All issues that prevented Market Participants from participating in Market Simulation were address immediately. Based on the weekly participation report cards, a very high percentage of Scheduling Coordinators were actively testing in Market Simulation, therefore, no issue hindered participation in IMS U2.	
REG - 1	**Regulatory**	**CAISO's MRTU regulatory requirements will be completed, including tariff updates and filings.**		**60 - 90 days prior to go-live**	B		
		REG - 1.1 **CAISO completes tariff updates and other necessary filings such as additional non- substantive compliance or 205 filings (e.g. clean ups, deferred maintenance, merger of S&R tariff amendments into MRTU (e.g. Credit policy)) and files them with FERC.**	B	**60 - 90 days prior to go-live**		**January 2009 Update:** As of January 16th all known non-substative filings have been made.	
		REG - 1.2 **BPM updates are consistent with MRTU tariff and applicable FERC orders.**	B	**60 - 90 days prior to go-live**		Revised BPMs were posted on November 15 consistent with FERC orders and MRTU Tariff on file. Additional proposed tariff language were also filed on November 15. The CAISO has satisfied BPM-related FERC directives.	
		REG - 1.3 **All substantive compliance filings and substantive 205 filings are filed with FERC.**	B	**180 Days Prior to Market Launch**		On 8/3/07, all compliance items that required filing no later that 180 days prior to Go Live from the 9/21, 4/20, and 6/25 FERC Orders, were submitted to FERC. -The initial scope of this criterion was satisfied on 8/3/07. An extension on two filings (LAP Clearing, and RA Backstop) in scope for this criterion will be tracked on criterion REG - 1.1.	

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
SE - 1	State Estimator	The purpose of the State Estimator (SE) criteria is to provide a measurement to evaluate the stability of the SE system and solution for MRTU. This category will monitor the State Estimator performance, voltage accuracy, and difference from telemetered flows on tie lines and branches that are within a predefined criteria: 1. SE solution must be achieved for 97% of five minute periods within a 30 day period. 2. SE voltage must be within 2% of metered voltage on 50 critical buses. 3. SE MW flow must be within 50MW or 5% of telemetered flow on 10 tie lines to outside CAISO. 4. SE flows on transmission lines and transformers must be within 10% of telemetered flows on all other branches within the CAISO footprint.		6/1/07	B		
		SE - 1.1 Real-Time Performance Criteria – For thirty (30) consecutive days a Valid State Estimator solution is achieved for ninety-seven percent (97%) of the five (5) minute periods within that thirty (30) day period. There are no more than three (3) consecutive five (5) minute periods without a valid solution (except when there is a planned system software migration as required by the Energy Markets project or when ICCP data is unavailable due to remote CA ICCP node errors). Valid solution are defined as one converged solution in a 5 minutes period using converge tolerance of 10 MW/ MVAr and maximum 'Zero-Injection' bus mismatch of 25 MW/MVAr inside the State Estimator solution within the California ISO Market footprint.	B	6/1/07		Criteria is complete	
		SE - 1.2 On fifty (50) buses where voltage is deemed critical, the solved State Estimator voltage is within two percent (2.0%) +/- accuracy of the metered voltage, provided that the metered voltage is measured to within the notified accuracy. The fifty (50) critical buses are defined by the California ISO with Transmission Owner input and include at least one bus in each control area that is inside the observable California ISO market footprint. All buses (elements) are inside the observable California ISO Market model.	B	6/1/07		Criteria is complete	
		SE - 1.3 On ten (10) tie lines to outside of the California ISO System, the absolute difference between the telemetered flow and the State Estimator MW flow is within fifty (50) MW or five percent (5%) for lines 100kv and above, of the base rating. The ten (10) tie lines are defined by California ISO, with Stakeholder input. All tie lines (elements) are inside the observable California ISO Market model.	B	6/1/07		Criteria is complete	
		SE - 1.4 On all other branches (>100kV) within the California ISO footprint, the absolute difference between the telemetered flows and the State Estimator flows on transmission lines and transformers are within ten percent (10%) of the base rating. All other branches (elements) are inside the observable California ISO Market model.	B	6/1/07		Criteria is complete	
STL- 1	Settlements	CAISO will complete a Settlement and Market Clearing (SaMC) audit. The purpose of the audit will be to ensure that the SaMC software performs as defined in the CAISO MRTU Tariff.		1 Day Prior to Market Launch	P		
		STL - 1.1 CAISO completes the following activities to ensure consistency:	B	Entry PPS			

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		1. Validation that the BPM for Settlements & Billing is consistent with the requirements that are identified in the CAISO MRTU Tariff.		Entry PPS		**October 2008 Update:** The Settlements BPM is consistent with the requirements that are identified in the CAISO MRTU Tariff. The Settlements BPM and its attachments can be found on the following link: http://www.caiso.com/17e9/17e97b196bd30.html *Please note that the Settlements BPM is a living document and updates will be made to it as needed.	
		2. Validation of the consistency between the Settlement BPM and the SaMC design documents.		Entry PPS		**October 2008 Update:** The Settlements BPM is consistent with the SaMC design documents. *Please note that the Settlements BPM is a living document and updates will be made to it as needed.	
		STL - 1.2 **An audit by an independent firm that validates the consistency of the SaMC software with the CAISO tariff is completed per the tariff timeline.**	P	**1 Day Prior to Market Launch**		**November 2008 Update:** The audit is scheduled to be completed by early December 2008.	
STL- 2	**Settlements**	**CAISO will test and implement its final settlement charge code configuration. The final configuration must include required changes from market simulation activities, the Grid Management Charge (GMC), and any changes arising from the 9/21/06, 4/20/07, 5/8/08, 6/25/07, and 7/6/07 FERC Orders.**		Entry PPS	P	**December 2008 Update:** The CAISO continues to work with Market Participants with settlement charge code validations. The "Daily Charge Code Status" is posted on the website at: http://www.caiso.com/1c2d/1c2d9ced4aa60.html#1caacdff53ca0 Market Participants have reported that they are able validating charge codes and should be ready by go-live.	
STL- 3	**Settlements**	**CAISO will publish accurate and complete settlement statements and invoices during Update 2 of the Integrated Market Simulation phase. The published statements and invoices will be consistent with market participants activities during Update 2 of the Integrated Market Simulation phase.**		Exit Update 2	P	**December 2008 Update:** The CAISO continues to work with Market Participants with settlement charge code validations. The "Daily Charge Code Status" is posted on the website at: http://www.caiso.com/1c2d/1c2d9ced4aa60.html#1caacdff53ca0 Market Participants have reported that they are able validating charge codes and should be ready by go-live. Mini-monthly statements have been published to help in monthly validations.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
TECH - 1	Technology	The Technical Operational Readiness Testing (ORT) exit criteria will be satisfied and approved by the CAISO Business Owners and the Director of MRTU IT. ORT exit criteria will include: 1. Successful completion of high availability testing. 2. Fault tolerance and failover/fallback testing. 3. Load and Performance Testing.		Entry PPS	P		
TST - 1	Testing	Performance Testing criteria for the IMS Releases 1-2 and Release 3 (including Updates 1 and 2) of Market Simulation will be met as defined in the Performance Test approach document.		Entry Update 2	B		
		TST - 1.1 Performance Testing entry and exit criteria are met for Release 1 of the Integrated Market Simulation.	B	Entry R1		R1 Performance testing is completed and has passed QRB review.	
		TST - 1.2 Performance Testing entry and exit criteria are met for Release 2 of the Integrated Market Simulation.	B	Entry R2		R2 Performance testing is completed and has passed QRB review.	
		TST - 1.3 Performance Testing entry and exit criteria are met for Release 3 of the Integrated Market Simulation.	B	Entry R3		R3 Performance testing is completed and has passed QRB review.	
		TST - 1.4 Performance Testing entry and exit criteria are met for Update 1 of Market Simulation.	B	Entry Update 1		The CAISO has performed Performance testing needed to enter into IMS Update 1. As a result, this criterion is marked as 'Complete"	
		TST - 1.5 Performance Testing entry and exit criteria are met for Update 2 of Market Simulation.	B	Entry Update 2		Update 2 Performance testing is completed and has passed QRB review. **November 7, 2008 Update:** Due to recent systems performance in IMS U2, Performance Testing is in progress to resolve current issues. **November 30, 2008 Update:** The CAISO continues to monitor systems performance and tests will be conducted as necessary. However, for the purposes of this Readiness Criteria, Performance testing has passed QRB review prior to the entry into IMS Update 2, therefore, this criterion is considered complete.	
TST - 2	Testing	Integration Testing criteria for the IMS Releases 1-2 and Release 3 (including Updates 1 and 2) of Market Simulation will be met as defined in the Performance Test approach document.		Entry Update 2	B		

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
		TST - 2.1 **Integration Testing entry and exit criteria are met for Release 1 of the Integrated Market Simulation.** *** This is integration testing to get into Market Simulation.**	B	**Entry R1**		R1 Integration testing is completed and has passed QRB review.	
		TST - 2.2 **Integration Testing entry and exit criteria are met for Release 2 of the Integrated Market Simulation.** *** This is integration testing to get into Market Simulation.**	B	**Entry R2**		R2 Integration testing is completed and has passed QRB review.	
		TST - 2.3 **Integration Testing entry and exit criteria are met for Release 3 of the Integrated Market Simulation.** *** This is integration testing to get into Market Simulation.**	B	**Entry R3**		R3 Integration testing is completed and has passed QRB review.	
		TST - 2.4 **Integration Testing entry and exit criteria are met for Update 1 of Market Simulation.** *** This is integration testing to get into Market Simulation.**	B	**Entry Update 1**		Update 1 Integration Testing is completed and has passed QRB review.	
		TST - 2.5 **Integration Testing criteria are met for Update 2 of Market Simulation.**	B	**Entry Update 2**		**November 2008 Update:** Core integration testing has been completed for IMS Update 2; therefore, this criterion is considered complete. However, internally, additional integration testing may be performed when needed to support system patches that were identified during IMS Update 2. This activity is maintained through the change management process.	

MRTU Readiness Criteria Dashboard

Readiness Criterion Identifier	Readiness Category	Readiness Criterion	Criterion Component Status	Target Due Date / Market Simulation Phase	Overall Category Status	Documentation and Comments	Issues and Mitigating Actions
BUS- BA - 1		All MRTU systems will meet the business requirements and pass the Business Unit review. Acceptable manual workarounds will be identified for systems that do not satisfy the required business functions. 1. The Settlement and Market Clearing (SaMC) system will pass Business Unit review. 2. The Scheduling Infrastructure Business Rules (SIBR) system will pass Business Unit review. 3. The Integrated Forward Market (IFM) system will pass Business Unit review. 4. The Real-Time Market (RTM) system will pass Business Unit review. 5. The Operational Meter Analysis and Reporting (OMAR) system will pass Business Unit review. 6. The Master File will pass Business Unit review. 7. The Open Access Sametime Information System (OASIS) system will pass Business Unit review. 8. The Participant Intermittent Resource Program (PIRP) system will pass Business Unit review. 9. The Automated Dispatch System (ADS) system will pass Business Unit review. 10. The Reference Level Calculator (RLC) system will pass Business Unit review. 11. The Existing Transmission Contract Coordination (ETCC) system will pass Business Unit review. 12. The Compliance Automation Production System (CAPS) will pass Business Unit review 13. The Scheduling and Logging in California (SLIC) system will pass Business Unit Review. 14. The Market Quality System (MQS) system will pass Business Unit Review. 15. The Control Area Scheduling (CAS) system will pass Business Unit Review. 16. The Automated Load Forecast System (ALFS) will pass Business Unit Review. 17. The RMR Automated Validation Engine (RAVE) will pass Business Unit Review. 18. The Full Network Model (FNM) will pass Business Unit Review. 19. The PTR will pass Business Unit Review. 20. The Energy Management System (EMS) will pass Business Unit Review. 21. The Market Definition Service (MDS) system will pass Business Unit Review. 22. The Congestion Revenue Rights (CRR) system will pass Business Unit Review.		60 days prior to go - live	P	**November 2008 Update:** All application transition sign-offs have been completed. Acceptable manual workarounds have been identified for systems that do not satisfy the required business functions. However, as further testing of the applications continue, additional manual workarounds will be developed if needed.	
BUS- BA - 2	Business Approval - Business Area	CAISO will submit to FERC its readiness certification based upon the following information: 1. Review of all readiness criteria 2. All Market Participant input through the assessment process 3. Resolution of critical high issues 4. Completion of cutover and reversion plans 5. Completion of contingency plans 6. Completion of cutover walkthrough 7. 60 Day Plan		60 days prior to go - live	B	The readiness certification was filed on January xx, 2009.	

ATTACHMENT 9

California Independent
System Operator Corporation

Review of California ISO MRTU
Structured Market Simulation Results
Trade Days - December 9-12, 2008

Department of Market Monitoring

January 16, 2009

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I. Executive Summary

This report provides a follow-up assessment of certain market performance issues raised by the California Independent System Operator Corporation (CAISO) Department of Market Monitoring (DMM) in its October 22, 2008, report (October Report) assessing the results of the market redesign and technology upgrade (MRTU) market simulations during September 2008.[1]

Based on this follow-up analysis, DMM believes the MRTU markets have performed reasonably well overall in the structured market simulations performed in December, and we have not seen any performance issues that would warrant a delay in MRTU implementation. However, we do recommend that the CAISO continue to work with DMM and market participants over the next six weeks to conduct a more in-depth assessment of some of the more extreme pricing outcomes in the December structured simulations to better explain and confirm the root cause of these results. Additionally, we recommend the CAISO closely track and mitigate the root cause of potential failures that have periodically prevented the running of local market power procedures prior to the Real Time Market, and establish pricing provisions when such failures occur under actual market operation.

Summary of October DMM Report

In the October Report, we identified five specific areas for further review and analysis:

1. **Extreme real-time market locational marginal prices (LMPs) –** Our assessment of the real-time market (RTM) performance in September found that roughly 2 percent of the real-time market clearing quantities cleared at LMPs greater than $1,000/MWh. A significant share of these extreme prices were reviewed by the CAISO and found to be due to software or technical glitches in the simulation environment that have since been corrected. DMM recommended that the CAISO continue conducting in-depth analysis of the root cause of extreme LMPs to identify and correct any erroneous modeling or software issues that may be causing these prices.
2. **Price divergence between day-ahead and real-time markets –** Our analysis of September market simulation results found that prices for imports and exports on inter-ties with other control areas tended to be significantly higher in the Real Time Market than in the Day Ahead Market. This divergence was part of a more general trend of much higher prices in the real-time market. We noted that if such significant and systematic price divergences persisted under MRTU, it could result in market inefficiencies and potential implicit virtual bidding at the inter-ties. We recommended the CAISO run structured market scenarios to further examine and test for price divergences between the Day Ahead and Real Time Markets.
3. **Reliance on non-resource adequacy units in the residual unit commitment (RUC) process –** Results from the September market simulations showed that the RUC process consistently awarded RUC capacity to non-resource adequacy units at fairly high average RUC prices. An effective resource adequacy program should generally provide sufficient

[1] The October Report can be found on the CAISO website at: http://www.caiso.com/2068/2068ad206a9b0.pdf

capacity in RUC such that reliance on non-RA units is minimal; therefore, RUC prices would generally be low if not zero. If non-RA resources are routinely awarded large amounts of RUC capacity at relatively high prices in actual market operation, this could have significant market power and price distorting implications for other markets that would in our view necessitate changes to the RUC market design and/or market power mitigation rules. We committed to undertake additional analysis to better assess whether sufficient resource adequacy (RA) capacity is being offered to the day-ahead market.

4. **Effectiveness of local market power mitigation (LMPM) –** Our analysis of the September market simulations found that the LMPM procedures appear to be working as intended and are effectively mitigating local market power. However, we indicated that we would continue to review LMPM performance.
5. **Skipped or Failed LMPM Procedures -** Importantly, our September analysis found that the LMPM procedures fail to run in the real-time market or have been skipped in as much as 5 percent of the hours. We committed to continue to monitor the frequency of any failures of RTM market power mitigation runs during market simulation, and recommended that these failures be formally tracked by the CAISO as a basic market performance metric.

In response to the DMM recommendations, as well as similar requests from market participants, the CAISO completed a structured market simulation for trade days December 9-12.[2] We used the results from these structured simulations to further assess the five issues noted above. A summary of the key finding from our updated assessment of these issues is provided below.

Summary of Structured Simulation Findings

Residual Unit Commitment (RUC)

More recent market simulation results – including the structured market simulations discussed here – show much smaller amounts of RUC capacity being awarded to non-RA capacity and in much fewer hours. Moreover, the RUC prices paid for this capacity are generally moderate. Consequently, we are less concerned about this issue and do not believe that any changes in the RUC design are necessary prior to MRTU go-live. We will be closely monitoring the performance of the RUC market after go-live. We also strongly encourage the load-serving entities (LSEs) to mitigate reliance of non-RA resources in RUC through proactively managing their RA portfolio to ensure sufficient RA capacity is being made available to the CAISO Day Ahead Market.

Finally, we also recommend that the CAISO consider alternatives to the current RUC design for implementation after MRTU go-live. Importantly, we believe the current RUC design may be incompatible with nodal convergence bidding. As the CAISO works towards finalizing its convergence bidding market design it should consider the implications and compatibility of that design with RUC – among other things.

[2] In November, the CAISO initially tried to perform structured base-case analysis separate from the market simulations but this approach proved to be difficult to complete for the hour-ahead scheduling process (HASP) and Real Time Market. Consequently, an alternative approach was adopted in December.

Real Time Market Performance – Extreme Prices & Price Convergence

The structured market simulations performed in December were designed to assess both the frequency and root cause of extreme real-time prices and price convergence. However, while the structured market simulations in December were of better quality in terms of the submitted bids and schedules and constructed scenarios, they were far from perfect and ultimately suffer from the unavoidable fact that until real dollars are at stake, market participants are not going to exert the level of thought and effort and reaction to observed prices that they would in actual market operation. Consequently, we remain cautious in inferring too much from these simulations. With this caveat, our general assessment of the December structured market simulations is that they produced – in most hours – more realistic and explainable real-time market outcomes.

- With the exception of December 12, extreme real-time market prices were less frequent than observed in the September simulations but still need further analysis to understand their root causes. The CAISO is currently working with DMM and market participants in undertaking a deeper analysis of a subset of extreme prices observed in the structured market simulation.

- Extreme real-time market prices observed on December 12 appear to be due to a combination of reduced supply bids and increased demand, the combination of which resulted in severe system shortages. We do not consider the structured scenario for this day to be very realistic and the extreme results observed are more reflective of the limitations of the simulation as opposed to what we would expect in actual market operation. Specifically, if the CAISO experienced such a significant increase in real-time energy demand in actual operation on a peak summer day, we believe that there would be a significant market response of increased supply, particularly at the inter-ties, which would mitigate extreme prices, whereas the structured simulation had essentially no supply response. Moreover, such an extreme event would likely trigger demand response programs, which did not happen under the structured simulation. The extreme prices observed in the simulation for this day appear to reflect various transmission constraint violations. However, we recommend that the CAISO closely examine a sample of these extreme prices to confirm their root cause.

- Day-ahead and real-time load aggregation point (LAP) prices generally showed better price convergence than observed in the September simulations, particularly during shoulder hours of the day. Real-time prices during the peak hours were still fairly volatile and higher than day-ahead prices but this likely has more to do with deficiencies in the simulation environment than some systematic bias or problem in the market software.

- Prices at the inter-ties also generally showed better convergence than observed during the September simulations – though not at a level that we would expect under actual market operation. As expected, prices at the inter-ties generally diverged more under the load under-scheduling scenario that was executed on December 10.

Effectiveness of Local Market Power Mitigation Procedures

The structured market simulation scenario for the December 11 trade date was specifically designed to test the effectiveness of local market power mitigation (LMPM) procedures. Under this scenario, bids for a significant portion of capacity within several transmission-constrained areas were set at relatively high prices in order to test LMPM performance. The results of this single scenario indicate that LMPM mechanisms are functioning as designed in the integrated forward market (IFM) and effectively mitigating market power. However, DMM plans to further "stress test" LMPM procedures in both the IFM and HASP/RTM through off-line market simulations.

While our review indicates that LMPM mechanisms functioned properly during all of the structured market simulation scenarios, results of the December 11 scenario for the San Diego area highlight the importance of making sure that sufficient time is provided for the IFM to reach an optimal solution – even if that means significantly delaying the close of the Day Ahead Market. Specifically, on the December 11 scenario, although one of the key criteria for measuring the quality of IFM solution (or "MIP Gap"[3]) was not met, the Day Ahead Market was closed in order to provide market participants with sufficient time to structure and submit real-time bids. Under this less optimal solution, a Reliability Must Run (RMR) unit within San Diego that was committed in the market power mitigation procedures was not committed in the IFM. As a result, LMPs within the San Diego area during the peak hours of this scenario exceeded $500/MW (compared to mitigated bid prices of less than $100/MW).

The CAISO subsequently re-ran the same IFM scenario (with an off-line version of the IFM software) and provided additional time to reach a better solution. Under this more optimal solution, one additional RMR unit was dispatched in the San Diego region, and LMPs were lowered to levels reflecting mitigated bids. We recommend that in the event a similar situation should occur under actual market operations, the CAISO should be prepared to extend the solution time of the market software and re-run the software prior to closing the IFM.

Finally, as noted in our October Report, DMM found that the Real Time Market LMPM procedures failed to run or were skipped in as much as 5 percent of the hours during the September simulations. Such failures are generally caused when the software fails to reach a solution in the required amount of time. DMM's review of market simulation logs for December indicates that these failures continue to be occurring in about 5 percent of hours. Thus, we are again recommending that the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. In addition, DMM has recommended that the CAISO establish pricing provisions that may be applied in cases where the LMPM procedures are not completed in the Real Time Market in actual market operation.

Summary

In summary, this updated analysis of the structured simulations has largely addressed the five issues identified in our October Report. Overall, the MRTU markets have performed reasonably well in the structured market simulations and we have not seen any performance issues that would warrant a delay in MRTU implementation. However, we do recommend that the CAISO continue to work with DMM and market participants over the next six weeks to conduct a more in-depth assessment of some of the more extreme pricing outcomes in the December structured simulations to better explain and confirm the root cause of these results. Additionally, we recommend the CAISO closely track and mitigate the root cause of market power mitigation

[3] For an explanation of the "MIP Gap" metric used to assess the optimality of the market solution, see page 82 of this report.

failures in the Real Time Market and establish pricing provisions when such failures occur under actual market operation.

II. Overview

This report provides a follow-up assessment to certain market performance issues raised by DMM in its October 22, 2008, report (October Report) assessing the results of the MRTU market simulations during September 2008.[4] In the October Report, we identified five specific areas for further review and analysis:

1. **Extreme real-time market locational marginal prices (LMPs) –** Our assessment of the real-time market performance in September found that roughly 2 percent of the real-time market clearing quantities cleared at LMPs greater than $1,000/MWh. A significant share of these extreme prices have been reviewed by the CAISO and found to be due to software or technical glitches in the simulation environment that have since been corrected – though occasional glitches in the real-time simulation environment do still occur. The rest appear to be correct market optimization outcomes associated with extreme conditions – some of which are induced by particular scenarios. DMM recommended that the CAISO continue conducting in-depth analysis of the root cause of extreme LMPs to identify and correct any erroneous modeling or software issues that may be causing these prices.
2. **Price divergence between day-ahead and real-time markets –** Our analysis of September market simulation results found that prices for imports and exports on inter-ties with other control areas have tended to be significantly higher in the HASP than in the IFM. This divergence was part of a more general trend of much higher prices in the real-time market than the IFM. However, we noted that if such significant and systematic price divergences for imports and exports persisted under MRTU, it could result in market inefficiencies and potential implicit virtual bidding where market participants submit IFM bids and schedules on the inter-ties with no intent or ability to deliver (or receive) and instead intend to buy or sell back their position in the HASP. The observed price divergence between the IFM and the HASP during the September market simulations may have been simply due to the fact that market clearing load quantities in the IFM were consistently well below the simulated forecasted load, which increases demand in HASP and necessitates dispatching higher cost resources. To make sure that this persistent divergence was not due to other factors, we recommended the CAISO run structured market scenarios where a larger fraction of load clears the IFM (e.g., 95 percent) and examine the level of price divergence between the real-time market and IFM under this scenario. Additionally, to the extent there are any simulated days in October where a larger proportion of forecasted load cleared the IFM, these days should also be closely reviewed to assess the level of price convergence.
3. **Reliance on non-resource adequacy units in RUC –** Results from the September market simulations showed that the RUC process consistently awards RUC capacity to non-resource adequacy units at fairly high average RUC prices. This result is counter to expectations in that an effective resource adequacy program should generally provide sufficient capacity in RUC such that reliance on non-RA units is minimal; therefore,

[4] The October Report can be found on the CAISO website at: http://www.caiso.com/2068/2068ad206a9b0.pdf

RUC prices would generally be low if not zero.[5] If non-RA resources are routinely awarded large amounts of RUC capacity at relatively high prices in actual market operation, this could have significant market power and price distorting implications for other markets that would in our view necessitate changes to the RUC market design and/or market power mitigation rules. We noted that it is difficult to gauge whether this market outcome is likely to persist in actual market operation or is simply an artifact of the simulation, which may be resulting in less RA capacity being made available to the market than would occur in actual market operation and indicated that we would undertake additional analysis to better assess whether sufficient RA capacity is being offered to the day-ahead market. We also recommended the CAISO carefully review the RUC optimization to determine whether any of its features or input assumptions are overly restrictive or conservative, thereby causing an over-reliance on non-RA resources.[6] Additionally, we also recommended the CAISO publish RUC awards to non-RA resources on a sub-regional level (e.g., local capacity areas). Currently, only the RUC LMPs are posted on the MRTU OASIS. Posting the approximate location and quantity of non-RA RUC awards will provide better information to LSEs on the source of the RA deficiencies and potential options for addressing them.

4. **Effectiveness of local market power mitigation –** Our analysis of the September market simulations found that the LMPM procedures appear to be working as intended and are effectively mitigating local market power. However, we indicated that we would continue to review LMPM performance and that additional analysis would include:
    a. Assessing the LMPM effectiveness with nomogram constraints identified as "competitive" enforced in the competitive run of the market power mitigation procedures. Currently no competitive nomograms are enforced in the competitive run of the market power mitigation.
    b. Performing additional stress testing of the LMPM procedures by running special bidding scenarios (e.g., manually increasing the bids of resources in constrained areas and testing the LMPM effectiveness).
    c. Continuing to review and monitor default energy bids (DEBs), including DEBs developed under the consultative DEB option.
    d. Continuing to review and monitor other resource characteristics that may be submitted by participants to the CAISO Master File and/or as part of market inputs, such as:
        i. Ramp rates;
        ii. Start-up and minimum load data; and

[5] Under the MRTU market design, available capacity from RA resources is considered at a $0 price in the RUC optimization, and RA resources are not eligible to receive RUC payments.

[6] The CAISO has already undertaken some analysis of the RUC optimization and tested an alternative optimization set-up, which did not yield any appreciable difference in RUC market outcomes. It is also important to note that the CAISO typically procured additional RUC capacity beyond the forecasted load in the September market simulations to compensate for certain simulation deficiencies in the real-time market that were overstating the real-time imbalance demand. These additional RUC capacity demands, which were sometimes as high as 10 percent of forecasted demand, likely contributed to higher RUC prices.

iii. Requests for treatment as a use-limited energy resource.

5. **Skipped or failed LMPM procedures** - Importantly, our September analysis found that the LMPM procedures fail to run in the real-time market or have been skipped in as much as 5 percent of the hours.[7] Such failures are generally caused when the software fails to reach a solution in the required amount of time. We recommended the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. We committed to continue to monitor the frequency of any failures of RTM market power mitigation runs during market simulation, and recommended that these failures be formally tracked by the CAISO as a basic market performance metric. In addition, we recommended that the CAISO establish pricing provisions that may be applied in cases where the LMPM procedures are not completed in the RTM in actual market operation.

In response to the DMM recommendations, as well as similar requests from market participants, the CAISO successively conducted a structured market simulation for trade days December 9-12.[8] We used the results from these structured simulations, as well as results from other market simulation days, to further assess the five issues noted above.

The structured market simulations that were run on December 9-12 began with a realistic base-case scenario that utilized cost-based bids and reasonable assumptions about self-scheduled generation and net-imports. This base-case (Base – 0) ensured the load bids were structured such that 90-95 percent of the load forecast clears the IFM. Several variants of this base case were then run in subsequent days to test certain aspects of market performance. These and the original base-case (Base – 0) are summarized in Table 1 below.

Table 1. Summary of Structured Market Simulation Scenarios

Case	Trade Date	Description
Base - 0	December 9	Cost-based bids, 90-95% load cleared in IFM, DA forecast equals RT actual load. **Purpose:** - Examine price convergence between the IFM, HASP and RTD markets.
Base - 1	December 10	Same as Base – 0 except only 85% of the load clears the IFM. **Purpose:** - Test RUC & RT Market Performance (e.g., occurrence of extreme prices)

[7] We noted that this assessment may be over-stating the frequency of LMPM failures as the data available for this analysis may not distinguish between cases where the LMPM ran successfully but did not identify any need for bid mitigation and cases where the mitigation procedures simply failed to work. DMM has requested that the CAISO provide a more accurate metric going forward for tracking and discerning actual mitigation failures from cases where no mitigation was required.

[8] In November, the CAISO initially tried to perform structured base-case analysis separate from the market simulations. However, this approach proved to be difficult to complete for the HASP and Real Time Market. Consequently, an alternative approach was adopted in December.

		- Examine price divergence between IFM, HASP, RTD
Base - 2	December 11	Same as Base – 0 except submit extreme generator bids in load pockets **Purpose:** - Test LMPM Effectiveness
Base - 3	December 12	Same as Base – 0 except real-time load forecast 5% higher in all IOU territories (PG&E, SCE & SDG&E) **Purpose:** - Test RT Market Performance (e.g., occurrence of extreme prices) - Test LMPM Effectiveness - Examine price divergence between IFM, HASP, RTD

As noted earlier, while the structured market simulations in December were of better quality in terms of the submitted bids and schedules and constructed scenarios, they were far from perfect and ultimately suffer from the unavoidable fact that until real dollars are at stake, market participants are not going to exert the level of thought and effort and reaction to observed prices that they would in actual market operation. Consequently, we remain cautious in inferring too much from these simulations.

III. General Market Performance

Residual Unit Commitment (RUC)

This section reviews the performance of the Residual Unit Commitment (RUC) market in the structured simulations with particular focus on the availability of Resource Adequacy (RA) capacity in the day-ahead market. As noted in the overview, in our October Report, we raised a concern about the level and frequency of RUC awards to non-RA resources and pointed out that if this were to occur in actual market operation, it could have significant market power and price distorting implications for other markets that would in our view necessitate a change to the RUC design. This concern was based on the market simulation results for September. More recent market simulation results, including the structured market simulations discussed here, show much smaller amounts of RUC capacity being awarded to non-RA capacity and in much fewer hours. Moreover, the RUC prices paid for this capacity are generally moderate. Consequently, we are less concerned about this issue and do not believe that any changes in the RUC design are necessary prior to MRTU go-live.

We will be closely monitoring the performance of the RUC market after go-live. We also strongly encourage the Load Serving Entities to mitigate reliance on non-RA resources in RUC through proactively managing their RA portfolio to ensure sufficient RA capacity is being made available to the CAISO Day Ahead Market.

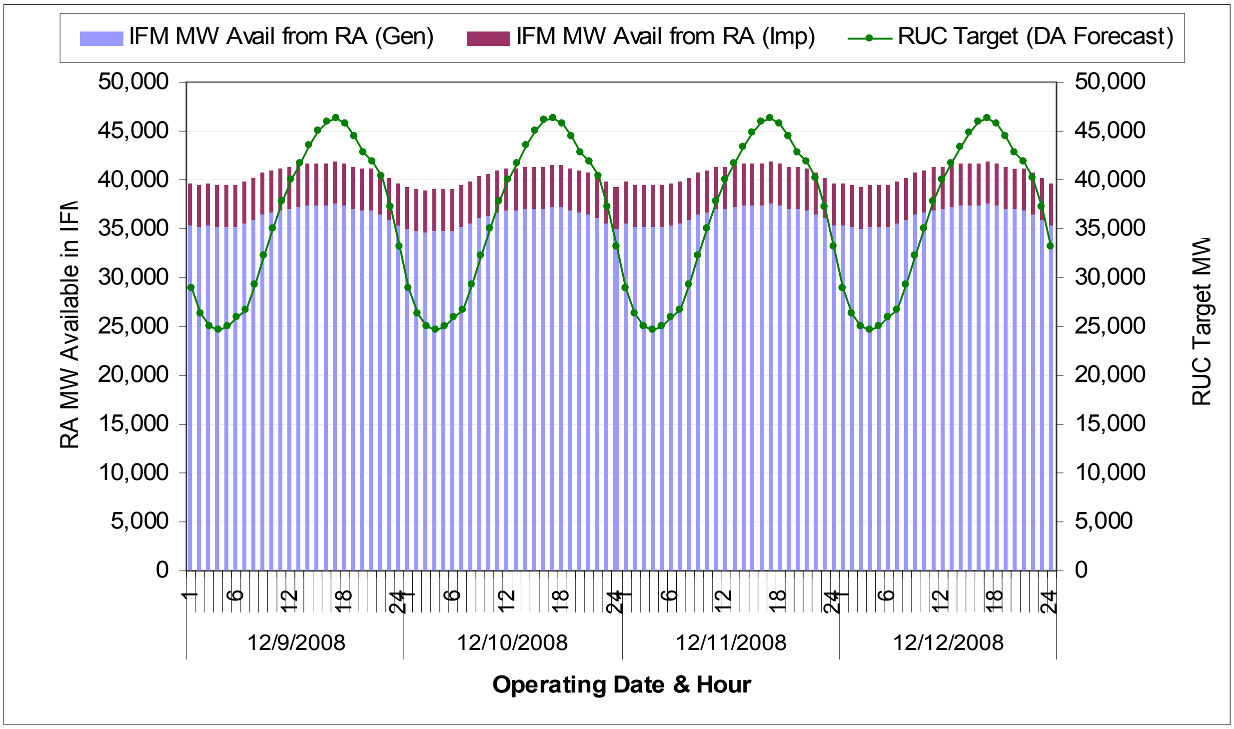
Finally, we also recommend that the CAISO consider alternatives to the current RUC design for implementation after MRTU go-live. Importantly, we believe the current RUC design may be incompatible with nodal convergence bidding and could create gaming opportunities where suppliers use virtual bidding strategies in the IFM to cause reliance on non-RA capacity in RUC. As the CAISO works towards finalizing its convergence bidding market design it should consider the implications and compatibility of that design with RUC – among other things.

A detailed review of the RUC results for the structured market simulations is provided below.

Resource Adequacy and RUC

Figure 1 compares the total RA capacity (generation and imports) made available to the IFM to the day-ahead load forecast used in RUC. The peak load forecast in the structured simulation was approximately 46,000 MW, and, as can be seen in Figure 1, the identified RA capacity available to the IFM (import and generation resources) was considerably less than that – by approximately 5,000 MW across the peak hour. Having insufficient identified RA capacity to meet forecasted load does not necessarily mean that non-RA capacity will be procured in RUC. To the extent energy from non-RA capacity from internal generation and imports clears against load in the IFM, there could be sufficient unloaded capacity from RA resources to meet any residual capacity requirements in RUC. Nonetheless, the shortage does increase the likelihood that non-RA capacity will be needed in RUC.

Figure 1. Comparison of RA Capacity to DA Load Forecast (December 9-12)



A more detailed examination of the RA capacity available to the IFM is provided in Table 2. Specifically, Table 2 provides a breakdown of the various types of RA capacity, showing for each type of capacity:

- The amounts identified in the July 2008 RA showings to the CAISO, which was the assumed RA month for the structured simulations (column 2).
- The amounts identified in the CAISO MRTU Master File used for the structured simulations (column 3).
- The amounts ultimately offered to the IFM in the structured simulation for December 10, Hour 16 (left three columns).

In comparing the RA showings to what was registered in the CAISO Master File, we see that essentially all of the resource-specific RA capacity identified in the July 2008 RA showings (generation and imports) was identified in the CAISO Master File used for the structured simulation. However, a significant share of the July 2008 RA showing (approximately 9,400 MW or 18 percent) is comprised of non-specific resources (e.g., liquidated damages (LD) contracts) for which the CAISO market systems have no ability to identify. The total amount of energy bids submitted to the IFM from identified RA generation capacity was 37,030 MW – roughly 94 percent of the total RA generation capacity identified in the RA showing. There were 4,251 MW of energy bids were provided from RA import resources, representing approximately 86 percent of the 4,900 MW of imports identified in the RA showing.

Table 2. Summary of RA Availability (Dec 10, 2008, Hour 16)

Type of Resource	July 2008 RA Showings (MW)	RA Capacity in Structured Simulation Master File (MW)	Bid Quantity Included in IFM (Dec 10, 2008 HE 16)		
			MW	Percentage of Struc. Sim MF RA Cap.	Percentage of July 2008 RA Showing
Gas Generation - Must Offer		22,624	22,059	98%	
Gas Generation - Non-Must Offer		1,587	1,247	79%	
Hydro Generation - Non-Must Offer		6,255	5,325	85%	
Other Generation - Must Offer		760	758	100%	
Other Generation - Non-Must Offer		8,217	7,641	93%	
Total Gen	38,682	39,442	37,030	94%	96%
Imports	4,916	4,921	4,251	86%	86%
Other RA Resources - (DWR contracts, LD contracts, etc)	9,388	Non-Resource Specific	?	?	?
Total	52,986	44,363	41,281	93%	78%

The amount of incremental capacity that is procured in RUC is largely dependent on how much load clears the IFM relative to the load forecast. Figure 2 shows the hourly percentage of day-ahead forecasted load that cleared the IFM in each hour of the structured simulation (Dec 9-12). With the exception of December 10, the IFM generally cleared approximately 95 percent of forecasted load during the peak hours. The market simulation for December 10 was structured to only clear 85 percent of the load-forecast during the peak hours.

Figure 2. IFM Load Clearing Quantities (December 9-12)

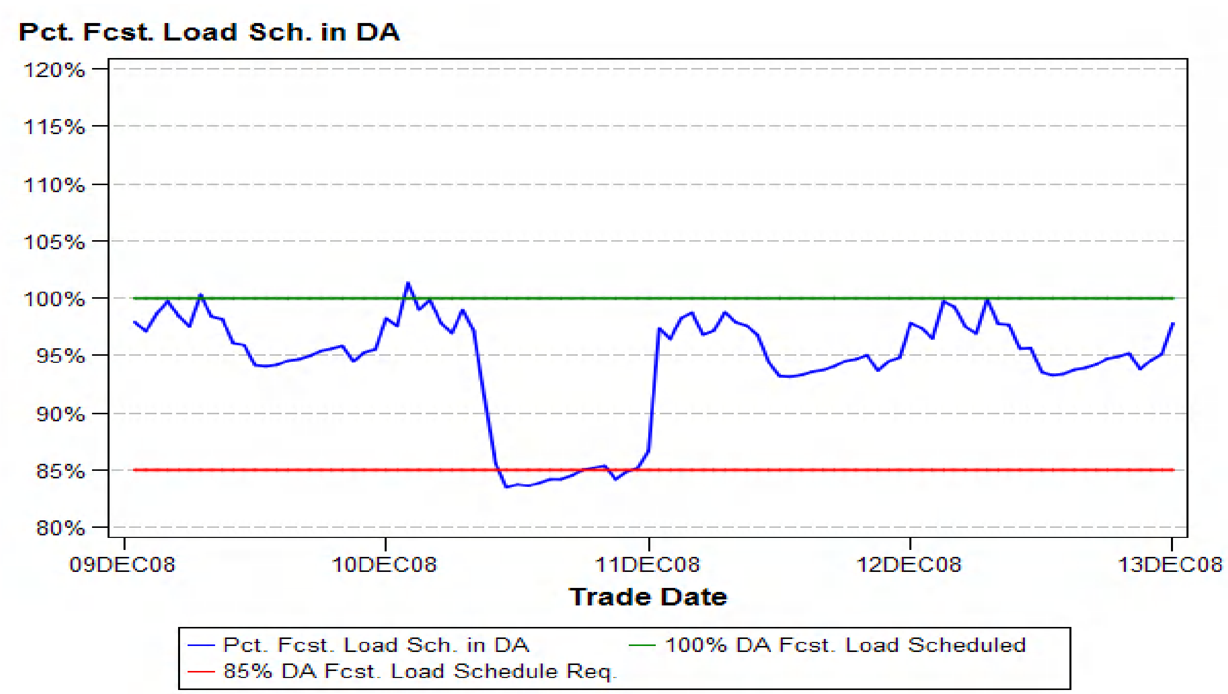


Figure 3 compares the RA capacity available to the IFM (green line) to the amount of RA capacity that was taken for energy or ancillary services in the IFM (blue column) and the amount of available RA capacity in RUC (red column). Importantly, the figure demonstrates that not all of the RA capacity that was made available to the IFM was made available to RUC. Approximately 2,500-3,000 MW of RA capacity available to the IFM was not made available to RUC. This shortfall appears to be primarily attributable to bids that are submitted for hydro and use-limited resources to the IFM but not submitted to RUC.

Figure 3. Comparison of Available RA Capacity in IFM and RUC (Dec 9-12)

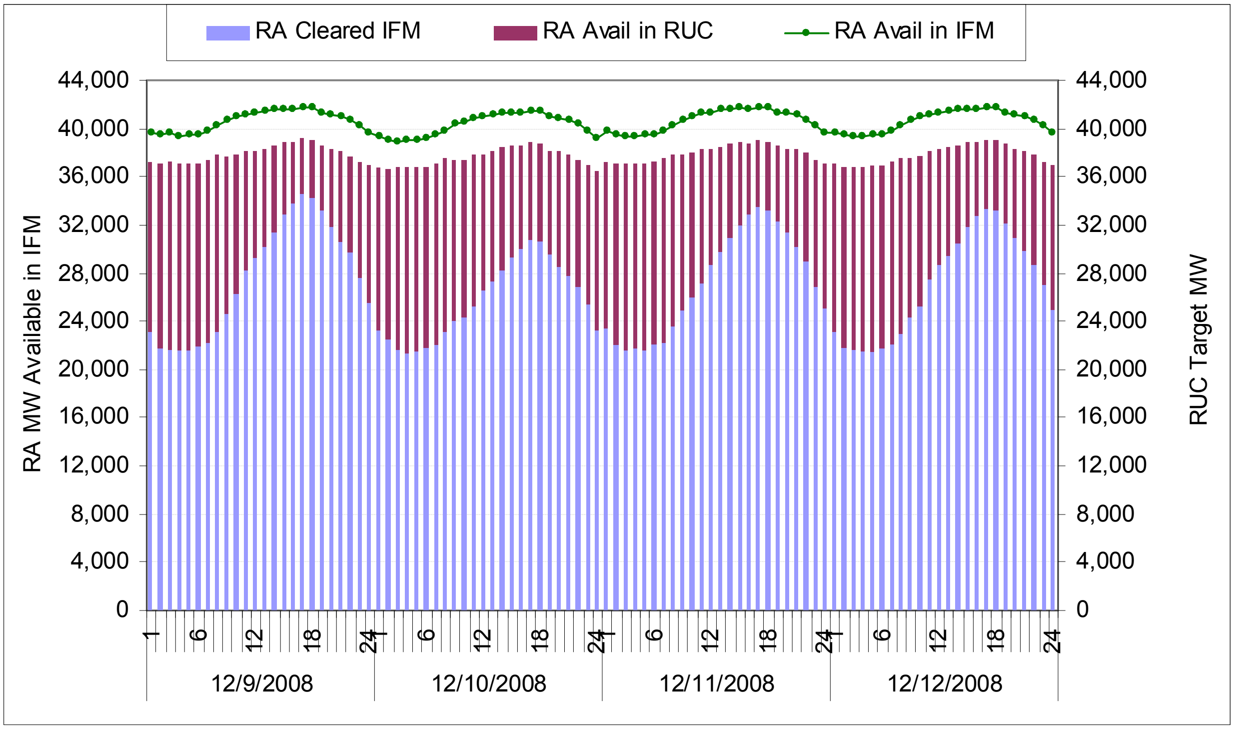
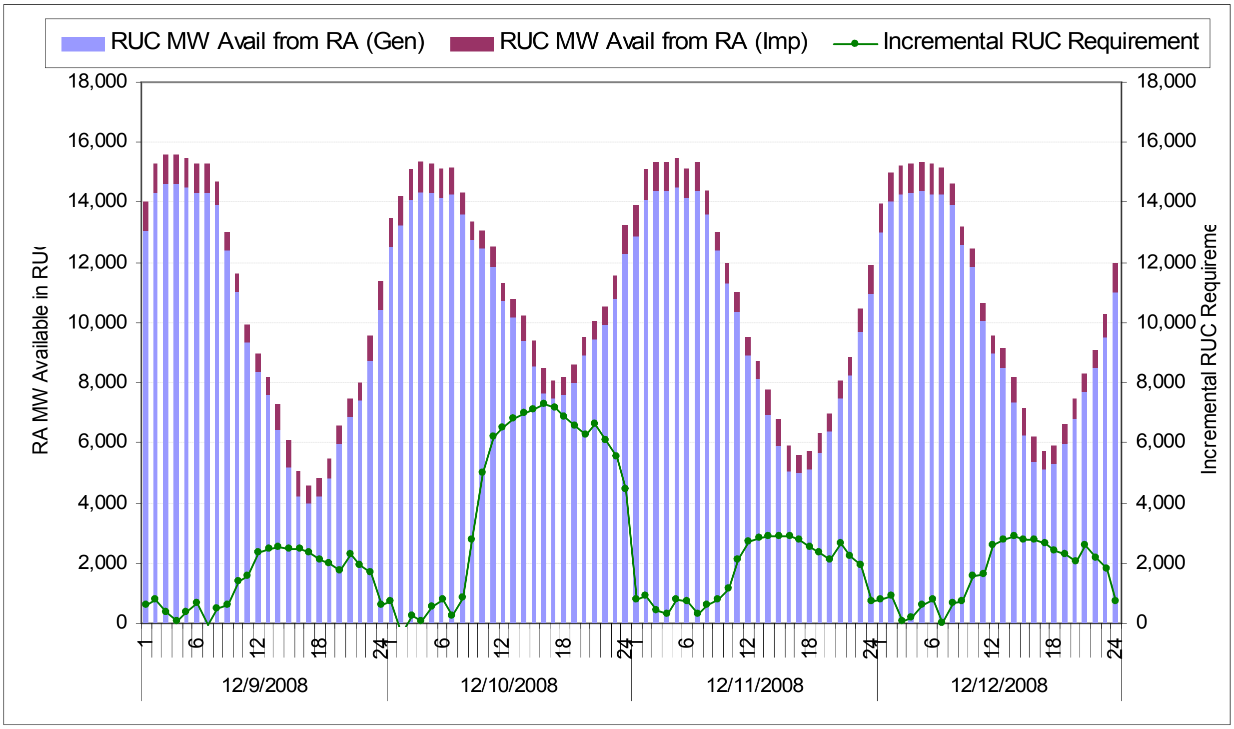


Figure 4 compares the incremental RUC system capacity requirement (i.e., load forecast less the amount of energy cleared in the IFM (generation and net-imports)) and the RUC capacity available from RA resources (i.e., RA capacity not taken for energy or ancillary services in the IFM that was made available to RUC). This comparison suggests there was sufficient RA capacity in RUC to meet the incremental system RUC requirements. However, since some of this capacity may be transmission or ramp constrained, reliance on non-RA capacity in RUC occurred in this hour and several others during the structured simulation. Moreover, some of this RA capacity may be associated with generating units that were not committed in the IFM and consequently the RUC optimization may find it more optimal to award RUC to already committed non-RA capacity than to incur the cost of committing an RA unit. Nevertheless, the CAISO is planning to conduct a more detailed review of the resources available in RUC and RUC commitments.

Figure 4. Available RA Capacity and Incremental RUC Requirements (Dec 9-12)



RUC Results

Figure 5 shows the hourly quantities of RUC awards to non-RA capacity and the average and maximum RUC LMPs paid for that capacity. The results show that RUC awards to non-RA capacity were relatively minor compared to the incremental RUC requirements shown in Figure 4. Average and maximum RUC LMPs paid for non-RA capacity were at or below $25/MW in most hours with the exception of four hours that experienced relatively high RUC LMPs in excess of $100/MW, and, in some cases, in excess of $200/MW. These prices and RUC awards are examined more closely below.

Figure 5. RUC Procurement from Non-RA Capacity (December 9-12)

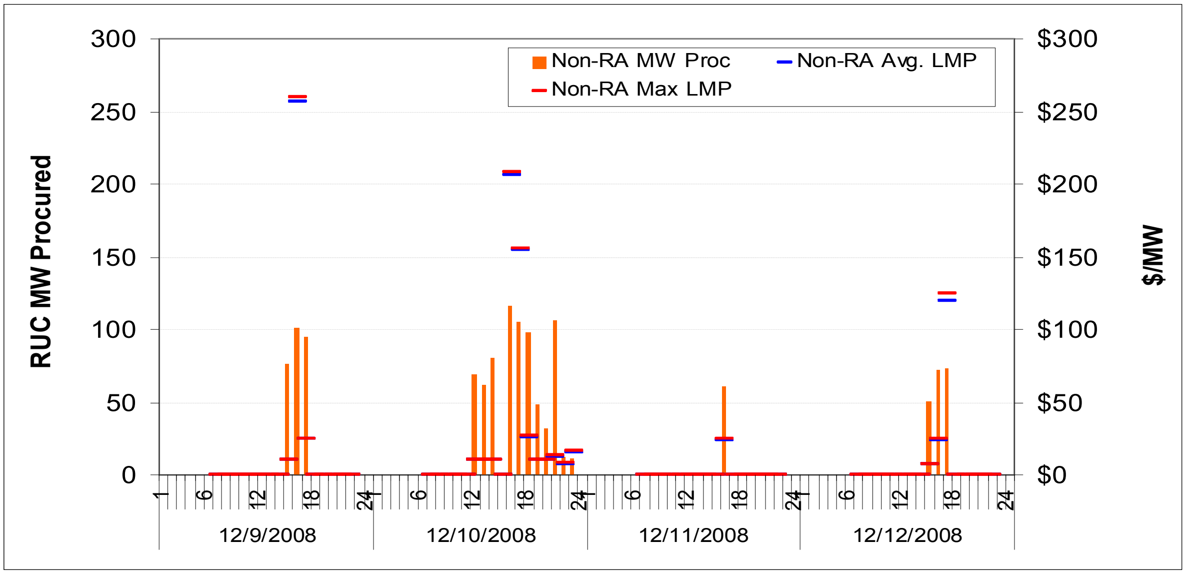


Table 3 provides additional details on the three hours of the structured simulation where RUC LMPs paid for non-RA capacity were in excess of $150/MW. Specifically, Table 3 shows the range of RUC LMPs paid to non-RA capacity from various generating units, which in total amounted to approximately 100 MW of capacity procurement in each hour. Table 3 also shows the energy component of the RUC LMPs and the ranges of the congestion and marginal loss LMP components. The very high system energy component of RUC LMPs observed in these hours strongly suggests that the RUC capacity procured from these resources was for system needs as opposed to local constraints.

Table 3. RUC LMP Decomposition at P-Nodes with Non-RA RUC Awards

Date	Hour	RUC LMP Range ($/MWh)	RUC LMP Decomposition ($/MWh)		
			Energy	Congestion Range	Losses Range
12/9/08	16	247 – 260	259	-2.70 - 0	-12.11 - .26
12/10/08	16	198 – 208	208	-2.70 - 0	-9.72 - .64
12/10/08	17	148 – 156	155	0	-7.28 - .70

Real Time Market Performance

In our October Report, we noted that roughly 2 percent of the real-time LMPs observed in the September market simulations cleared at LMPs greater than $1,000/MWh. We further noted that a significant share of these extreme prices were due to occasional glitches in the market simulation environment and to modeling or software glitches that have since been corrected. Nonetheless, we recommended that the CAISO continue to closely review the root cause of extreme LMPs in the on-going market simulations to determine whether there are any other modeling or software deficiencies causing extreme prices.

We also raised a concern in the October Report about the observed levels of price divergence between the day-ahead and real-time markets (HASP, RTD), and noted that if such extreme levels of price divergence occurred in actual market operation, it would create incentives for implicit virtual bidding where market participants submit day-ahead bids and schedules at the inter-ties with no ability or expectation to physically deliver (or receive) energy. Instead, their intent is to sell or buy back their position in HASP. While we noted that the observed pattern of real-time prices being generally much higher than day-ahead prices was likely due to the fact that load was significantly under-scheduled in the IFM during the September market simulations, we recommended the CAISO conduct structured market simulations where a larger portion of load clears the IFM (e.g., 95 percent) to see if there is an improvement in price convergence.

The structured market simulations performed in December were designed to assess both of these issues. However, while the structured market simulations in December were of better quality in terms of the submitted bids and schedules and constructed scenarios, they were far from perfect, and ultimately suffer from the unavoidable fact that until real dollars are at stake, market participants are not going to exert the level of thought and effort and reaction to observed prices that they would in actual market operation. Consequently, we remain cautious in inferring too much from these simulations. With this caveat, our general assessment of the December structured market simulations is that they produced – in most hours – more realistic and explainable real-time market outcomes.

- With the exception of December 12, extreme real-time market prices were less frequent than observed in the September simulations but still need further detailed review to understand their root causes. The CAISO is currently working with DMM and market participants in undertaking a deeper analysis of a subset of extreme prices observed in the structured market simulation.

- Extreme real-time market prices observed on December 12 appear to be due to a combination of reduced supply bids and increased demand, the combination of which resulted in severe system shortages. We do not consider the structured scenario for this day to be very realistic and the extreme results observed on that day were reflective of the limitations of the simulation as opposed to what we would expect in actual market operation. Specifically, if the CAISO experienced such a significant increase in real-time energy demand in actual operation on a peak summer day, we believe that there would be a significant market response of increased supply, particularly at the inter-ties, which would mitigate extreme prices, whereas the structured simulation had essentially no supply response. Moreover, such an extreme event would likely trigger demand response programs, which did not happen under the structured simulation. The extreme prices observed in the simulation for this day appear to reflect various transmission constraint violations. However, we recommend that the CAISO closely examine a sample of these extreme prices to confirm their root cause.

- Day-ahead and real-time LAP prices generally showed better price convergence than observed in the September simulations, particularly during shoulder hours of the day. Real-time prices during the peak hours were still fairly volatile and higher than day-ahead prices but we suspect this has more to do with deficiencies in the simulation environment than some systematic bias in the market software.
- Prices at the inter-ties also generally showed better convergence than observed during the September simulations – though not at a level that we would expect under actual market operation. As expected, prices at the inter-ties generally diverged more under the load under-scheduling scenario that was executed on December 10.

A more detailed review and assessment of real-time market performance is provided below.

December 9, 2008

Figure 6 - Figure 8 below show the Day Ahead, HASP, and Real Time prices for the PG&E, SCE, and SDG&E Load Aggregation Points (LAPs), respectively, for December 9, 2008. As evident in these three figures, the LAP prices for all three locations followed almost identical patterns. The anomalous pricing patterns observed in the Real Time Market in the morning hours (HE 1-11) were due to data problems with the simulated resource telemetry and therefore are not valid. The telemetry issue was corrected in HE 12 and the simulation of the Real Time Market performed well for the remainder of the day. Some price spikes were observed in the Real Time Market for the peak hours of the day (HE 14-18). These 5-minute interval LAP price spikes were in the range of $400-$450/MWh for PG&E and SCE LAPs but higher for the SDG&E LAP – ranging between $400/MWh to just over $600/MWh. Also of note is that the spikes generally occurred during the later intervals of each hour, which suggests that they were caused by a depletion of ramping capability. These high LAP prices, which are discussed in greater detail below, were limited to just a few 5-minute intervals. For the rest of the day (ignoring the morning hours), the Day Ahead, HASP, and Real Time Market LAP prices showed reasonable price convergence.

Figure 6. PG&E LAP Prices (DA, HASP, RTD) - December 9, 2008

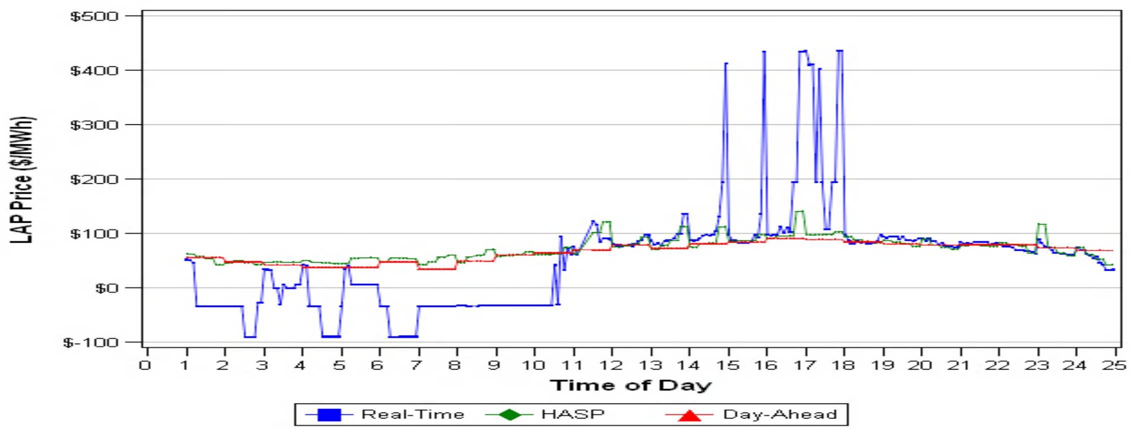


Figure 7. SCE LAP Prices (DA, HASP, RTD) - December 9, 2008

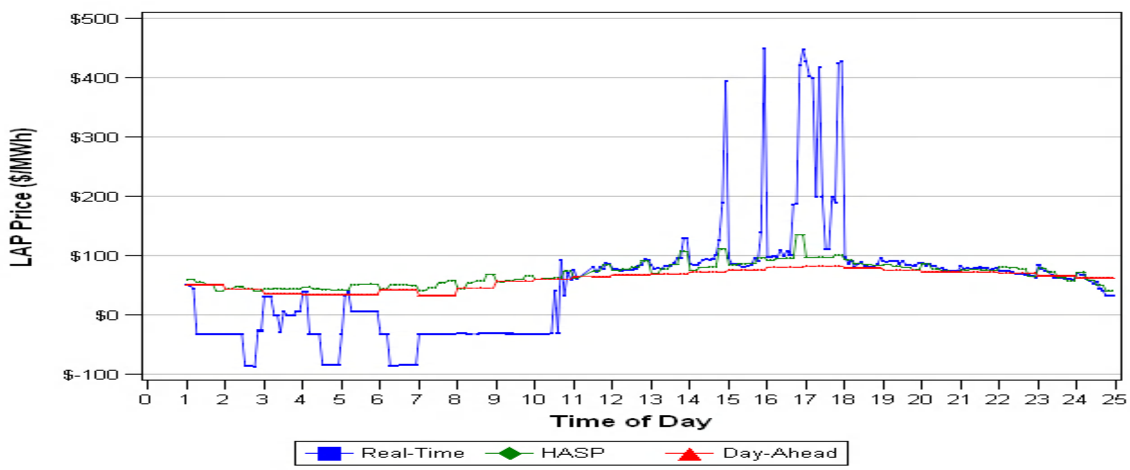


Figure 8. SDG&E LAP Prices (DA, HASP, RTD) - December 9, 2008

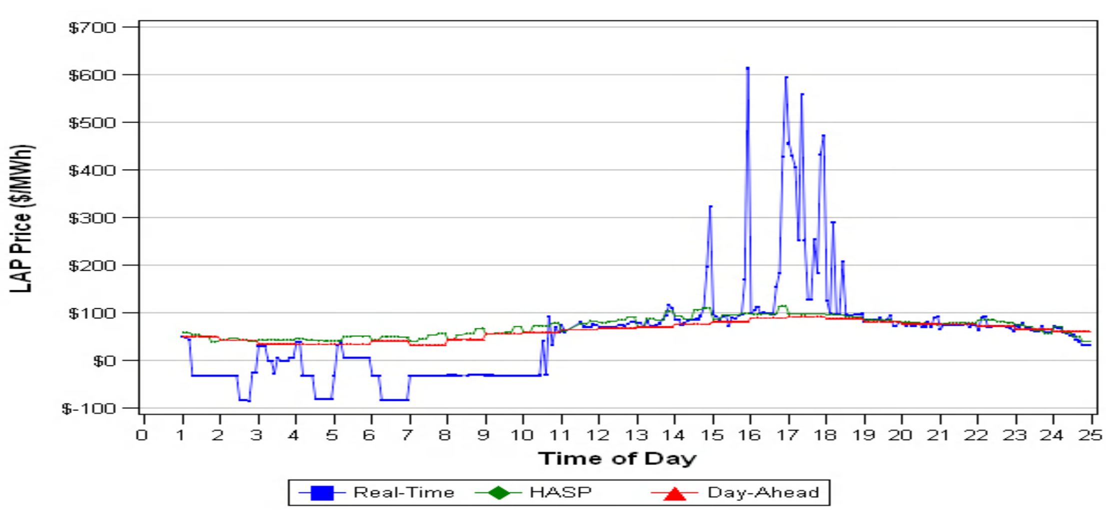


Figure 9 compares the HASP LAP prices for PG&E, SCE, and SDG&E. The HASP prices for all three LAPs tracked similarly throughout the day, particularly the PG&E and SCE LAP prices, while the SDG&E LAP prices showed some separation during the latter half of the day.

Figure 9. Comparison of HASP LAP Prices (December 9, 2008)

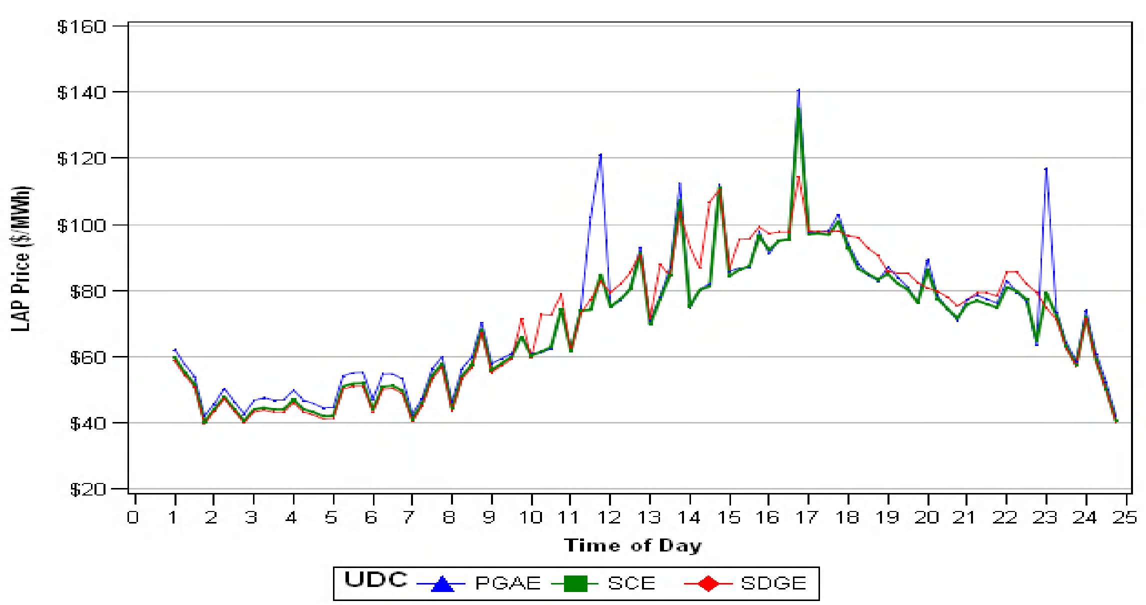
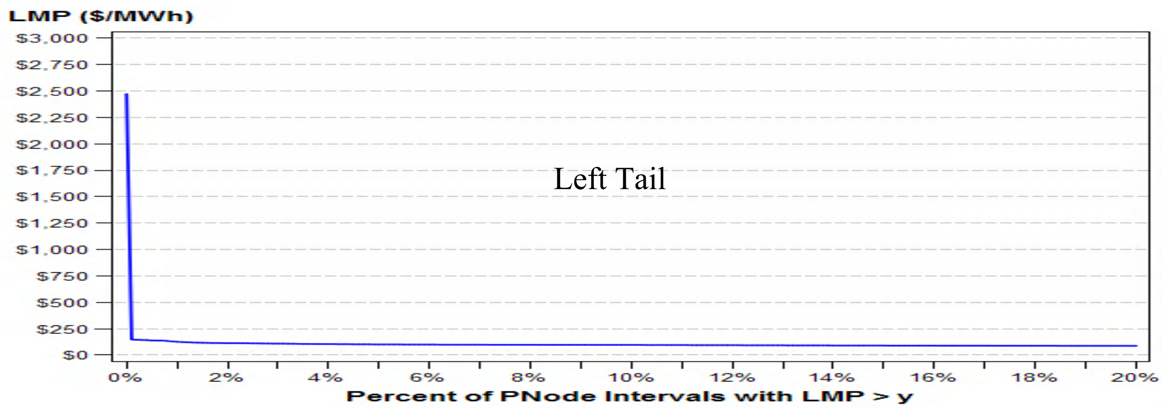


Figure 10 shows a price duration curve for all the HASP LMPs on December 9. To focus on the frequency of extreme prices, Figure 10 shows just the left and right tails of the price duration curve. As evident in the left tail of the LMP price duration curve, the frequency of extreme positive LMPs (i.e., LMPs greater than $500/MWh) was extremely limited – comprising less than a tenth of a percent of the total HASP LMPs produced for that day. The right tail of the LMP price duration curve (showing the lowest HASP LMPs) indicates that roughly two percent of LMPs were below zero and were in the range -$27/MWh to -$42/MWh.

Figure 10. HASP LMP Duration Curve (December 9, 2008)



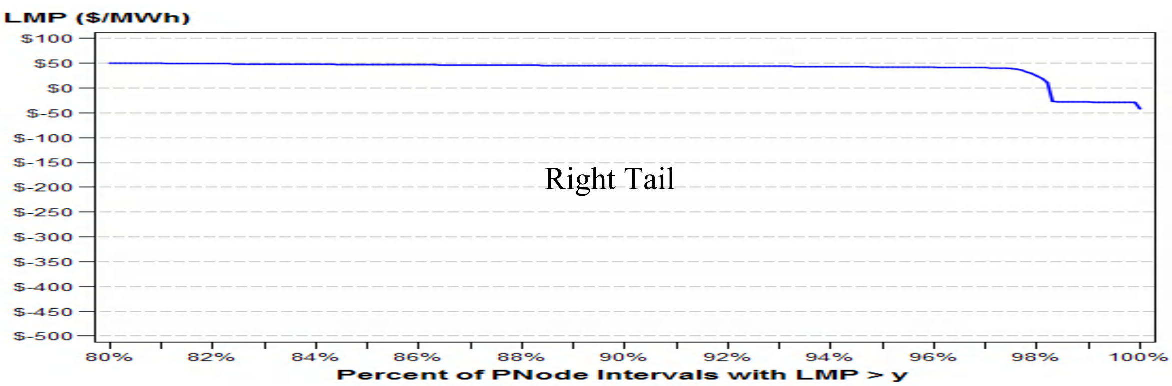


Figure 11 shows when extreme HASP LMPs occurred throughout the operating day. Negative HASP LMPs (between -$30 and -$100/MWh) occurred predominately in three specific intervals (HE 2 - Interval 2, HE 5 – Interval 2, HE 7 – Interval 2). The occurrence of negative prices in interval 2 during the morning hours could be related to inter-hour energy ramping. Since the inter-hour energy ramp is completed in interval 1, it could create a surplus of energy in interval 2 that would be mitigated through downward dispatch. Extreme positive HASP LMPs were limited predominately to three specific intervals (HE 11 - Intervals 3 & 4, HE 23 – Interval 1) and were limited to a small subset of nodes.

Figure 11. HASP LMP Frequencies by Interval (December 9, 2008)

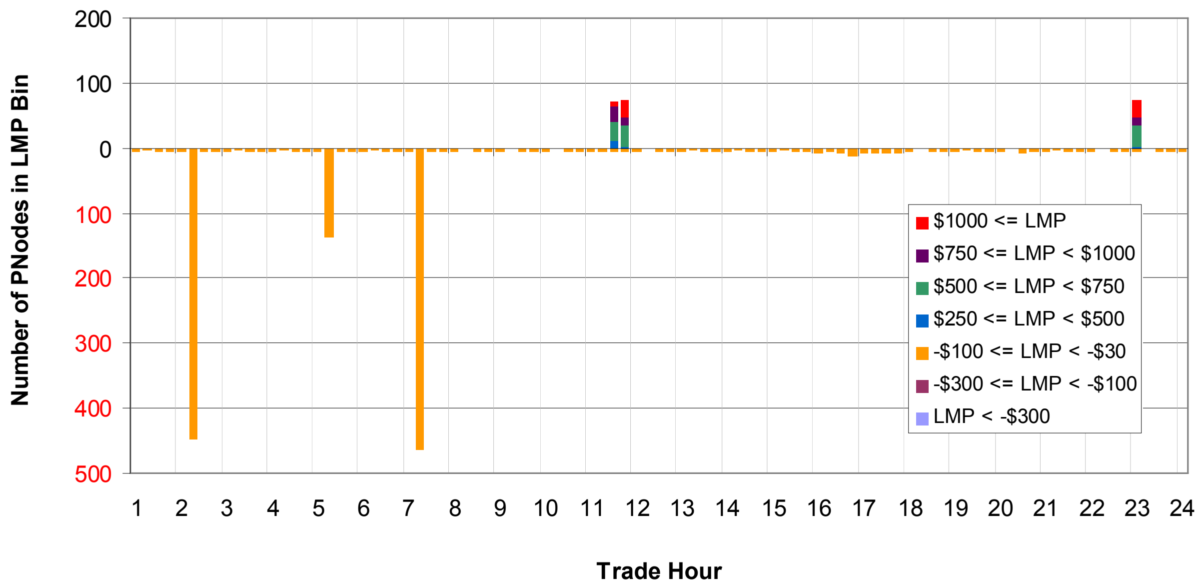
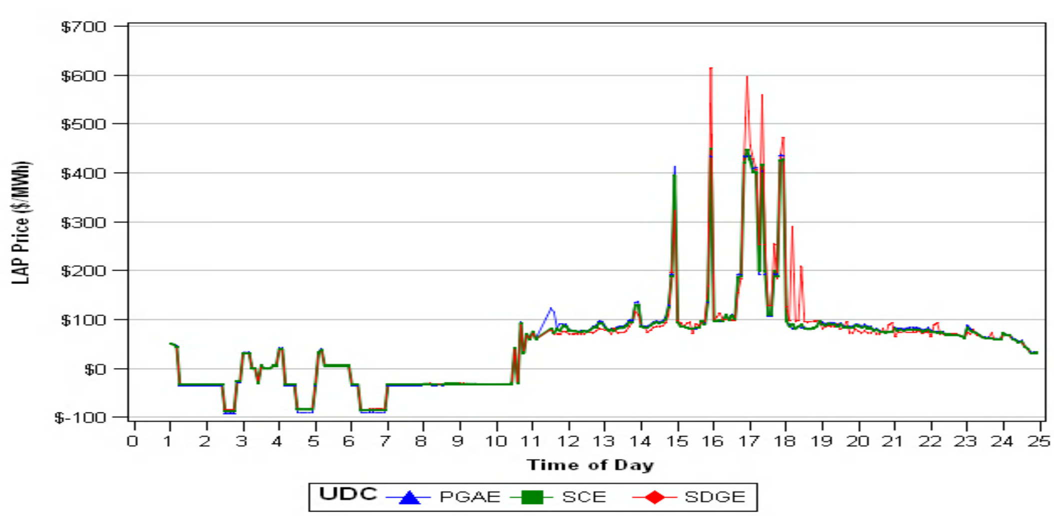


Figure 12 shows a comparison of Real Time Dispatch (RTD) prices for the PG&E, SCE, and SDG&E LAPs. Similar to the HASP, all three LAP prices tracked very closely throughout the day but the SDG&E LAP price exhibited greater separation from the other two LAP prices. SDG&E LAP prices were particularly higher in a number of intervals during the peak hours of the day. All three LAP prices showed volatility across the peak hours with a number of price spikes at or above $400/MWh.

Figure 12. Comparison of RTD LAP Prices (December 9, 2008)



Analysis of congestion and LAP prices indicates that RTD LAP prices for PG&E and SCE, including high prices, were predominately due to system energy needs, whereas the San Diego LAP price had a significant congestion component that generally pushed it above the PG&E and SCE LAP prices. Specifically, only two transmission constraints were binding during the intervals when at least one RTD LAP price exceeded \$200/MWh: 1) the Miguel flowgate (located in SDG&E), and (2) the Morgan Hill to Llagas flowgate (located in PG&E). The shadow values of these constraints are shown in Table 4. The difference between SDG&E and SCE LAP prices appears to be driven by congestion on the Miguel flowgate, as evident in Table 4 and Figure 13. The Morgan Hill to Llagas congestion, which was binding under the Metcalf to Morgan Hill contingency, did not appear to have a big impact on the PG&E LAP price – though high shadow prices for this constraint were highly correlated with high LAP prices for both PG&E and SCE (Figure 14).

Table 4. RTD Binding Constraints when LAP Price > $200/MWh (Dec 9)

Hour	Interval	Constraint Shadow Prices* ($/MW) Miguel	Morgan Hill - Llagas	LAP Prices ($/MWh) PG&E	SCE	SDG&E
14	1	41	0	88	85	86
	2	40	0	87	85	85
	3	0	0	87	84	75
	4	6	0	91	88	79
	5	11	0	96	93	85
	6	12	0	98	95	86
	7	17	0	96	93	86
	8	13	0	98	95	87
	9	20	0	104	101	94
	10	7	35	131	126	110
	11	149	95	194	189	197
	12	0	302	413	395	323
15	1	54	42	98	96	98
	2	69	32	87	85	93
	3	22	32	87	86	87
	4	34	28	83	84	92
	5	89	27	82	81	95
	6	0	29	83	81	72
	7	33	27	82	83	91
	8	26	29	84	85	88
	9	27	42	98	97	95
	10	68	37	92	91	97
	11	128	78	136	139	169
	12	682	360	435	449	614
16	1	21	122	97	98	98
	2	35	121	96	98	106
	3	60	122	97	99	113
	4	24	122	97	97	99
	5	26	136	112	109	100
	6	55	125	101	99	100
	7	25	134	111	108	99
	8	41	127	103	101	98
	9	0	212	194	187	155
	10	107	213	194	188	183
	11	347	441	435	421	429
	12	624	441	435	448	596
17	1	392	441	436	427	456
	2	366	417	410	402	429
	3	325	419	412	400	407
	4	229	213	194	200	254
	5	597	411	403	417	559
	6	229	213	194	200	254
	7	79	132	108	111	129
	8	79	132	108	111	129
	9	229	212	194	200	254
	10	108	213	194	189	184
	11	350	442	437	425	432
	12	501	442	437	427	473
18	1	161	43	98	98	126
	2	88	33	88	87	98
	3	845	26	81	91	290
	4	102	27	82	81	97
	5	86	32	87	86	98
	6	509	29	84	90	209
	7	113	30	85	83	96
	8	95	27	82	81	96
	9	95	27	82	81	96
	10	96	28	83	83	97
	11	89	31	86	85	97
	12	59	42	98	96	98

* Aqua color indicates constraint violations

Figure 13. RTD LAP Prices & Miguel Congestion (Dec 9, Hours 14-18)

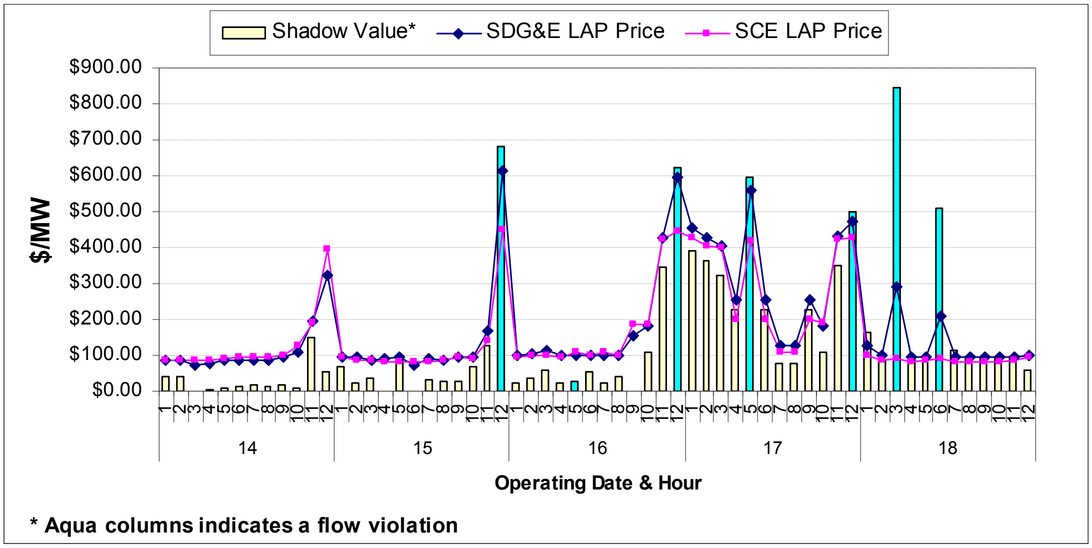


Figure 14. RTD LAP Prices & Morgan to Llagas Congestion (Dec 9, 2008, Hours 14-18)

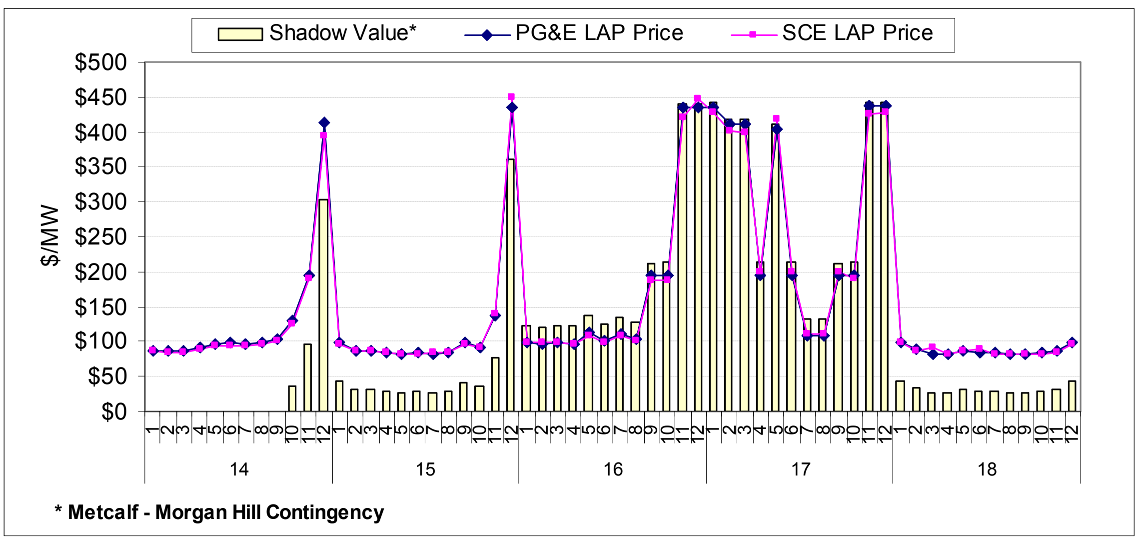


Figure 15 shows the right and left tails of the RTD LMP duration curve but excludes LMPs for Hours 1-11 due to the telemetry issues previously noted. As evident in the left tail of Figure 15, RTD LMPs in excess of $500 were extremely limited on December 9, comprising less than .25 percent of total RTD LMPs. Similarly, there were very few negative LMPs.

Figure 15. RTD LMP Duration Curve (December 9, 2008 HE 12-24)

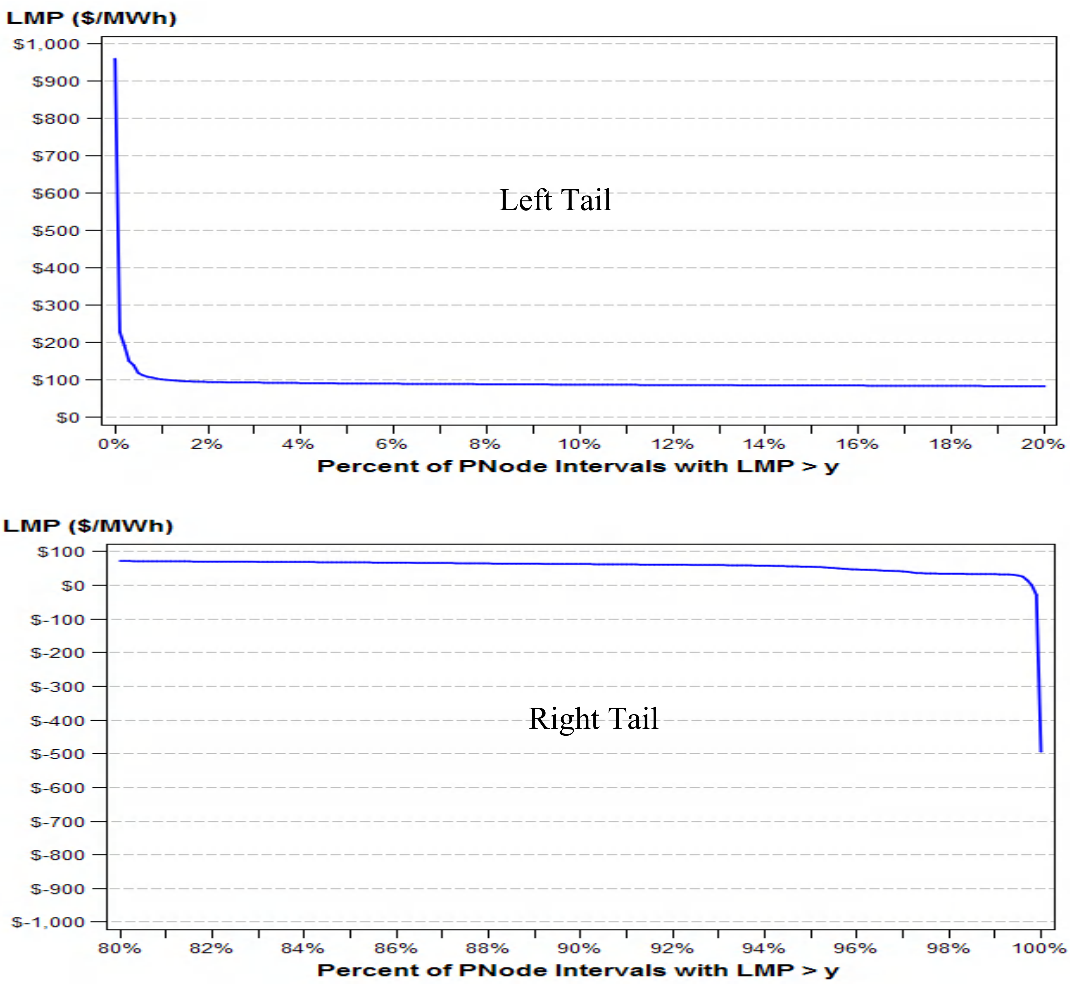


Figure 16 shows the number of P-Nodes having RTD LMPs within certain price ranges for each interval of the operating day. When relatively high LMPs occurred (in excess of $250/MWh), they tended to be system-wide – as evident by the number of P-Nodes shown in Figure 16. However, LMPs in excess of the $500 bid cap were limited to a subset of nodes. High LMPs also tended to occur in the later intervals of each hour. This trend may be due to a limitation of ramping energy in the later intervals of the hour or may also be related to two other issues, one of which relates to a problem in the way the real-time market simulation treats the regulation range of generating units and the second of which relates to a known software variance that is being corrected concerning modeling the inter-hour ramping of energy schedules. These two issues are described in greater detail below:

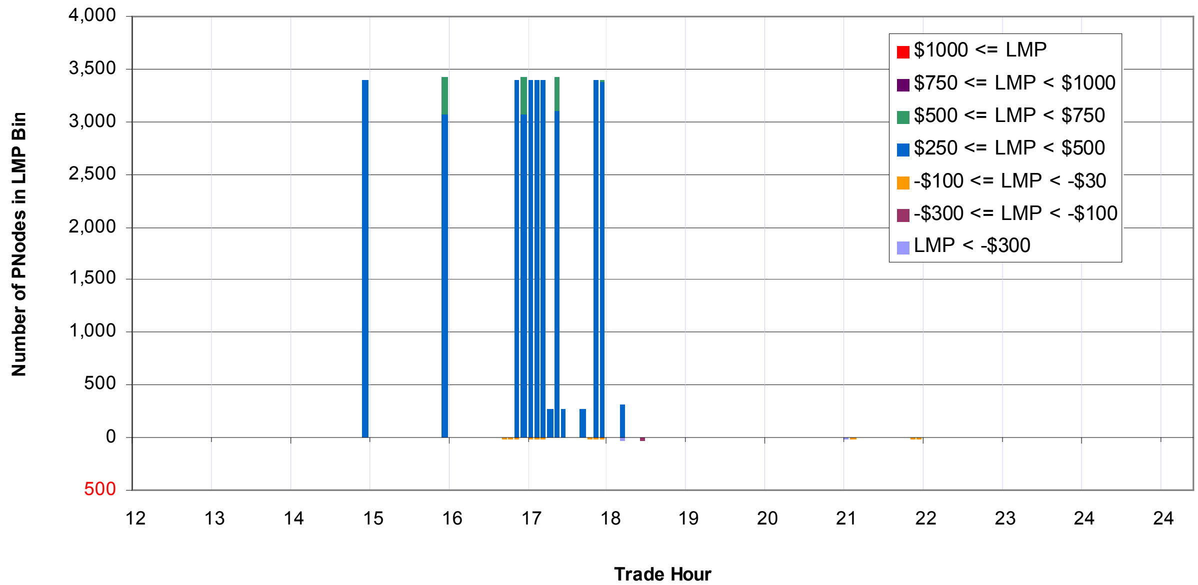
- **Regulation Range Modeling.** The RTM software is designed to constrain energy dispatches issued to units providing regulation so that these units do not operate outside of their *regulation range* (or minimum and maximum operating levels when providing regulation). For the current operating hour, the regulation range used is based on telemetered data provided by the plant. For the next trading hour, the regulation range used by the software is based on the regulation ranges established in the Master File. During market simulation, however, the current telemetered regulation range for the current hour must be simulated. This simulated regulation range is established based on the minimum and maximum operating levels (Pmin and Pmax), rather than the actual regulation range. As a result, units on regulation may be dispatched above their regulation range to provide real-time energy during the initial portion of an operating hour, and may then be constrained back into their regulation range in the last few intervals of the hour. This could contribute to or exacerbate price spikes during the last few intervals of each hour by reducing the energy available from these units during these intervals (as well as requiring that other units be dispatched to compensate for adjustments being made to enforce regulation range constraints on units providing regulation). Since this trend is caused by the simulator used to generate inputs to the RTM during market simulation, it should not occur after MRTU implementation, when the RTM software will be run using actual telemetered data from each generating unit.[9]

- **Inter-Hour Ramping Software Variance.** The RTM software design specifies that resources will be ramped up or down from their hourly self-scheduled operating levels from one hour to the next over a 20 minute period, starting 10 minutes prior to the end of the prior operating hour (*t*-10) and ending 10 minutes after the start of the next operating hour (*t*+10). However, in the RTM software currently being used in Market Simulation, resources are ramped up or down to their scheduled operating level for the next operating hour only during the first 10 minutes of that operating hour (*t* to *t*+10).[10] This software variance has been resolved and is currently being tested. It will be promoted to the production system prior to MRTU implementation. However, during market simulation, this could have the effect of contributing to or exacerbating price spikes during the last few intervals of each hour by reducing the ramping energy available during these intervals.

[9] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, January 13, 2009 slide 7,(http://www.caiso.com/2335/233585cc3b090.pdf)

[10] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, January 13, 2009 slide 6, (http://www.caiso.com/2335/233585cc3b090.pdf)

Figure 16. RTD LMP Frequencies by Interval (December 9, 2008)



December 10, 2008

As noted in the introduction, the December 10 simulation varies from December 9 in that Day Ahead LAP demand bids were modified so that approximately 80-85 percent of the Day Ahead load forecast clears the IFM. Figure 17 - Figure 19 below show the Day Ahead, HASP, and Real Time prices for the PG&E, SCE, and SDG&E Load Aggregation Points (LAPs), respectively, for December 10, 2008. Similar to December 9, the LAP prices for all three locations followed almost identical patterns. The anomalous pricing patterns observed in the Real Time Market in the morning hours (HE 2-3) were due to data problems with the simulated resource telemetry and therefore are not valid pricing points. The price spikes observed in the HASP and Real Time Market for the peak hours of the day (HE 14-18) were more sustained compared to December 9. LAP prices in HASP and RTD across the super peak hours were generally in the range of $400-$600/MWh with HASP LAP prices tending to be more in the high end of this range. Similar to December 9, LAP prices for PG&E and SCE were almost identical with SDG&E exhibiting greater separation. As expected, with less load clearing the IFM, LAP prices in HASP and RTD were generally higher than day-ahead prices. This is most noticeable in hours 10-15. Across the peak hours, HASP and RTD prices were also reasonably well converged.

Figure 17. PG&E LAP Prices (DA, HASP, RTD) - December 10, 2008

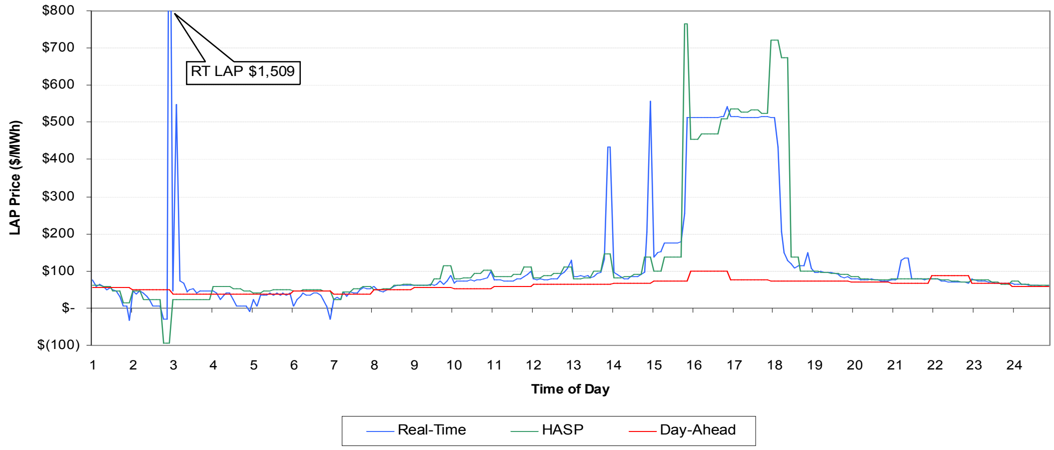


Figure 18. SCE LAP Prices (DA, HASP, RTD) - December 10, 2008

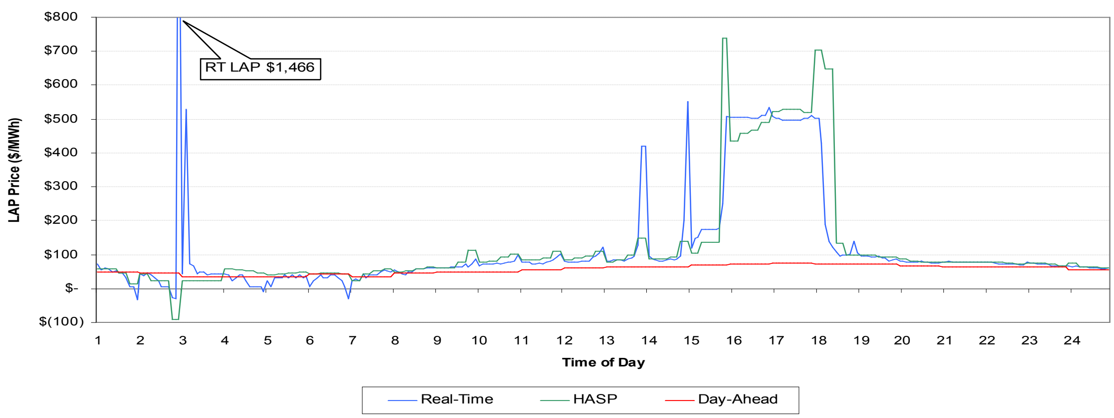
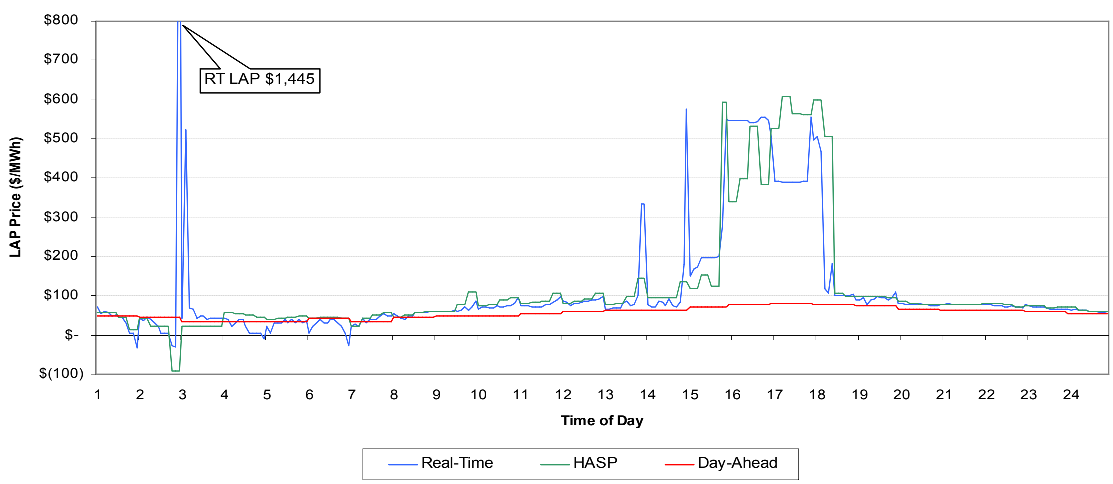


Figure 19. SDG&E LAP Prices (DA, HASP, RTD) - December 10, 2008



Given the scenario, one would expect real time prices across the peak to be generally higher. However, it is somewhat surprising that the real time prices (HASP & RTD) would stay at or above $500/MWh for more sustained periods under this scenario, particularly given that the day-ahead and real-time load forecasts were the same and RUC was committing sufficient capacity to meet the load forecast in real-time. One possible factor contributing to these high prices in HASP and RTD is that significantly less real-time energy was bid into the structured simulations on December 10 compared to December 9. This was also true for December 11 and 12, which may have exacerbated real-time price volatility for those simulations as well (Figure 20). On these days, the combined amount of energy bid from imports and some resources within the CAISO submitted by participants in the HASP was about 1,800 MW lower than on the first day of the structured simulations (December 9). This it is yet another example of the limitations of a market simulation.

Data in Figure 20 also help illustrate why prices tended to spike in the HASP and RTM on December 10-12. As shown in Figure 20, on these days bid prices during Hour Ending 17 rise sharply above $100/MW after the first 53,000 MW of potential supply for real time energy bids. During this hour, the total demand for the supply depicted in Figure 20 averaged about 52,500 MW.[11] However, the aggregated bid curve depicted in Figure 20 overestimates the actual supply of bid energy available for dispatch in the HASP and RTM, since it does not reflect internal CAISO constraints, simultaneous import limits, individual unit constraints (such as various ramping limits and special limits placed on units providing regulation), and the unavailability of any additional import bids in the RTD after the conclusion of the HASP process.[12] These factors would, if accounted for in Figure 20, have the effect of shifting the effective supply curves further to the left. Thus, data in Figure 20 indicate that during the peak hours of these days, once these other various constraints are taken into account, the aggregate supply curve actually available for dispatch in the HASP and RTD had an extremely steep upward slope, so that relatively small increases in demand could create significant spikes in LMPs system wide.

[11] CAISO Load (46,173 MW) + Exports (3,032 MW) + Ancillary Services (3,308 MW) = 52,513 MW.

[12] Aggregated supply curves in Figure 20 are approximated from HASP bids by screening out bids that are not likely to be feasible in the HASP market. These include HASP bids for non-committed units with start-up times greater than one hour, and any import bids in excess of the total available capacity on inter-ties. It should noted that it is likely this approach still overestimates the actual available supply of bid available for dispatch in the HASP and RTM, since it does not reflect internal CAISO constraints, individual unit constraints (such as ramp limits), and capacity reserved for Ancillary Services.

Figure 20. Comparison of Aggregate Real Time Supply Curves (Dec 9-12, Hr 17)

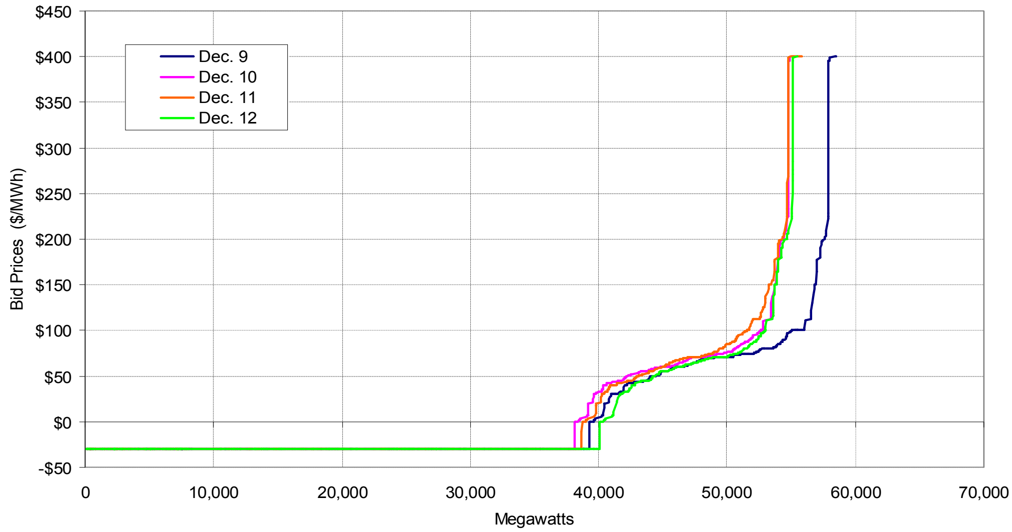


Figure 21 compares the HASP prices for the three LAPs (PG&E, SCE, SDG&E) and shows they were generally the same except for the peak hours (Hours 15-18) where the SDG&E LAP price exhibited some separation. The deviation in the SDG&E LAP price during these hours was likely due to congestion on the Miguel flowgate.

Figure 21. Comparison of HASP LAP Prices (Dec 10, 2008)

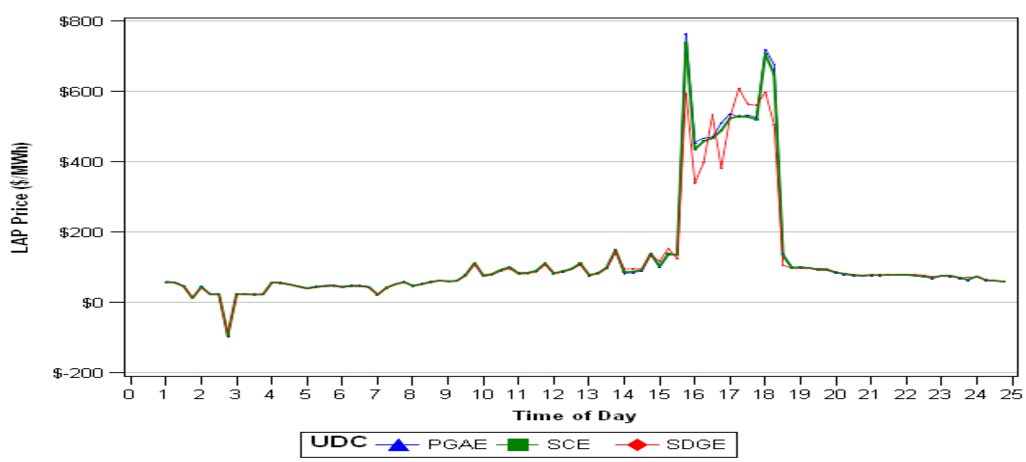


Figure 22 - Figure 24 show the decomposition of HASP LAP prices for PG&E, SCE, and SDG&E, respectively, into the three component of system energy, congestion, and losses. The congestion and loss components of the PG&E and SCE HASP LAP prices were relatively minor. The SDG&E HASP LAP prices had a more significant congestion component, which appears to be primarily related to congestion on the Miguel flowgate.

Figure 22. PG&E HASP LAP Price Decomposition (Dec 10, 2008, Hrs 13-18)

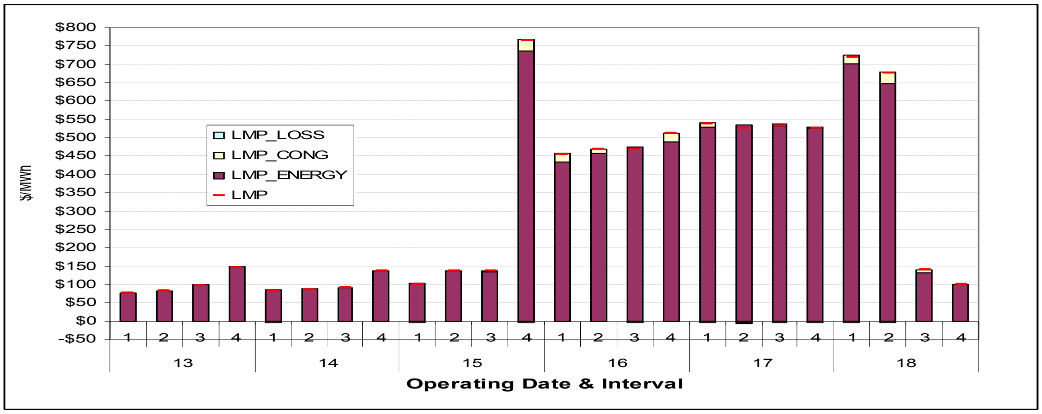


Figure 23. SCE HASP LAP Price Decomposition (Dec 10, 2008, Hrs 13-18)

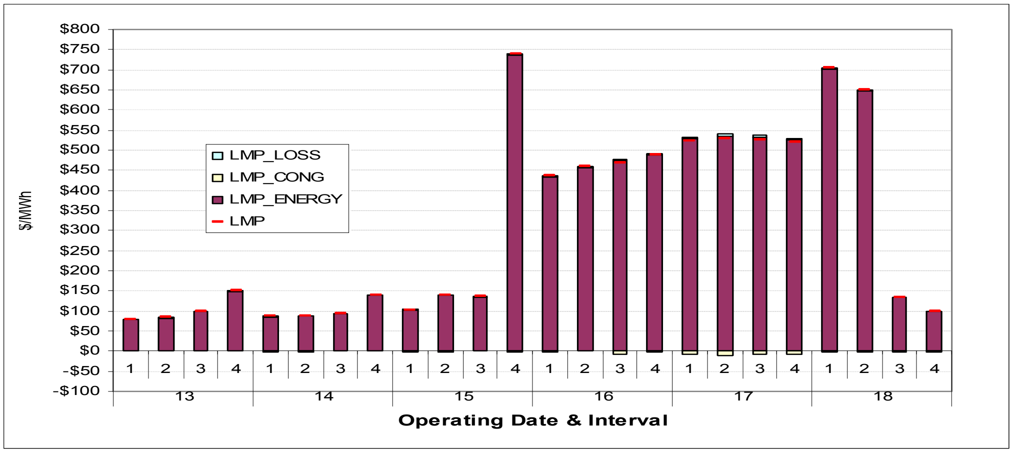


Figure 24. SDG&E HASP LAP Price Decomposition (Dec 10, 2008, Hrs 13-18)

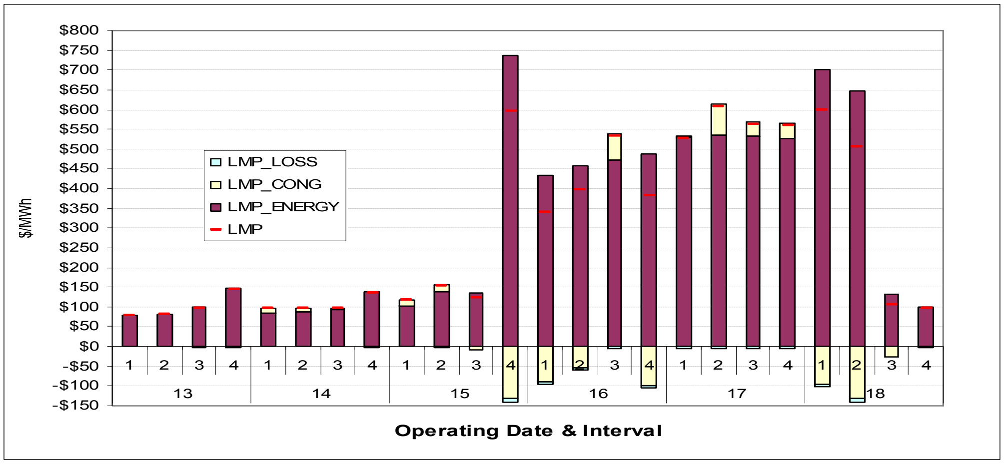


Table 5 provides a list of some of the more frequent and significant binding transmission constraints[13] in HASP during intervals where at least one HASP LAP price exceeded \$200/MWh. Table cells highlighted in aqua indicate flow violations. Flow violations occurred in the HASP on several transmission constraints, Miguel and two constraints on the PG&E system (Chicago Park to Higgins and Morgan Hill to Llagas).

Table 5. HASP Binding Constraints when LAP Price > \$200/MWh (Dec 10)

		Constraint* Shadow Prices** (\$/MW)						LAP Prices (\$/MWh)		
Hour	Interval	Miguel	Imperial Valley	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	PACI Inter-tie	PG&E	SCE	SDG&E
15	1	65	0	0	0	5	92	100	103	117
	2	101	0	70	0	38	126	136	138	154
	3	0	59	78	0	39	126	136	136	125
	4	0	439	1351	528	627	709	764	739	594
16	1	0	206	921	0	338	423	455	436	340
	2	0	312	503	1003	347	431	467	459	397
	3	500	0	549	1003	348	432	470	467	533
	4	0	239	1035	69	383	474	511	489	382
17	1	435	0	1054	1227	411	493	537	524	527
	2	583	0	615	1203	401	484	527	529	608
	3	500	0	869	0	408	492	533	527	563
	4	500	0	834	385	401	485	526	521	560
18	1	0	488	915	1610	583	663	720	705	598
	2	0	338	1378	0	544	627	675	649	505
	3	0	18	272	0	42	128	139	133	106
	4	30	0	93	0	5	92	100	100	97

*** Binding constraints shown are not an exhaustive list**
**** Aqua color indicates constraint violations**

[13] Other binding constraints not shown in Table 5 include the following inter-ties: Standiford, Marble, IID-SCE, Cascade, Silver Peak, North Gila, and Palo Verde.

Figure 25 compares the HASP shadow values of the Miguel constraint to the SDG&E and SCE HASP LAP prices and shows that the SDG&E LAP price was higher than the SCE LAP price when Miguel was congested, but generally lower otherwise.

Figure 25. HASP LAP Prices & Miguel Congestion (Dec 10, Hrs 15-18)

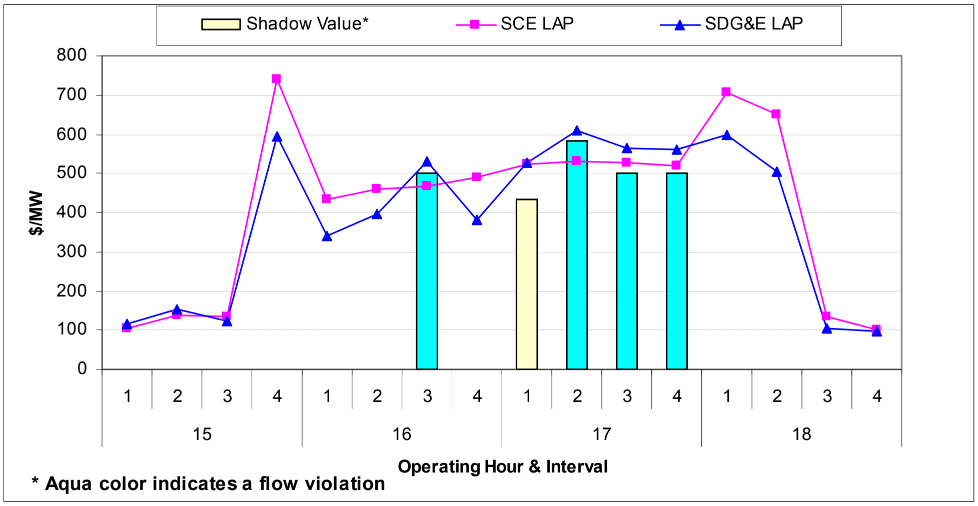
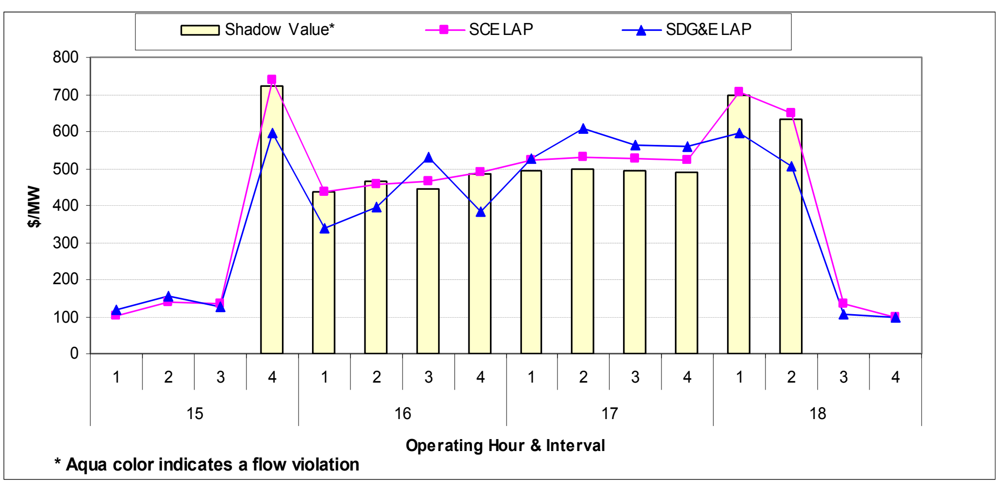


Figure 26 compares the shadow values in HASP for the Imperial Valley to SCE constraint to the HASP LAP prices for SCE and SDG&E. The SCE and SDG&E LAP prices were near identical in the first three intervals of Hour 15, when neither Miguel or Imperial Valley were congested. The SCE LAP price was generally higher than the SDG&E LAP price when Imperial Valley was congested but Miguel was not (e.g., Hour 15, Interval 4, Hour 16, Intervals 1-2).

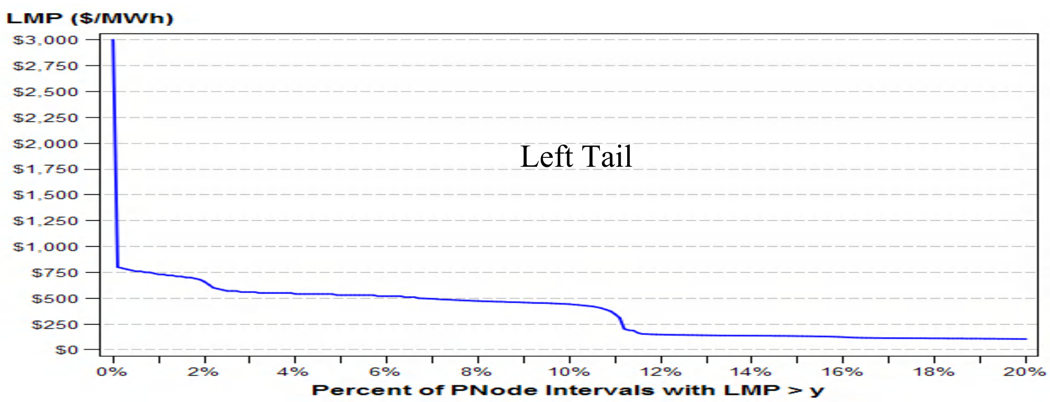
Figure 26. HASP LAP Prices & Imperial Valley[14] Congestion (Dec 10, Hrs 15-18)



[14] IID to SCE Inter-tie Constraint

Figure 27 shows a price duration curve for all the HASP LMPs on December 10. To focus on the frequency of extreme prices, Figure 27 shows just the left and right tails of the price duration curve. As evident in the left tail, the frequency of extreme positive HASP LMPs (i.e., LMPs greater than $500/MWh) was more frequent relative to December 9 – comprising approximately 7 percent of the total HASP LMPs. The right tail of the LMP duration curve (showing the lowest HASP LMPs) indicates that only a small share of HASP LMPs (less than 2 percent) were at or below $0/MWh.

Figure 27. HASP LMP Duration Curve (December 10, 2008)



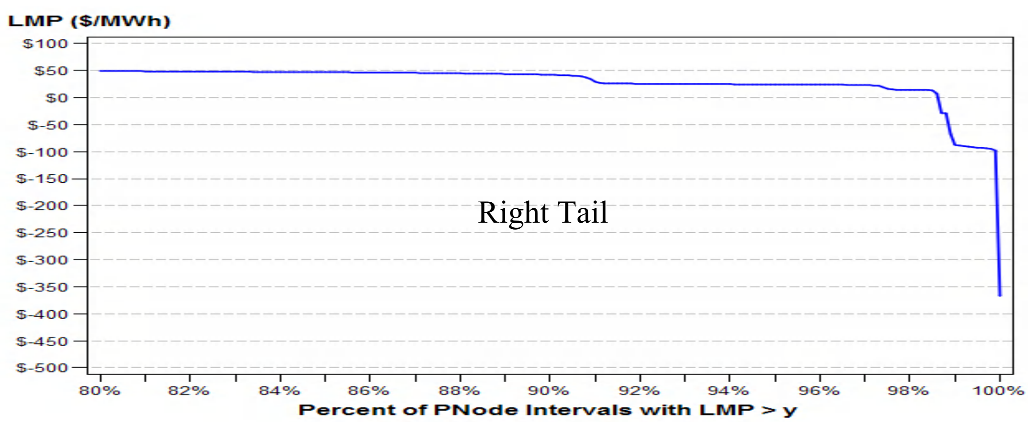


Figure 28 shows the number of P-nodes having HASP LMPs within certain price ranges for each interval of the operating day. Negative HASP LMPs between -$30 and -$100/MWh occurred predominately in Hour 2 - Interval 4. Extreme positive HASP LMPs occurred in most intervals across Hours 15-18. HASP LMPs in excess of the $500 bid cap occurred at most P-Nodes in Hour 17.

Figure 28. HASP LMP Frequencies by Interval (December 10, 2008)

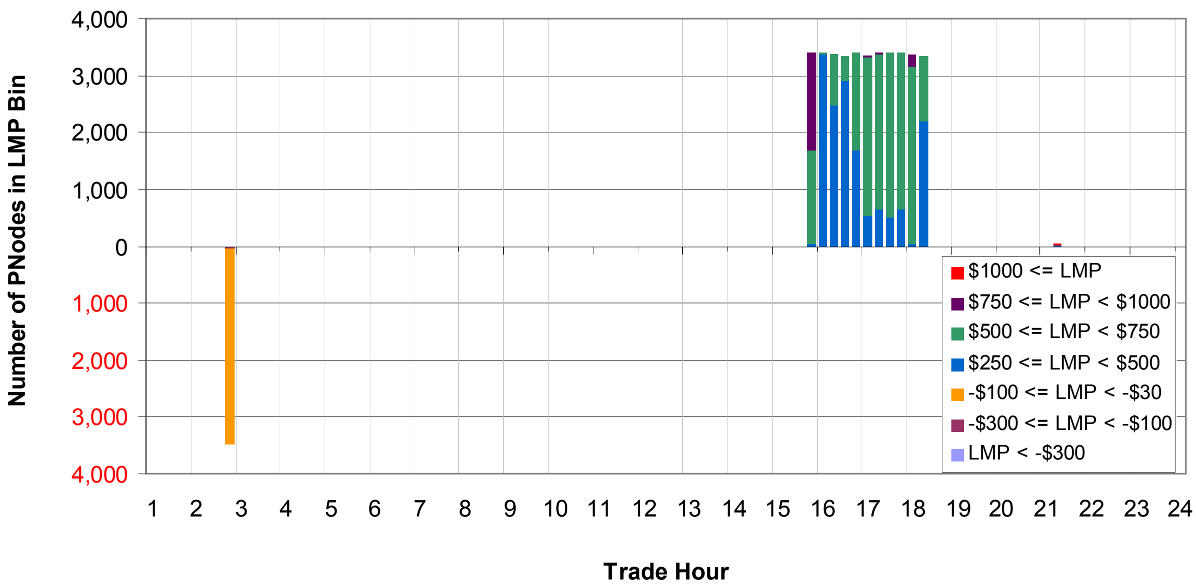


Figure 29 shows a comparison of RTD LAP prices for December 10. The spikes in RTD LAP prices observed in Hours 2 and 3 were due to a glitch in the simulated telemetry. RTD LAP prices across the peak hours were generally at or near $500/MWh, which was generally lower than what was observed in HASP. The SDG&E LAP price separated from the other LAP prices during the peak hours, which appears to be due to Miguel congestion.

Figure 29. Comparison of RTD LAP Prices (Dec 10, 2008)

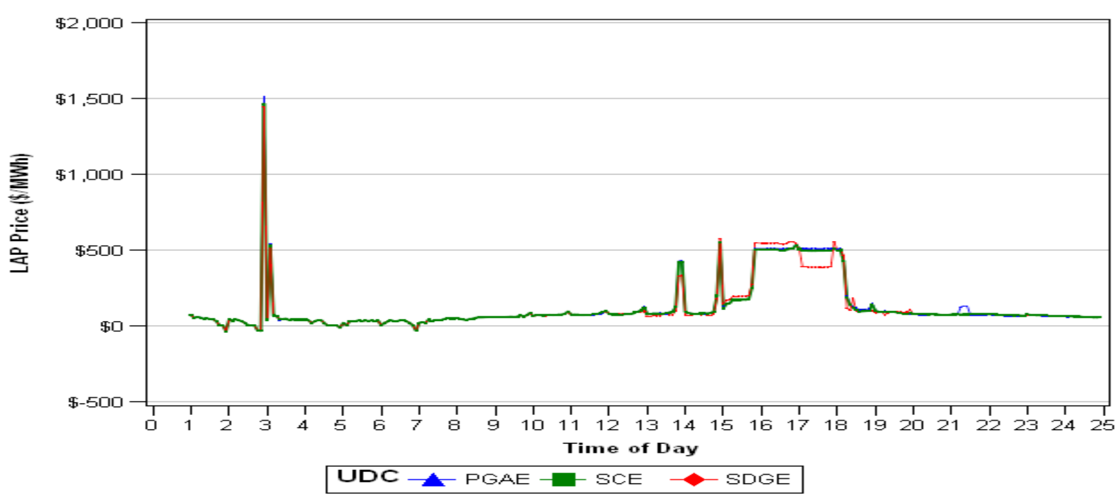


Figure 30 compares the RTD LAP prices for SDG&E and SCE to the shadow values of the Miguel flowgate and demonstrates that the SDG&E LAP price is generally significantly higher than the SCE LAP price when there is congestion at Miguel, particularly in intervals where Miguel experiences flow violations (aqua columns).

Figure 30. RTD LAP Prices and Miguel Congestion (Dec 10, Hrs 14-18)

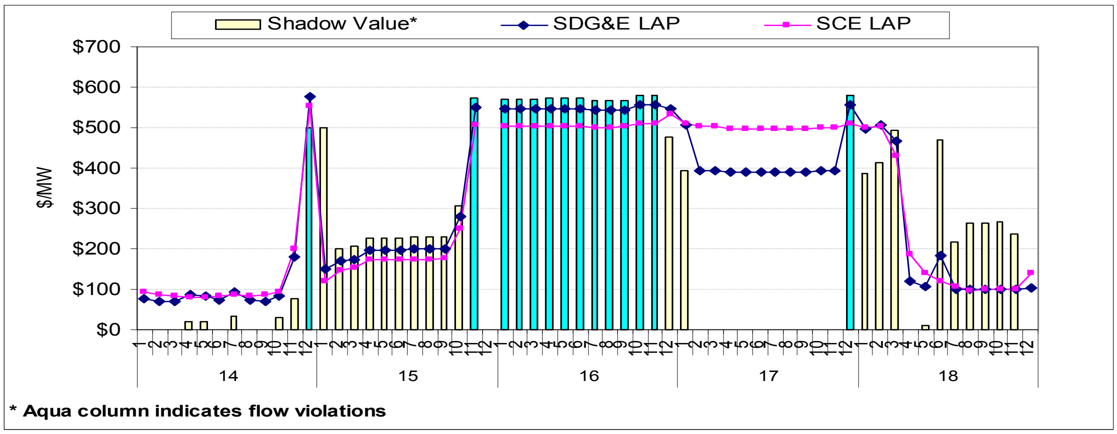


Table 6 shows the shadow values of the transmission constraints that tended to be most frequently congested during intervals of high LAP prices (i.e., >$200/MWh – highlighted in yellow). Table cells highlighted in aqua indicate shadow prices associated with a flow violation. The Miguel flowgate had high shadow prices and flow violations through most of Hour 16. A constraint on the PG&E system (Chicago Park to Higgins) had high shadow prices and flow violations in hours 16 and 17. The Victorville-Lugo nomogram was also binding through most of the peak hours with high shadow prices.

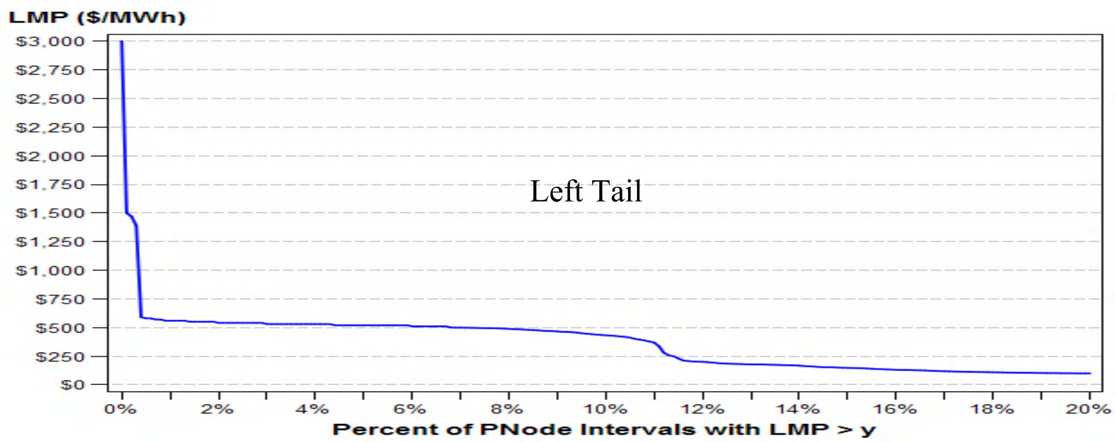
Table 6. RTD Binding Constraints when LAP Price > $200/MWh (Dec 10, Hrs 13-18)

		Constraint Shadow Prices* ($/MW)				LAP Prices ($/MWh)		
Hour	Interval	Miguel	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	PG&E	SCE	SDG&E
13	1	0	161	0	0	84	81	66
	2	0	161	0	0	84	81	66
	3	8	167	0	0	87	84	70
	4	0	137	0	0	86	84	70
	5	0	168	0	0	87	84	68
	6	0	0	0	0	81	82	81
	7	0	0	0	0	85	87	85
	8	0	182	0	0	94	91	74
	9	0	190	0	4	98	95	77
	10	0	258	0	34	130	127	101
	11	0	888	0	319	432	421	334
	12	0	888	0	319	432	421	334
14	1	0	189	0	0	97	95	76
	2	0	175	0	0	90	88	71
	3	0	129	0	0	85	83	71
	4	21	0	0	0	79	82	86
	5	20	28	0	0	79	81	82
	6	0	108	0	0	85	85	74
	7	33	16	0	0	84	86	92
	8	0	108	0	0	85	84	74
	9	0	175	0	0	90	88	71
	10	29	186	0	3	97	95	84
	11	77	408	0	105	205	201	180
	12	500	1,018	0	436	557	553	576
15	1	500	1,010	0	40	136	119	149
	2	201	278	0	52	148	147	169
	3	205	288	0	56	153	152	174
	4	228	332	0	75	176	174	197
	5	228	332	0	75	176	174	197
	6	228	332	0	75	176	174	197
	7	229	335	0	78	177	175	198
	8	229	335	0	78	177	175	198
	9	231	338	0	80	179	177	200
	10	308	487	550	151	254	251	279
	11	574	1,005	0	396	513	507	550
	12	0	0	0	0			
16	1	571	1,001	0	395	512	505	547
	2	571	1,001	0	395	512	505	547
	3	571	1,001	0	395	512	505	547
	4	572	1,001	1,117	394	513	505	548
	5	572	1,001	1,117	394	513	505	548
	6	572	1,001	1,117	394	513	505	548
	7	565	991	1,116	388	512	501	542
	8	565	991	1,116	388	512	501	542
	9	568	996	0	390	513	503	544
	10	580	1,014	0	398	516	511	556
	11	580	1,014	0	398	516	511	556
	12	477	1,075	0	422	542	535	548
17	1	395	1,028	0	396	515	509	506
	2	0	1,061	0	396	515	502	393
	3	0	1,061	0	396	515	502	393
	4	0	1,051	1,129	392	512	497	389
	5	0	1,051	1,129	392	512	497	389
	6	0	1,051	1,129	392	512	497	389
	7	0	1,052	1,128	388	512	498	389
	8	0	1,052	1,128	388	512	498	389
	9	0	1,052	1,128	388	512	498	389
	10	0	1,059	0	395	514	501	392
	11	0	1,059	0	395	514	501	393
	12	579	1,012	0	395	514	511	555
18	1	386	1,016	1,230	393	513	502	497
	2	414	1,014	1,132	393	513	502	505
	3	493	848	0	321	434	429	467
	4	0	730	0	103	205	188	119
	5	11	367	0	50	149	141	108
	6	470	579	0	31	129	121	183
	7	217	655	0	24	120	107	100
	8	263	662	0	13	109	96	100
	9	262	688	0	17	113	100	100
	10	266	713	0	19	114	100	100
	11	236	642	0	19	114	101	100
	12	1	399	0	52	149	141	103

* Aqua color indicates constraint violations

Figure 31 shows the left and right tails of the RTD LMP duration curve for December 10. Approximately 6 percent of the total RTD LMPs for December 10 were in excess of $500/MWh. RTD LMPs in excess of $1,000/MWh were limited to less than half a percent of total RTD LMPs. Extreme negative RTD LMPs (right tail) were also less than half a percent of all RTD LMPs.

Figure 31. RTD LMP Duration Curve (December 10, 2008)



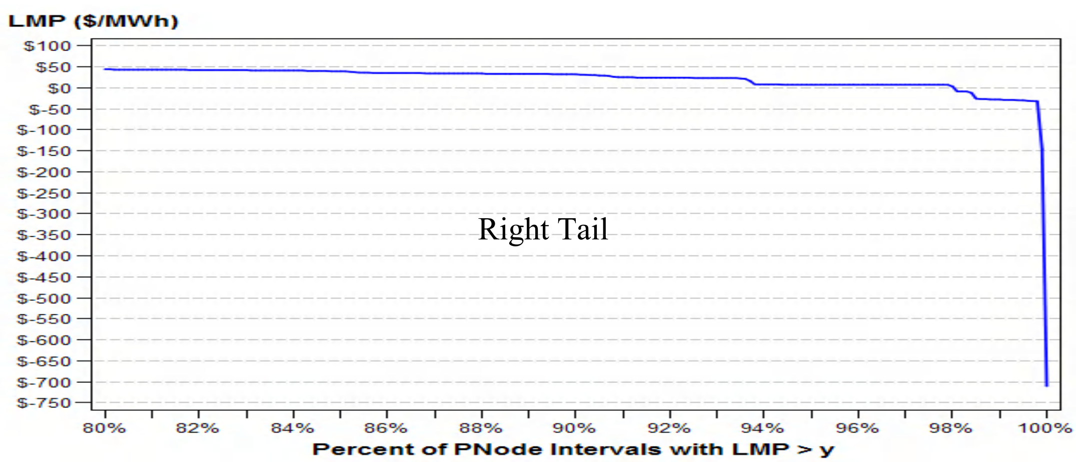
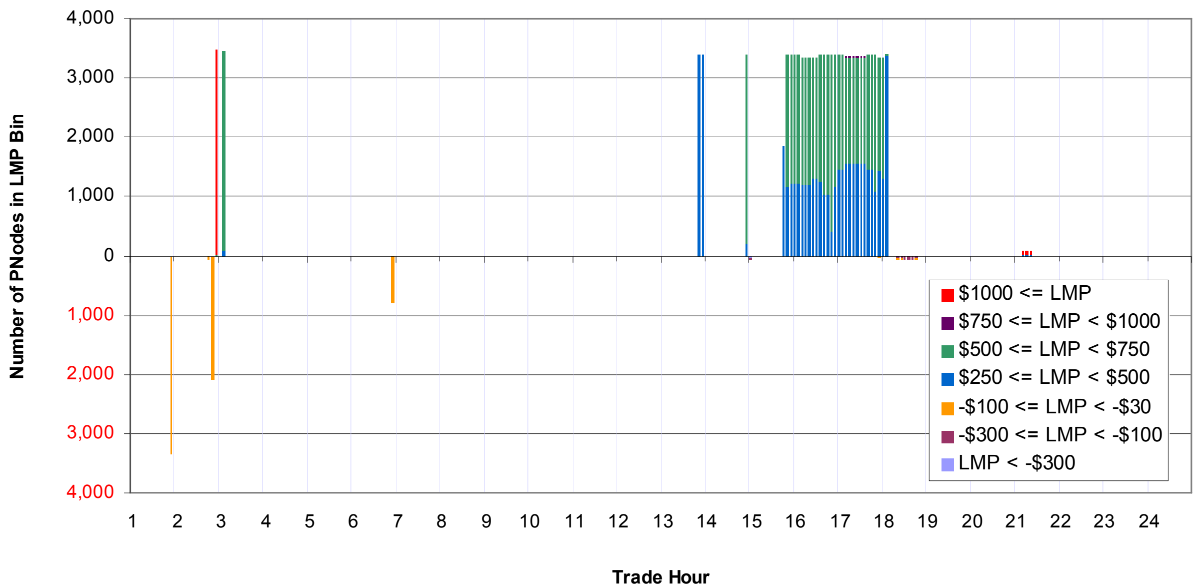


Figure 32 shows the number of P-Nodes experiencing relatively extreme prices for each RTD interval for December 10 and demonstrates that when high LMPs occurred, they tended to occur throughout the system. LMPs in excess of $1,000/MWh occurred primarily in Hour 2 and, as previously noted, these were due to a glitch in the simulated telemetry.

Figure 32. RTD LMP Frequencies by Interval (December 10, 2008)



December 11, 2008

The structured simulation for December 11 involved modeling strategic bidding at select load pockets to test the effectiveness of the local market power mitigation. Specifically, energy bids from select generating units in the Los Angeles Basin, San Francisco Bay Area, Big Creek/Ventura area, and San Diego were increased to $400/MWh. The specific details of this economic withholding scenario are described in Section IV of this report.

Figure 33 - Figure 35 compare the Day Ahead, HASP, and RTD LAP prices for PG&E, SCE, and SDG&E, respectively. The high RTD price spikes observed in hours 4 and 5 were due to a glitch in the simulation telemetry. Day Ahead, HASP, and RTD LAP prices showed reasonable price convergence for much of the day with some exceptions. Similar to the previous days, HASP and RTD LAP prices increased significantly across the peak hours but were generally not as high as the LAP prices observed on December 10. The high day-ahead LAP prices observed for SDG&E were the result of a poor quality of solution for the IFM, which resulted in not committing a specific Reliability Must Run (RMR) generating unit in San Diego that was committed under the local market power mitigation procedures. When this day-ahead scenario was re-run offline and allowed to run longer to converge to a better quality solution, an additional RMR unit was committed and the SDG&E LAP prices were more inline with the other LAP prices.

Figure 33. PG&E LAP Prices (DA, HASP, RTD) - December 11, 2008

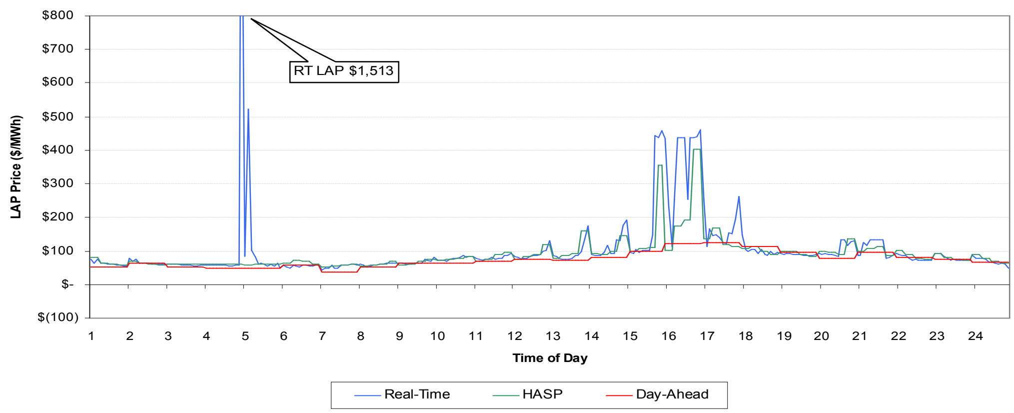


Figure 34. SCE LAP Prices (DA, HASP, RTD) - December 11, 2008

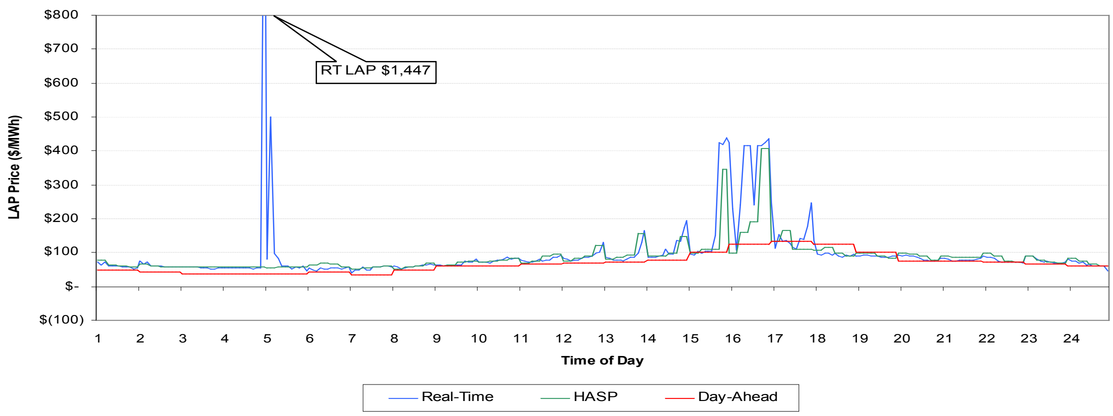


Figure 35. SDG&E LAP Prices (DA, HASP, RTD) - December 11, 2008

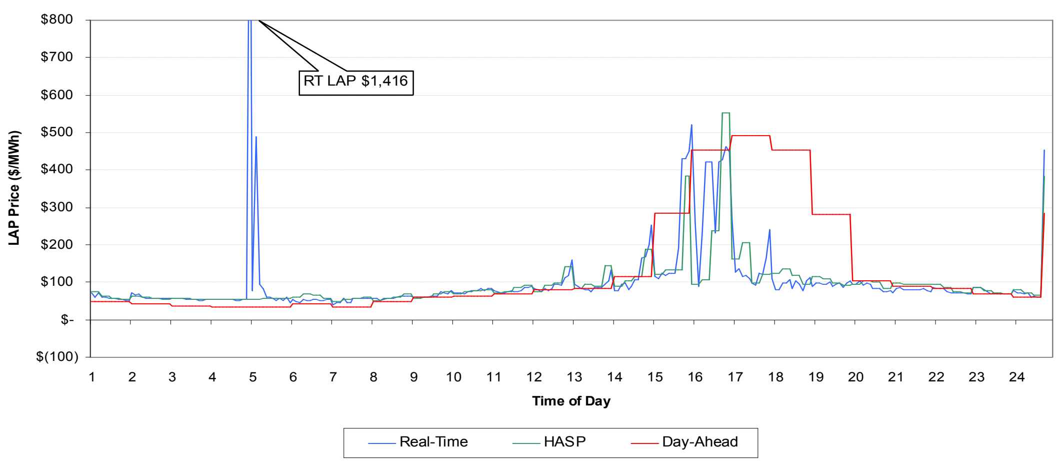


Figure 36 compares the HASP LAP prices for PG&E, SCE, and SDG&E. The PG&E and SCE HASP LAP prices were very similar for most HASP intervals. The SDG&E LAP followed a similar pattern to the other two LAPs but tended to be higher during the peak hours. Again, this trend appears to be primarily due to congestion at Miguel.

Figure 36. Comparison of HASP LAP Prices (December 11, 2008)

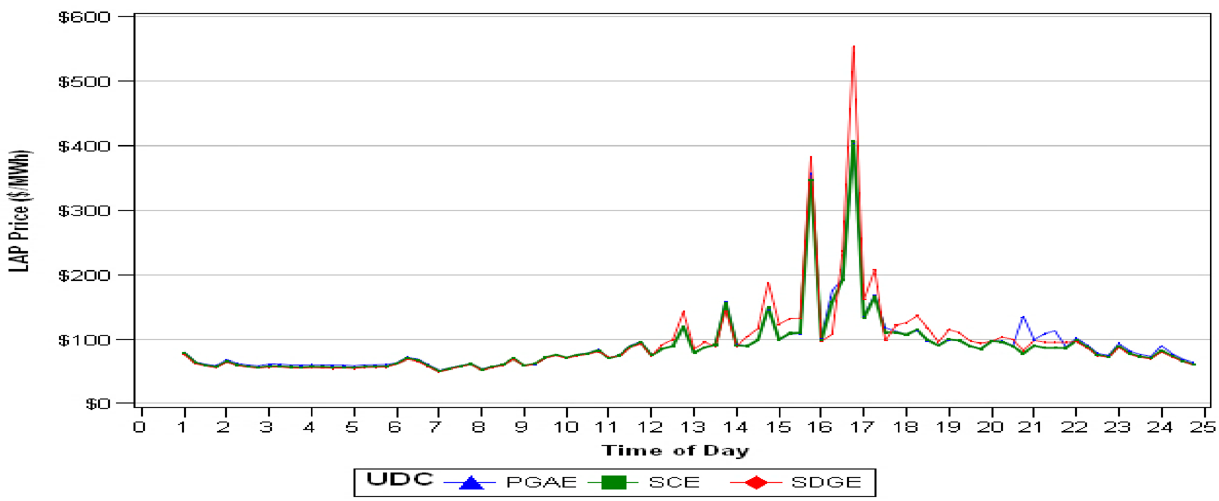


Figure 37 - Figure 39 show the decomposition of the HASP LAP prices for hours 12-18. The congestion component of the HASP LAP prices was relatively minor in comparison to the total LAP price – though the SDG&E LAP price had a more significant congestion component than the other two LAPs.

Figure 37. PG&E HASP LAP Price Decomposition (Dec 11, 2008, Hrs 12-18)

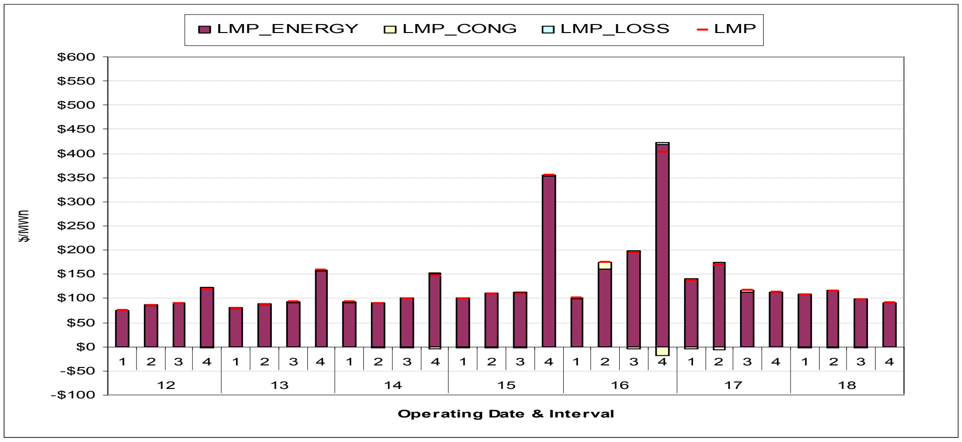


Figure 38. SCE HASP LAP Price Decomposition (Dec 11, 2008, Hrs 12-18)

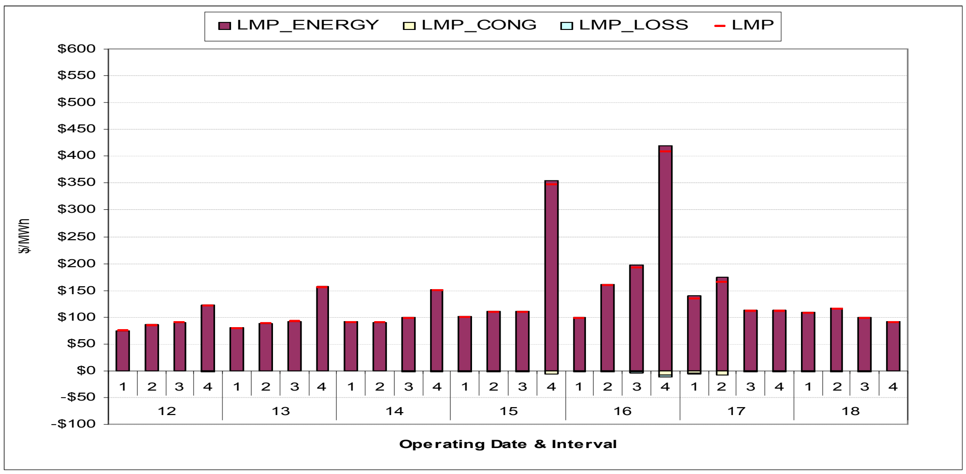


Figure 39. SDG&E HASP LAP Price Decomposition (Dec 11, 2008, Hrs 12-18)

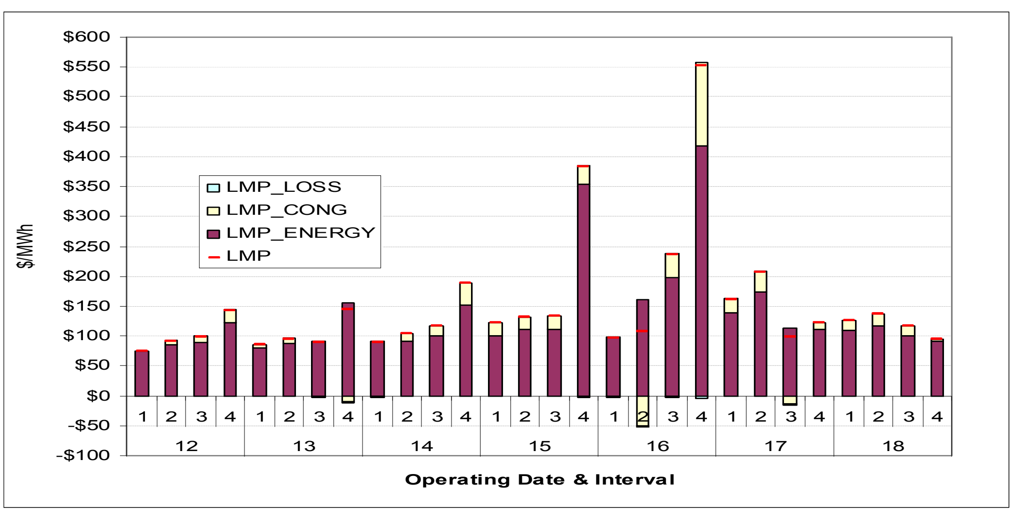


Figure 40 shows the left and right tail of the HASP LMP duration curve for December 11. There were very few extreme HASP LMPs. HASP LMPs in excess of $500/MWh comprised less than half a percent of total HASP LMPs. The same was true for the number of negative HASP LMPs.

Figure 40. HASP LMP Duration Curve (December 11, 2008)

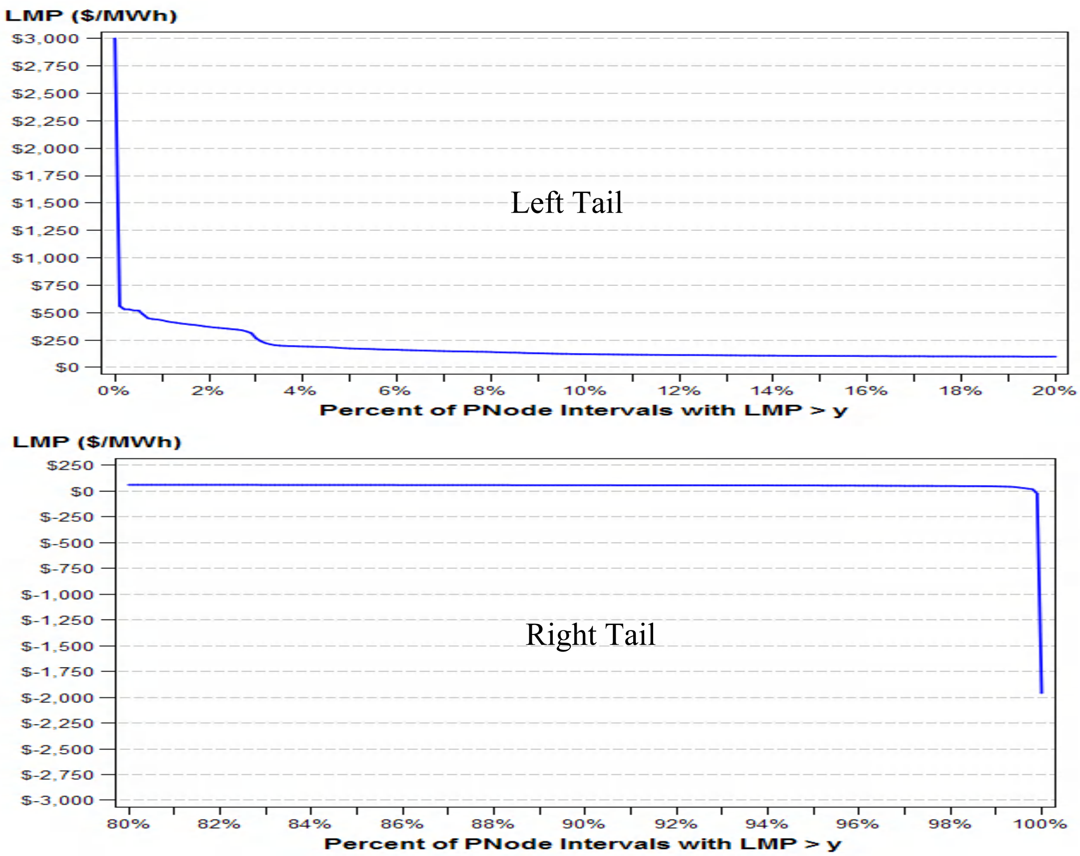


Figure 41 provides a count of the number of P-Nodes having HASP LMPs within certain price ranges for each interval of the day. Most of the HASP LMPs between \$500/MWh and \$750/MWh occurred in Hour 5, interval 2. The majority of HASP LMPs between \$250/MWh and \$500/MWh occurred across the peak hours. There were also a small number of high HASP LMPs occurring in Hours 20 and 21.

Figure 41. HASP LMP Frequencies by Interval (December 11, 2008)

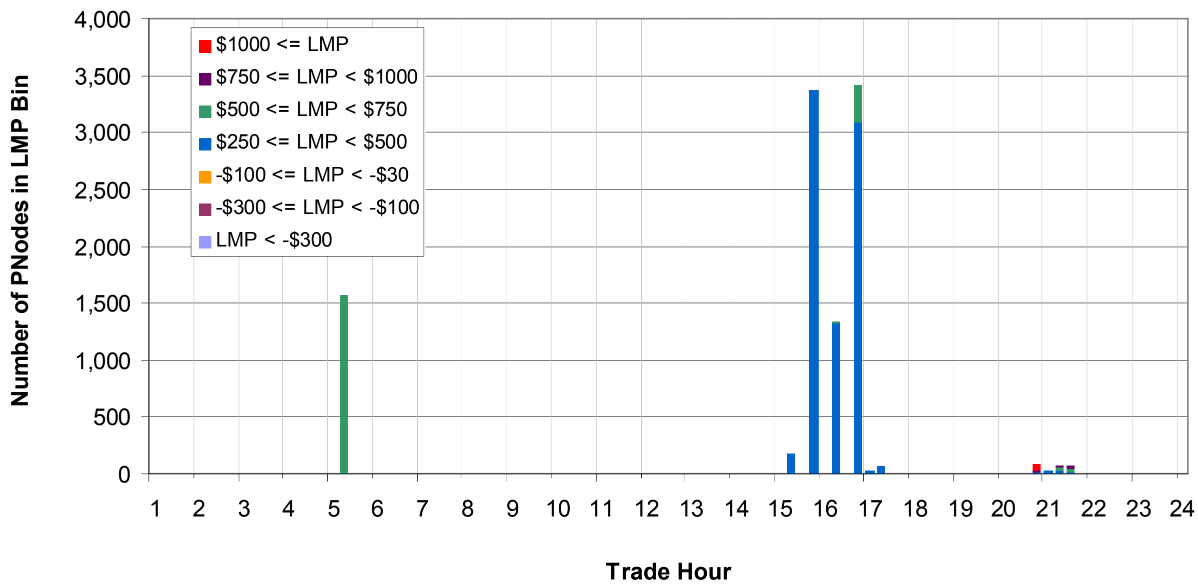


Table 7 provides a list of some of the more frequent and significant binding transmission constraints[15] in HASP during intervals where at least one HASP LAP price exceeded \$200/MWh. Table cells highlighted in aqua indicate flow violations. Flow violations were observed on Miguel and on a PG&E constraint (Birds Landing to Contra Costa).

[15] Other binding constraints not shown in Table 7 include the following inter-ties: Standiford, Marble, Cascade, Silver Peak, PACI, North Gila, Parker, and Palo Verde.

Table 7. HASP Binding Constraints when LAP Price > $200/MWh (Dec 11)

Hour	Interval	Constraint* Shadow Prices** ($/MW) Miguel	Birds Landing - Contra Costa	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	Imperial Irrig. Distr.-SCE Inter-tie	LAP Prices ($/MWh) PG&E	SCE	SDG&E
15	1	96	0	0	0	5	121	98	99	123
	2	93	0	0	0	13	132	108	109	132
	3	94	0	0	0	14	132	109	110	133
	4	328	0	482	0	246	340	356	347	383
16	1	37	0	116	0	7	121	102	98	96
	2	0	0	555	0	77	173	175	158	108
	3	204	0	59	0	93	205	194	192	237
	4	596	0	0	0	289	394	403	407	553
17	1	117	1590	0	0	52	153	136	133	162
	2	172	2421	0	0	90	182	169	165	207
	3	19	424	192	0	26	133	118	111	98
	4	64	0	48	0	17	133	112	110	122

* Binding constraints shown are not an exhaustive list
** Aqua color indicates constraint violations

Figure 42 provides a comparison of RTD LAP prices for December 11. As previously noted, the extreme RTD LAP prices observed in Hours 4 and 5 were due to a glitch in the simulated telemetry. All three RTD LAP prices were closely aligned through much of the day and peaked between $400 and $500/MWh across the peak hours of the day.

Figure 42. Comparison of RTD LAP Prices (December 11, 2008)

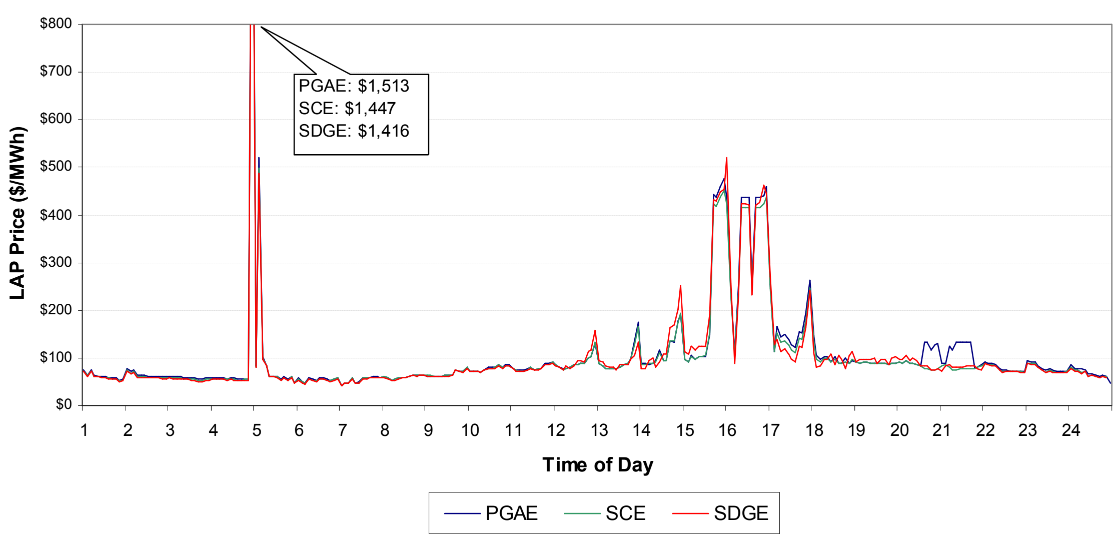


Table 8 lists the transmission constraints that were most frequently binding during periods of high RTD LAP prices (>$200/MWh) for Hours 14-15 and Table 9 provides the same data for Hours 15-16. Constraints that had flow violations are highlighted in aqua. High RTD LAP prices are highly correlated with high shadow prices for several transmission constraints, the Victorville to Lugo Nomogram, Miguel, and Birds Landing to Contra Costa.

Table 8. RTD Binding Constraints when LAP Price > $200/MWh (Dec 11, Hrs 14-15)

		Constraint Shadow Prices* ($/MW)						LAP Prices ($/MWh)		
Hour	Interval	Miguel	Vict. Lugo Nomogram	Brdsldg - C.Costa	NOB Inter-tie	Cascade Inter-tie	Morgan Hill - Llagas	PG&E	SCE	SDG&E
14	1	5	106	0	0	0	0	89	86	78
	2	0	88	0	0	0	0	88	86	78
	3	26	0	0	0	0	0	87	88	94
	4	43	0	0	0	0	0	88	89	99
	5	5	134	0	0	0	0	95	92	81
	6	0	221	1,022	0	0	0	117	110	90
	7	53	0	0	0	0	0	94	95	108
	8	53	0	0	0	0	0	94	95	108
	9	117	0	1,465	0	0	48	135	135	164
	10	137	0	0	0	0	36	132	134	169
	11	155	130	2,335	0	0	95	177	173	201
	12	231	0	2,287	0	0	109	192	193	251
15	1	72	0	0	0	0	2	96	96	114
	2	65	0	203	0	0	0	92	92	109
	3	82	0	864	131	0	16	104	103	124
	4	76	0	0	126	89	3	97	98	117
	5	83	0	0	130	92	7	101	102	123
	6	85	0	0	132	93	8	103	104	125
	7	85	0	0	0	94	9	103	104	125
	8	165	0	0	178	136	52	149	151	192
	9	341	858	649	409	389	332	442	424	431
	10	351	849	0	405	400	323	437	419	430
	11	368	884	994	421	395	349	459	438	449
	12	341	915	2,314	433	380	375	476	452	455

* Aqua color indicates constraint violations

Table 9. RTD Binding Constraints when LAP Price > $200/MWh (Dec 11, Hrs 16-17)

		Constraint Shadow Prices* ($/MW)						LAP Prices		
Hour	Interval	Miguel	Vict. Lugo Nomogram	Brdsldg - C.Costa	NOB Inter-tie	Cascade Inter-tie	Morgan Hill - Llagas	PG&E	SCE	SDG&E
16	1	605	580	0	0	428	0	436	424	521
	2	206	250	0	245	246	0	237	230	258
	3	6	217	2,286	126	134	0	114	107	89
	4	147	486	2,267	245	232	150	253	240	233
	5	334	843	2,394	401	400	323	437	415	422
	6	334	843	2,370	401	400	323	437	415	422
	7	333	843	1,441	402	400	323	438	415	422
	8	146	486	1,446	245	232	150	254	240	232
	9	333	843	2,462	402	400	323	438	415	422
	10	348	841	2,301	401	400	323	438	415	427
	11	404	667	3,016	416	402	325	440	423	463
	12	358	886	400	420	421	344	460	437	446
17	1	213	311	0	258	262	150	254	246	270
	2	75	32	0	140	134	19	114	113	129
	3	49	304	0	166	127	84	167	153	137
	4	26	261	0	147	108	62	145	132	115
	5	30	268	0	150	108	67	148	135	118
	6	20	250	0	142	100	58	139	126	109
	7	11	232	0	134	110	40	126	116	98
	8	6	221	0	129	105	35	121	111	92
	9	36	281	0	156	112	74	155	142	125
	10	34	275	0	153	113	69	152	139	122
	11	74	353	0	188	135	114	194	178	164
	12	153	500	0	251	260	160	262	247	240

* Aqua color indicates constraint violations

Figure 43 shows the left and right tails of the RTD LMP duration curve for December 11. RTD LMPs in excess of $500/MWh comprised less than 1 percent of the total RTD LMPs. The same was true for negative RTD LMPs.

Figure 43. RTD LMP Duration Curve (December 11, 2008)

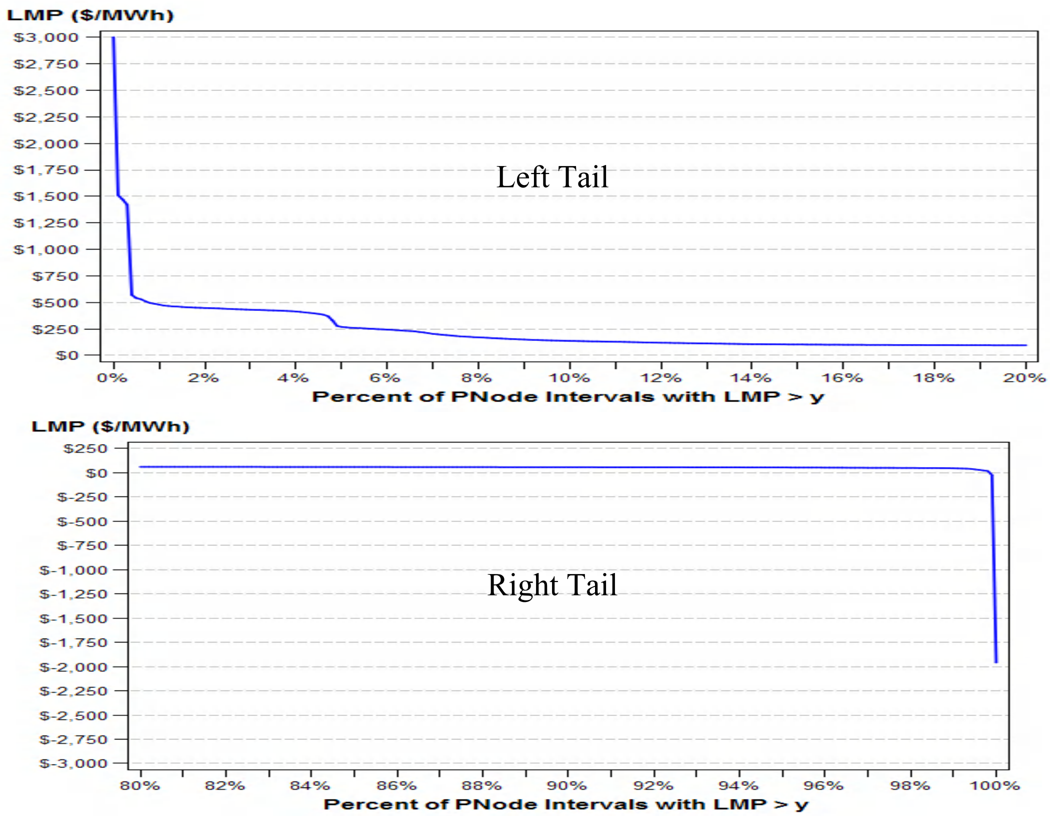
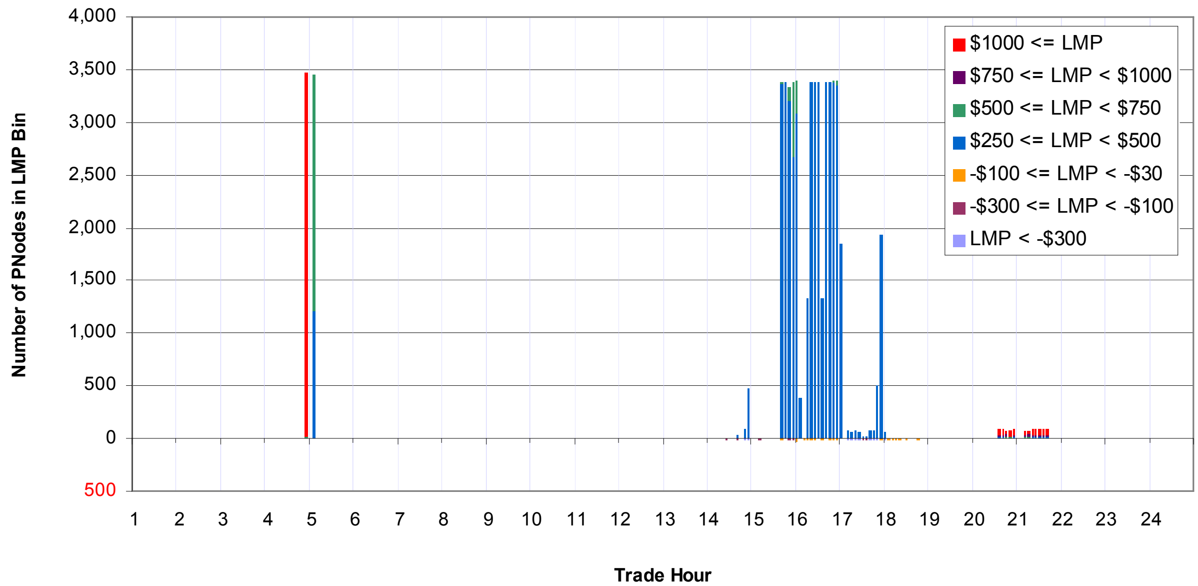


Figure 44 lists the number of RTD LMPs that occurred in specific price ranges for each interval of the day. The extreme RTD LMPs observed in Hour 4 were due to telemetry issues. The majority of RTD LMPs between $250/MWh and $500/MWh occurred across the peak hours of the day and tended to be system-wide in Hours 15-16. There were also a small number of extreme LMPs in Hours 20 and 21.

Figure 44. RTD LMP Frequencies by Interval (December 11, 2008)



December 12, 2008

The December 12 structured simulation was the same as December 9 except that the real-time load forecast was increased to be 5 percent higher than the day-ahead load forecast. This increase was imposed in both HASP and RTD. With a peak day-ahead load forecast of 46,000 MW, the 5 percent forecast increase in real-time added another 2,300 MW of real-time demand. Additionally, as was previously discussed and demonstrated in Figure 20, the amount of supply bids offered to the real-time market (HASP and RTD) on December 12 was significantly less than what was offered on December 9. The combination of these two events (higher loads, less supply) created severe shortages in the HASP and RTD and resulted in very extreme prices system-wide.

We do not consider the structured scenario for this day to be very realistic and the extreme results observed are more reflective of the limitations of the simulation as opposed to what we would expect in actual market operation. Specifically, if the CAISO experienced such a significant increase in real-time energy demand in actual operation on a peak summer day, we believe that there would be a significant market response of increased supply, particularly at the inter-ties, which would mitigate extreme prices, whereas the structured simulation had essentially no supply response. Moreover, such an extreme event would likely trigger demand response programs, which did not happen under the structured simulation. The extreme prices observed in the simulation for this day appear to reflect various transmission constraint violations.

Figure 45 - Figure 47 show the Day Ahead, HASP, and RTD LAP prices for PG&E, SCE, and SDG&E, respectively. Similar to past days, all three LAPs exhibited similar pricing patterns with very extreme LAP prices in HASP and RTD across the peak hours – often in excess of $2,000/MWh. HASP LAP prices were generally much higher than RTD LAP prices across the peak hours, with the highest HASP LAP price at approximately $7,000/MWh in Hour 20.

Figure 45. PG&E LAP Prices (DA, HASP, RTD) - December 12, 2008

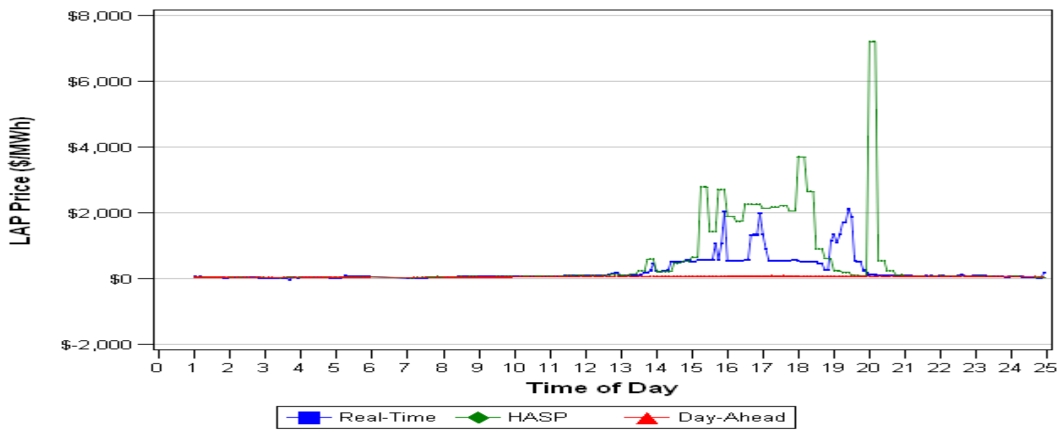


Figure 46. SCE LAP Prices (DA, HASP, RTD) - December 12, 2008

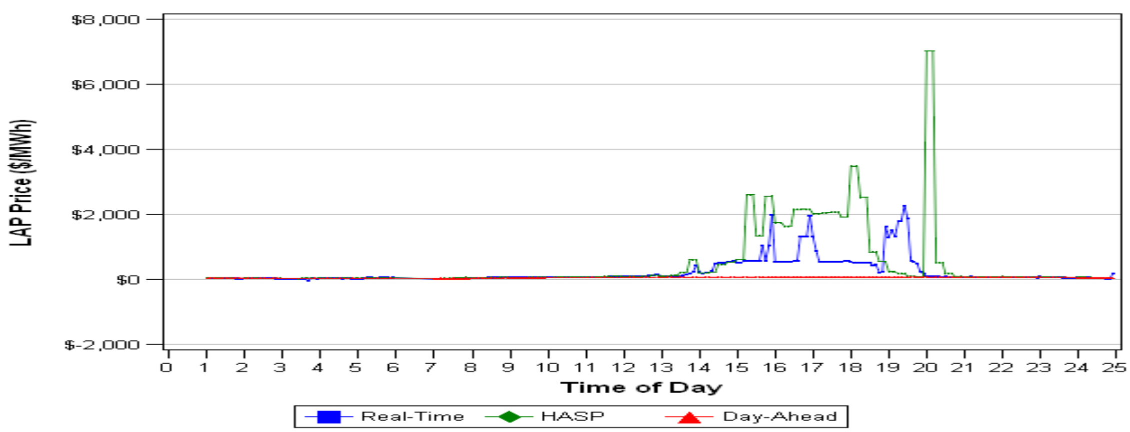


Figure 47. SDG&E LAP Prices (DA, HASP, RTD) - December 12, 2008

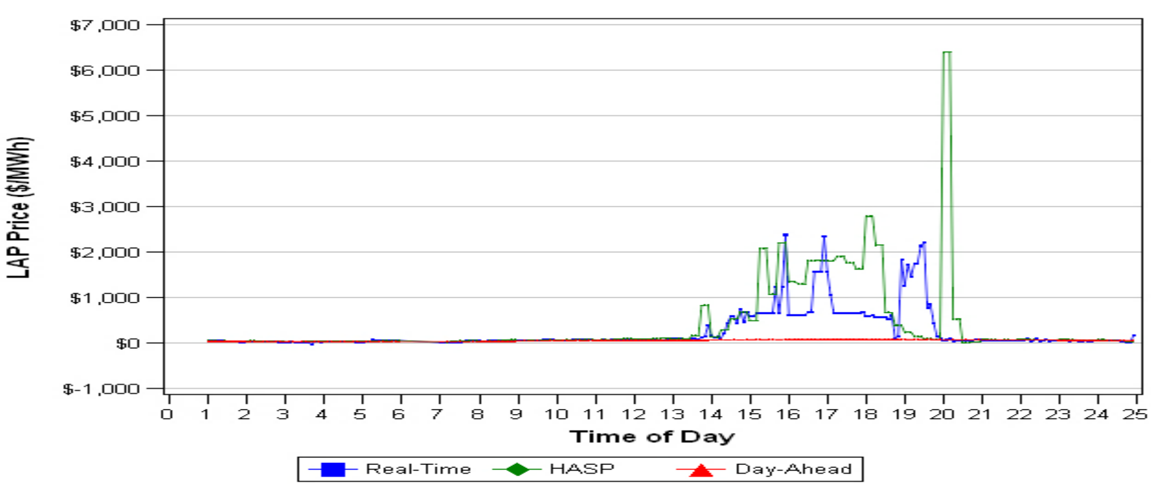


Figure 48 compares HASP LAP prices for PG&E, SCE, and SDG&E. Consistent with prior days, the PG&E and SCE LAP prices followed almost identical patterns and the SDG&E LAP price showed more separation, especially across the peak hours where the SDG&E LAP price in HASP was significantly lower.

Figure 48. Comparison of HASP LAP Prices (December 12, 2008)

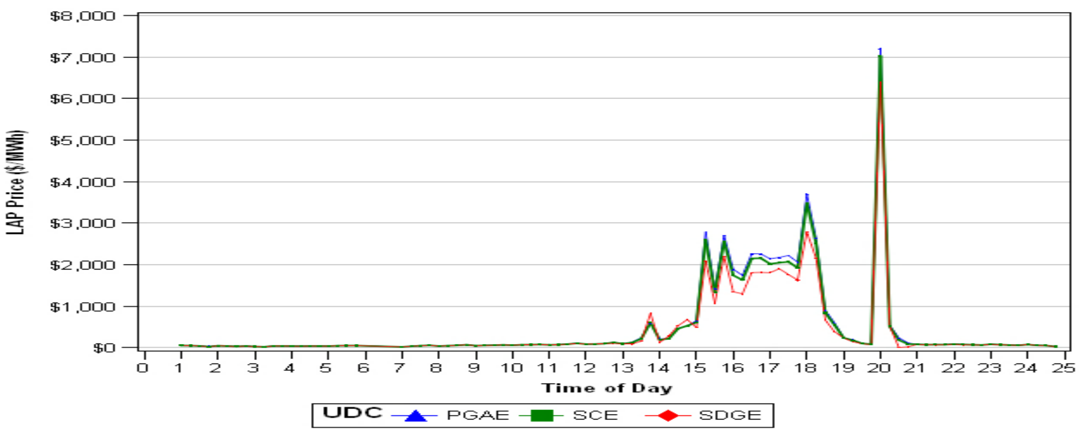


Figure 49 - Figure 51 show the decomposition of the HASP LAP prices for PG&E, SCE, and SDG&E, respectively. Though difficult to discern from the scale of the chart, the PG&E HASP LAP had a fairly significant positive congestion component during intervals with extreme prices, particularly Hour 20, interval 1. Conversely, the SDG&E HASP LAP price had a more significant and negative congestion component. The SCE HASP LAP prices had relatively minor congestion components.

Figure 49. PG&E HASP LAP Decomposition (Dec 12, 2008, Hrs 13-19)

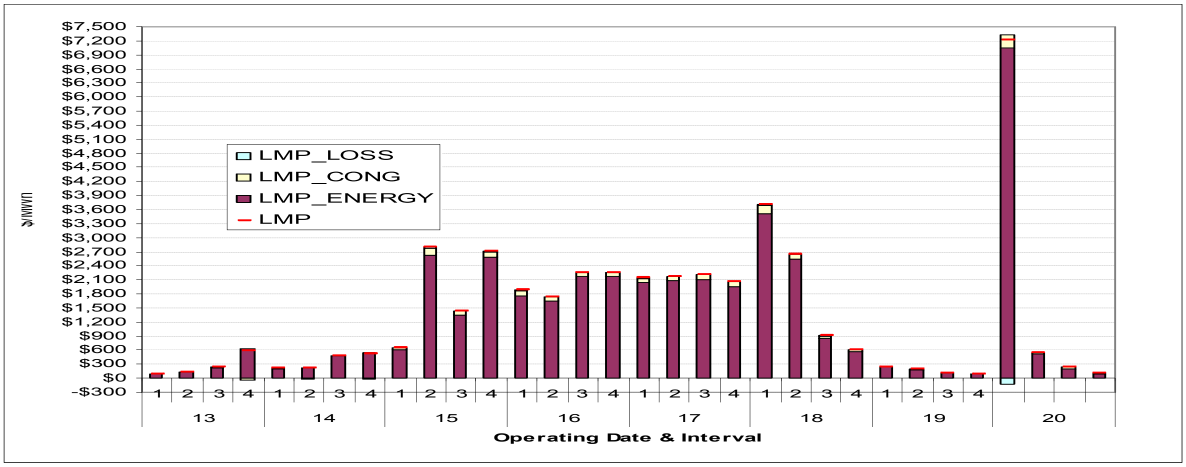


Figure 50. PG&E HASP LAP Decomposition (Dec 12, 2008, Hrs 13-19)

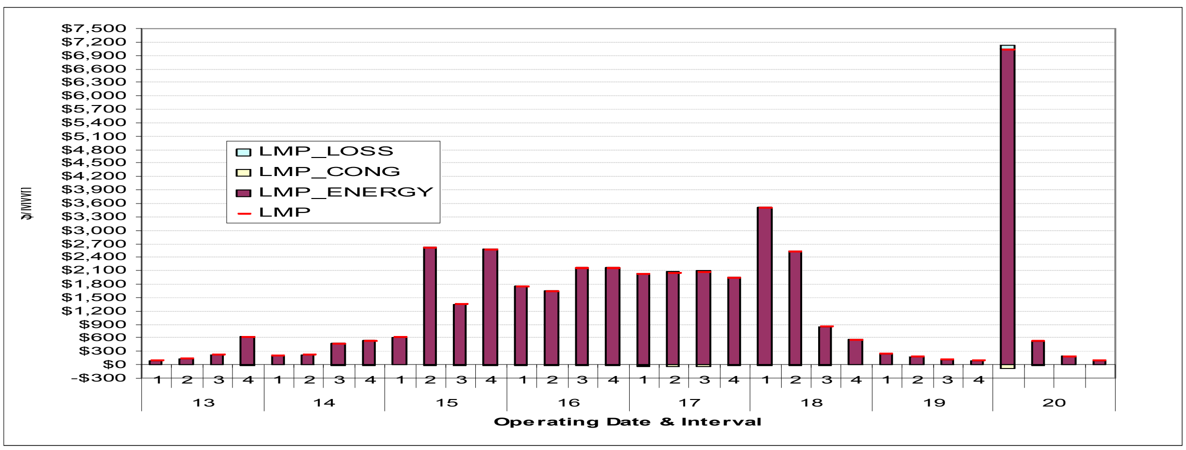


Figure 51. SCE HASP LAP Decomposition (Dec 12, 2008, Hrs 13-19)

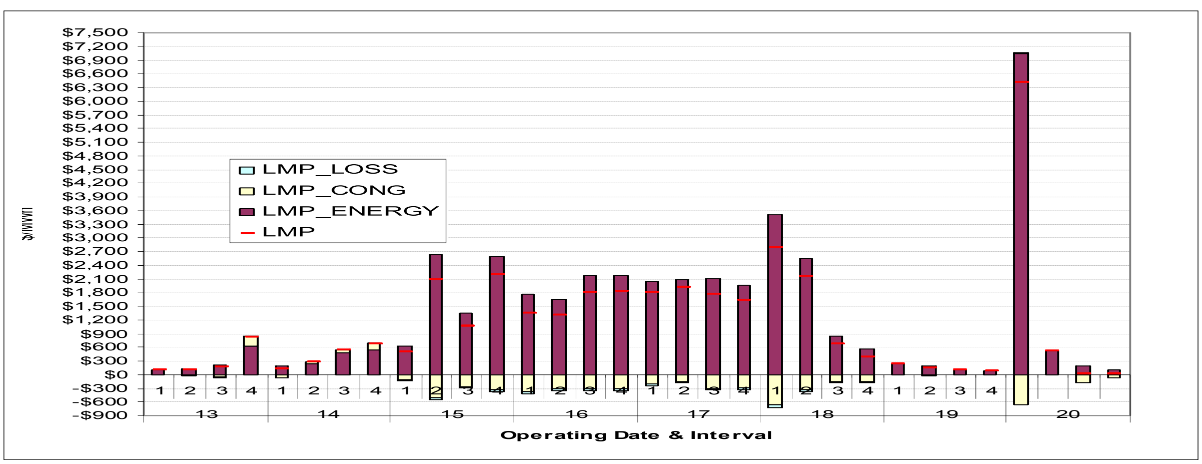


Table 10 provides a list of some of the more frequent and significant binding transmission constraints[16] in HASP during intervals where at least one HASP LAP price exceeded $200/MWh. Table cells highlighted in aqua indicate flow violations.

Table 10. HASP Binding Constraints when LAP Price > $200/MWh (Dec 12)

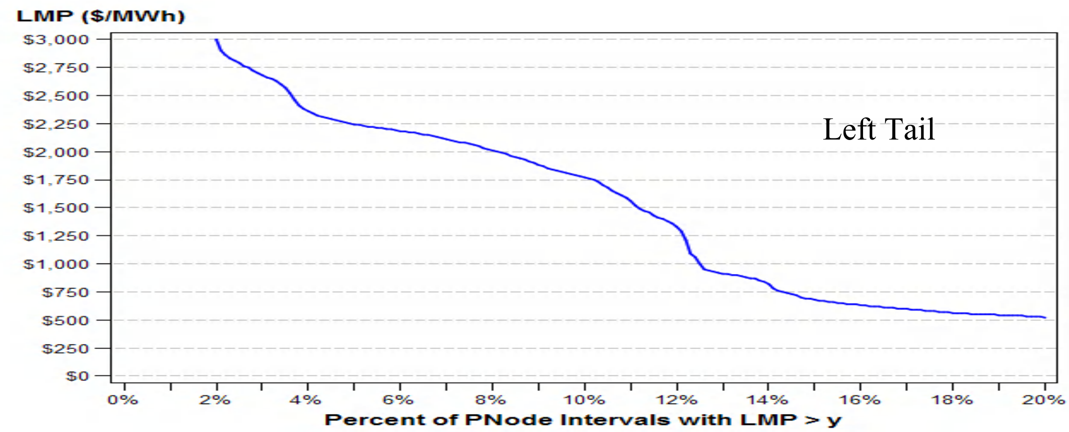
		Constraint* Shadow Prices** ($/MW)						LAP Prices ($/MWh)		
Hour	Interval	Miguel	Cragview - Cascade	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	PACI Inter-tie	PG&E	SCE	SDG&E
13	1	0	631	0	0	6	121	99	97	97
	2	0	0	339	0	41	158	138	127	96
	3	34	0	733	0	138	254	242	220	162
	4	921	0	0	0	465	577	595	608	831
14	1	0	0	707	0	113	229	215	195	131
	2	267	958	0	0	114	230	218	221	286
	3	500	0	549	44	351	465	472	462	532
	4	711	0	256	1148	404	514	529	532	681
15	1	0	531	1301	1369	522	633	653	612	490
	2	0	0	5577	7105	584	2584	2794	2606	2084
	3	0	500	2859	500	613	1343	1432	1341	1073
	4	55	514	3754	5301	560	2503	2711	2561	2204
16	1	0	409	4139	8394	423	1722	1890	1746	1350
	2	0	436	3476	3655	444	1599	1746	1634	1300
	3	0	0	3467	2310	444	2074	2263	2152	1812
	4	0	420	3493	500	442	2072	2261	2158	1816
17	1	0	400	500	3973	422	1954	2143	2021	1810
	2	326	407	500	4040	431	1982	2177	2049	1906
	3	0	410	1412	4031	436	2027	2224	2072	1765
	4	0	0	1595	2754	402	1889	2064	1925	1631
18	1	0	500	7250	3969	720	3423	3705	3488	2791
	2	0	500	3726	5543	493	2447	2650	2527	2157
	3	0	500	1791	4112	500	853	904	843	670
	4	0	500	1744	1284	476	590	609	554	391
19	1	0	0	0	0	137	252	242	241	239
	2	0	0	377	0	92	208	193	182	147
	3	0	0	65	0	14	129	107	105	98
	4	0	0	131	0	0	116	94	89	77
20	1	0	500	500	1447	1572	6624	7210	7033	6399
	2	437	408	1044	12065	392	569	546	517	527
	3	0	0	1961	521	140	256	242	187	10
	4	0	0	760	1328	24	137	118	94	25

*** Binding constraints shown are not an exhaustive list**
**** Aqua color indicates constraint violations**

[16] Other binding constraints not shown in Table 10 include the following inter-ties: Standiford, Marble, IID-SCE, Cascade, Silver Peak, North Gila, Blythe, and Palo Verde.

Figure 52 shows the left and right tails of the HASP LMP duration curve for December 12. The left tail (extreme positive LMPs) is truncated at $3,000/MWh. Approximately 20 percent of the HASP LMPs on December 12 exceeded $500/MWh with roughly 12 percent exceeding $1,000/MWh. There were very few extreme negative LMPs (less than 1 percent).

Figure 52. HASP LMP Duration Curve (December 12, 2008)



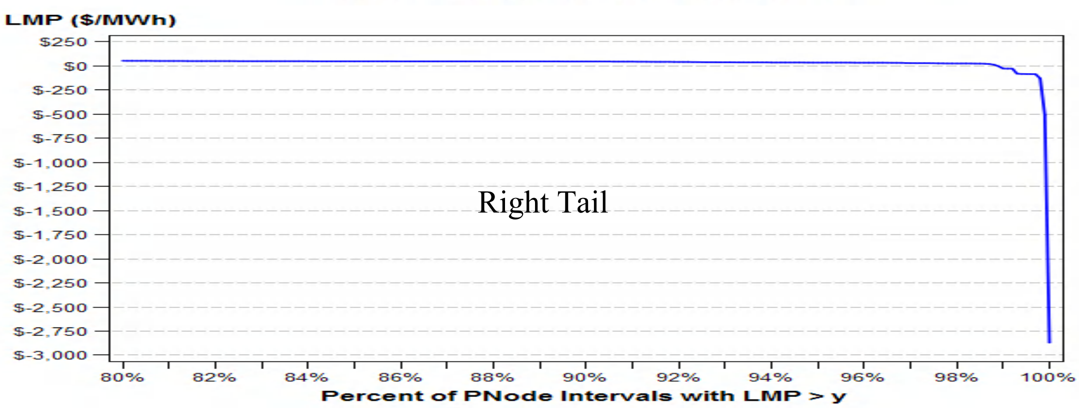


Figure 53 provides a count of the number of P-Nodes with HASP LMPs within certain price ranges for each interval of the day. HASP LMPs in excess of $1,000/MWh occurred primarily in the super peak hours of 15 to 17 and tended to occur throughout the system.

Figure 53. HASP LMP Frequencies by Interval (December 12, 2008)

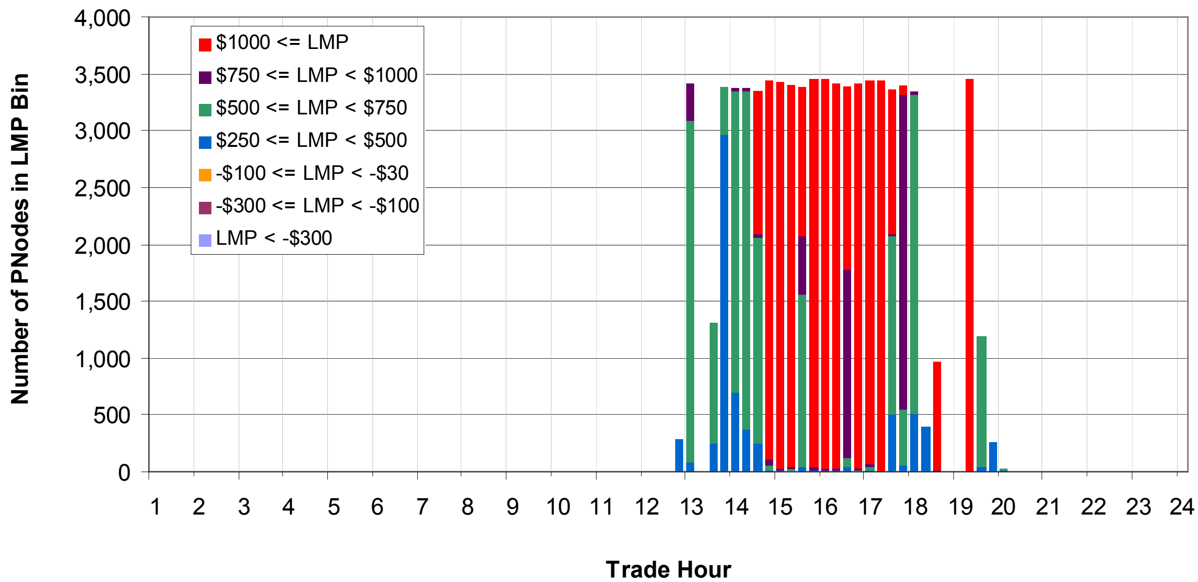


Figure 54 compares RTD LAP prices for December 12. The PG&E and SCE LAP prices were more closely aligned than SDG&E. Higher RTD LAP prices for SDG&E across the peak hours appear to be associated with Miguel congestion.

Figure 54. Comparison of RTD LAP Prices (December 12, 2008)

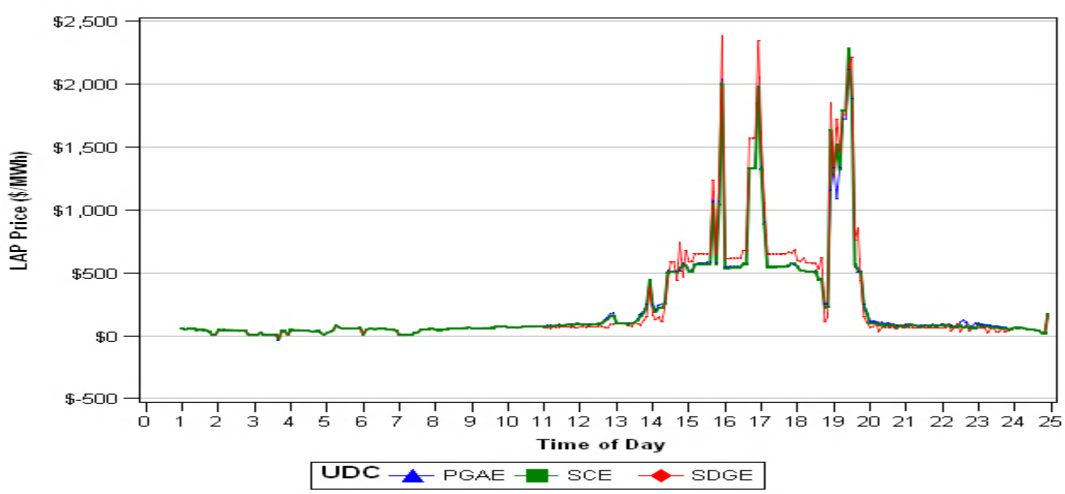


Table 11 provides a list of the transmission constraints that most frequently binding in RTD during interval where HASP LAP prices exceeded $200/MWh for Hours 13-16 and Table 12 shows the same data for Hours 17-19. Constraints that incurred flow violations are highlighted in aqua. As evident from these tables, numerous transmission constraints were binding in RTD during the peak hours of December 12 and several of them had flow violations. These binding constraints were likely a major factor in causing the extreme LAP prices. Further in-depth analysis for selected hours would be required to determine the extent to which each of these constraints contributed to extreme RTD LAP prices.

Table 11. RTD Binding Constraints when LAP Price > $200/MWh (Dec 12, Hrs 13-16)

		Constraint Shadow Prices* ($/MW)									LAP Prices ($/MWh)		
Hour	Interval	Miguel	Vict. Lugo Nomogram	IID - SCE Inter-tie	Rio-Oso	Brdsldg - C.Costa	Chicago Prk - Higgins	PACI Inter-tie	Cragview - Cascade	Morgan Hill - Llagas	PG&E	SCE	SDG&E
13	11	0	904	0	120	0	0	0	0	152	254	233	151
	12	0	571	0	276	0	997	0	0	337	450	441	388
14	1	0	693	0	115	0	0	0	0	145	247	230	167
	2	0	667	0	80	0	0	0	0	106	205	189	128
	3	0	825	0	93	2,100	497	0	0	159	247	223	147
	4	0	1,233	0	113	0	546	0	0	147	252	221	109
	5	0	345	0	119	402	562	0	0	160	262	255	222
	6	0	644	0	323	748	1,109	0	0	398	515	502	440
	7	554	633	0	328	0	1,120	0	0	391	513	509	586
	8	555	635	0	335	751	0	0	0	399	516	512	588
	9	0	646	0	335	751	0	0	0	399	516	504	442
	10	0	0	0	333	0	1,132	0	0	402	521	540	738
	11	812	939	20	370	829	1,234	0	0	458	575	555	469
	12	718	689	0	362	814	1,211	0	0	448	564	562	675
15	1	624	784	0	329	0	1,223	0	0	397	516	509	589
	2	623	783	0	324	750	1,214	0	0	403	518	509	589
	3	626	696	0	364	1,165	1,326	0	0	456	571	565	653
	4	620	695	0	367	1,413	1,340	0	0	459	579	566	650
	5	620	695	0	367	1,413	1,340	0	0	459	579	566	650
	6	620	695	0	367	1,413	1,340	0	0	459	579	566	650
	7	620	695	0	0	1,490	1,345	3	0		583	566	650
	8	620	695	0	0	1,490	1,345	3	0		583	566	650
	9	1,288	1,246	416	0	1,499	2,425	446	0		1,070	1,044	1,238
	10	619	694	0	0	1,511	1,345	4	0	463	583	566	650
	11	1,285	1,242	414	0	1,500	2,421	445	0	912	1,067	1,042	1,235
	12	2,503	2,384	1,254	0	500	500	419	0	1,810	2,037	2,000	2,380
16	1	583	661	0	354	0	1,276	0	459		551	536	613
	2	583	661	0	354	0	1,276	0	459		551	536	613
	3	586	664	0	354	0	1,273	0	459		551	540	616
	4	586	664	0	0	0	1,273	0	459		551	540	616
	5	586	664	0	0	0	1,273	0	459		551	540	616
	6	586	664	0	0	0	1,273	0	459		551	540	616
	7	718	697	0	374	0	1,329	22	482	445	574	571	677
	8	718	697	0	374	0	1,329	22	482	445	574	571	677
	9	1,622	1,575	668	995	0	2,992	716	1,195	1,152	1,335	1,330	1,567
	10	1,625	1,571	666	995	0	2,993	456	1,196	1,152	1,336	1,329	1,569
	11	1,625	1,571	666	995	0	2,993	456	1,196	1,152	1,336	1,329	1,569
	12	2,468	2,313	1,229	1,490	0	3,740	1,302	1,800	1,752	1,982	1,973	2,345

* Aqua color indicates constraint violations

Table 12. RTD Binding Constraints when LAP Price > $200/MWh (Dec 12, Hrs 17-19)

		Constraint Shadow Prices* ($/MW)									LAP Prices		
Hour	Interval	Miguel	Vict. Lugo Nomogram	IID - SCE Inter-tie	Rio-Oso	Brdsldg - C.Costa	Chicago Prk - Higgins	PACI Inter-tie	Cragview - Cascade	Morgan Hill - Llagas	PG&E	SCE	SDG&E
17	1	1,616	1,563	660	0	0	2,986	713	1,193	0	1,341	1,321	1,560
	2	1,101	1,064	280	0	0	2,036	317	785	0	903	890	1,053
	3	690	668	0	0	0	1,275	0	459	423	551	547	649
	4	690	668	0	0	0	1,275	0	459	0	553	547	649
	5	690	668	0	0	0	1,275	0	459	0	553	547	649
	6	690	668	0	0	0	1,275	0	459	0	553	547	649
	7	692	669	0	0	0	1,275	0	0	423	550	547	650
	8	692	669	0	0	0	1,275	0	0	423	550	547	650
	9	692	669	0	0	0	1,275	0	0	423	550	547	650
	10	705	681	0	0	0	1,311	0	0	430	552	556	662
	11	691	903	0	0	0	1,366	22	0	453	577	575	658
	12	725	700	0	0	0	1,347	15	0	445	569	573	682
18	1	538	864	0	0	0	1,316	0	0	429	553	547	594
	2	626	792	0	0	0	1,239	0	0	397	519	515	591
	3	660	639	0	0	0	1,239	0	0	397	519	520	618
	4	544	630	0	0	0	1,242	0	0	390	515	509	578
	5	544	630	0	0	0	1,242	0	0	390	515	509	578
	6	544	630	0	0	0	1,242	0	0	390	515	509	578
	7	542	628	0	0	0	1,240	0	0	389	514	506	575
	8	569	554	0	0	0	1,098	0	0	330	451	445	529
	9	919	547	0	0	0	1,098	0	0	330	451	451	621
	10	0	1,201	0	0	0	658	0	0	150	257	223	112
	11	0	882	0	0	0	658	0	0	150	257	232	149
	12	500	0	500	0	0	500	462	0	0	1,161	1,635	1,846
19	1	500	1,593	708	1,011	0	3,019	722	0	1,153	1,340	1,301	1,265
	2	500	300	500	500	0	500	499	0	500	1,092	1,519	1,722
	3	500	500	691	500	0	500	724	0	500	1,339	1,319	1,465
	4	500	500	1,050	1,230	0	500	915	0	0	1,721	1,788	1,756
	5	500	500	1,050	1,230	0	500	915	0	0	1,721	1,788	1,756
	6	500	2,755	1,581	837	0	500	0	0	0	2,115	2,280	2,135
	7	2,283	2,216	1,149	0	0	500	1,234	0	1,668	1,888	1,869	2,211
	8	837	28	0	0	0	0	5	0	423	549	563	760
	9	1,330	0	0	0	0	0	0	0	389	513	535	856
	10	0	642	0	340	0	0	0	0	389	513	499	437
	11	0	891	0	121	0	82	0	0	149	255	232	150

* Aqua color indicates constraint violations

Figure 55 shows the left and right tails of the RTD LMP duration curve for December 12. Approximately 17 percent of the RTD LMPs were in excess of $500/MWh and roughly 5 percent were in excess of $1,000/MWh. Extreme negative RTD LMPs were rare, comprising less than 1 percent of the total RTD LMPs.

Figure 55. RTD LMP Duration Curve (December 12, 2008)

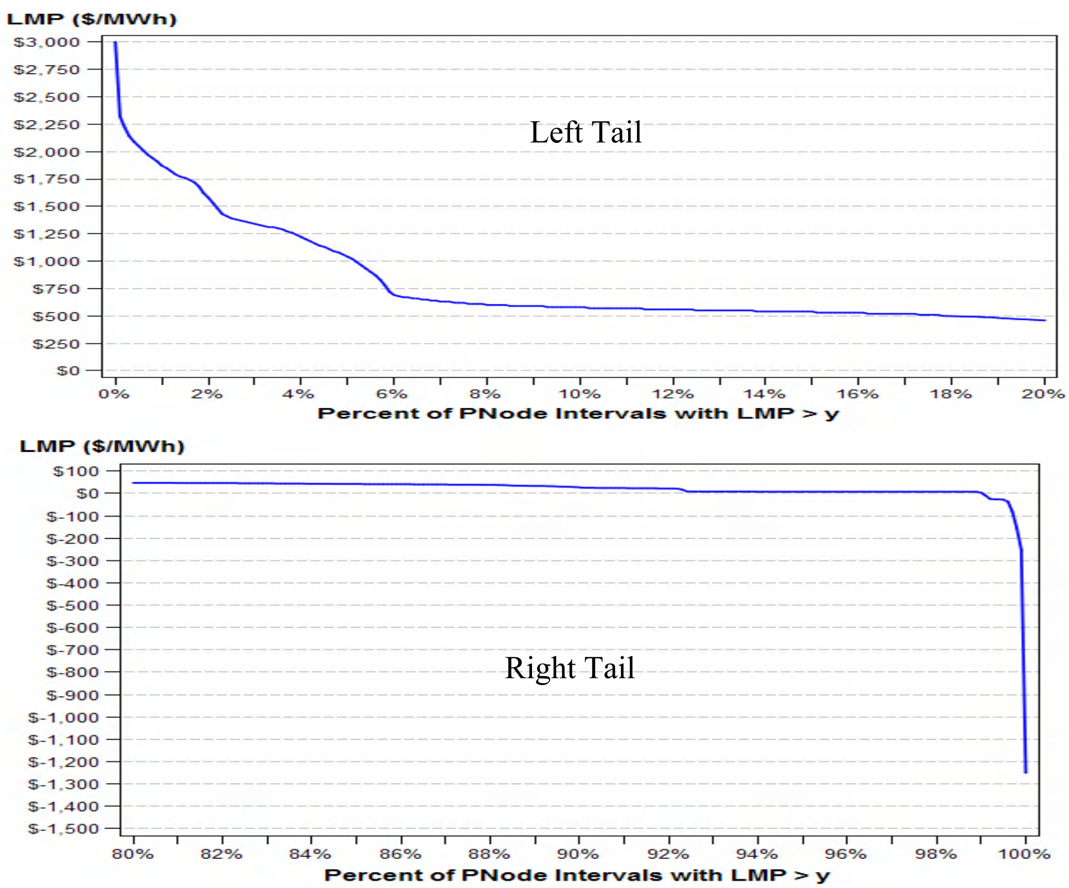
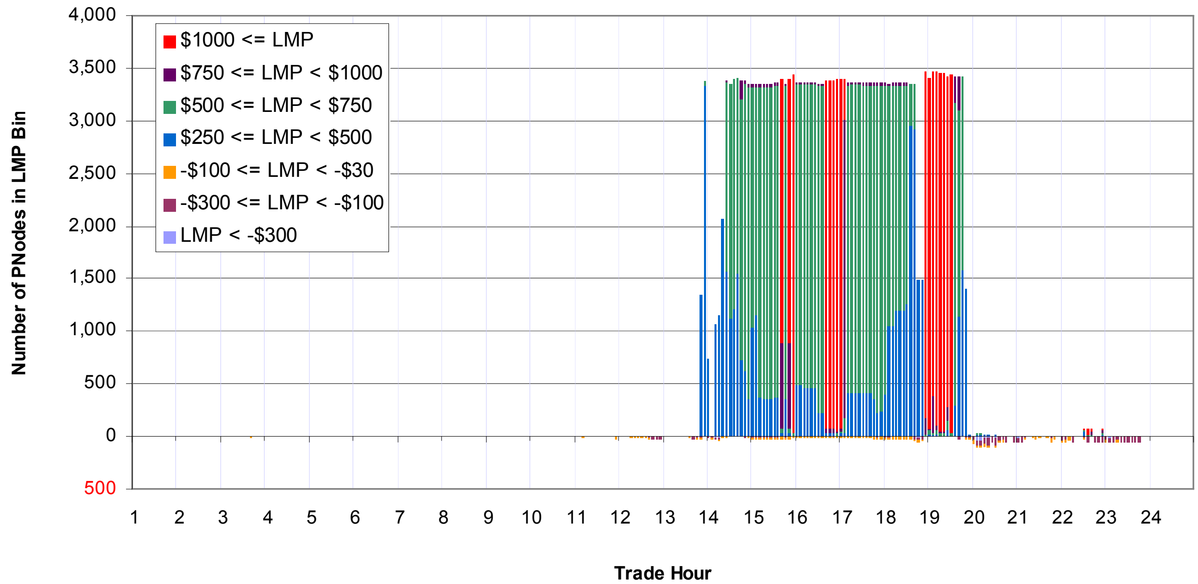


Figure 56 provides a count of the number of P-Nodes within specific price ranges for each interval of the day in RTD. Essentially all of the high RTD LMPs occurred during the peak hours. RTD LMPs in excess of $1,000/MWh occurred mostly in Hours 15, 16, and 19 and were fairly widespread.

Figure 56. RTD LMP Frequencies by Interval (December 12, 2008)



Comparison of Inter-tie Prices

This section reviews inter-tie prices in the structured simulation with a particular emphasis on a comparison of prices between the IFM and HASP markets. As noted in the overview, our analysis of September market simulation results found that prices for imports and exports on inter-ties with other control areas tended to be significantly higher in the HASP than in the IFM. We noted that if such significant and systematic price divergences for imports and exports persisted under MRTU, it could result in market inefficiencies and potential implicit virtual bidding where market participants submit IFM bids and schedules on the inter-ties with no intent or ability to deliver (or receive) and instead intend to buy or sell back their position in the HASP.

As noted in our analysis of September market simulation results, the quantity of demand clearing the IFM was consistently well below the total system load in the September simulations. This trend would tend to make HASP prices higher than IFM prices, simply because the additional demand clearing in the HASP would be met by the remaining (higher priced) portion of supply bids in the market simulation. In order to further assess the degree to which this persistent price divergence was due to load under-scheduling – rather than other factors related to the MRTU design or software – the scenarios that were run for the simulations for trade dates December 9, 11 and 12, 2008 were structured so that approximately 90 to 95 percent of load cleared the IFM. Meanwhile, the scenario for trade date December 10 was structured so that only approximately 85 percent of load cleared IFM, similar to the September simulation conditions.

The following sections review the inter-tie prices resulting from these scenarios for the Palo Verde, El Dorado, Mead, PACI (Malin), PDCI (Nob), and SMUD/WAPA tie points. As indicated below, the prices appear generally reflective of the scenarios modeled, with much better price convergence between the IFM and HASP.

December 9, 2008

As noted earlier in this report, the scenario run for December 9, 2008, resulted in approximately 95 percent of load being cleared in the IFM during peak hours. This was a much larger proportion of load cleared in the IFM than occurred in the September market simulations, when load was significantly under-scheduled in the IFM, and HASP inter-tie prices averaged as much as $100/MWh or more higher than IFM prices.

Figure 57 - Figure 62 show the Day Ahead (IFM) and HASP prices for December 9, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As evident in these figures, inter-tie prices show much better price convergence between the IFM and HASP than was observed in the September market simulation results. Price differences between the IFM and HASP for December 9 on individual tie points generally average only about $10/MWh, with some inter-ties exhibiting higher prices in the HASP than the IFM and other inter-ties exhibiting lower prices. This improved price convergence in the December 9 results is consistent with the higher proportion of load being cleared in the IFM. HASP inter-tie prices for December 9 that are lower than IFM prices (i.e., El Dorado, Mead) are likely attributable to constraints in the HASP increasing the congestion component of these inter-tie prices and consequently decreasing these tie point prices. With the exception of the Palo Verde and PACI inter-ties, the prices for the inter-ties shown in Figure 57 - Figure 62 follow the general pattern of the LAP prices.

On the Palo Verde inter-tie, import self-schedules appear to have been greater than the Palo Verde scheduling limit in the IFM on December 9. This appears to have resulted in self-schedules with the $30/MWh penalty bid price used for self-schedules in the IFM pricing run setting the price on Palo Verde. In the HASP, the total quantity of import self-schedules and bids on Palo Verde appears to have been greater than the scheduling limit, which appears to have resulted in the HASP price being set by marginal $10/MWh or $30/MWh import bids on Palo Verde.

A similar situation appears to have existed for the PACI tie point, where the price remained at $30/MWh in the HASP throughout the peak hours. Under actual market conditions, prices on these inter-ties would not be expected to diverge as much from the prices for other inter-ties, as market participants would be expected to respond to the low prices paid for imports at these inter-ties by either decreasing the quantity of imports offered at these inter-ties or increasing purchases of exports. Each of these responses would decrease the net quantity of imports, and thereby raise prices to be more aligned with prices on other tie points in the HASP and IFM. However, since participants do not actually have any economic incentives in the context of a market simulation, no such price responses appear to have occurred in market simulations.

Figure 57. Comparison of Palo Verde Prices (DA, HASP) – December 9, 2008

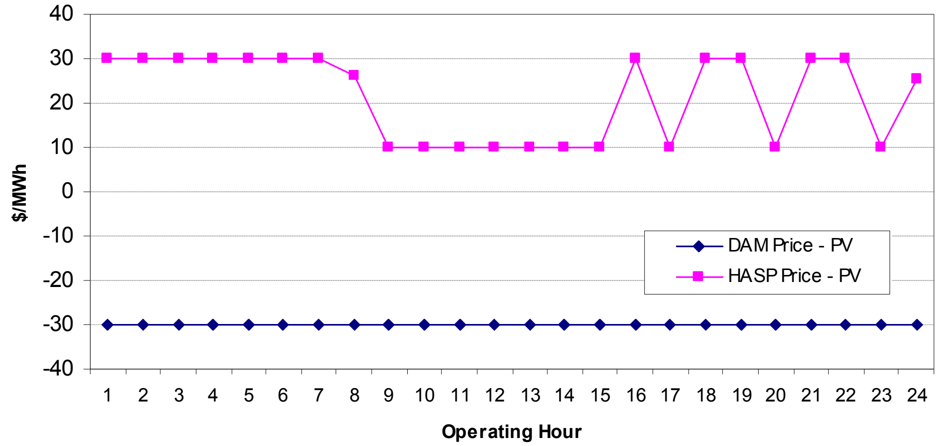


Figure 58. Comparison of El Dorado Prices (DA, HASP) – December 9, 2008

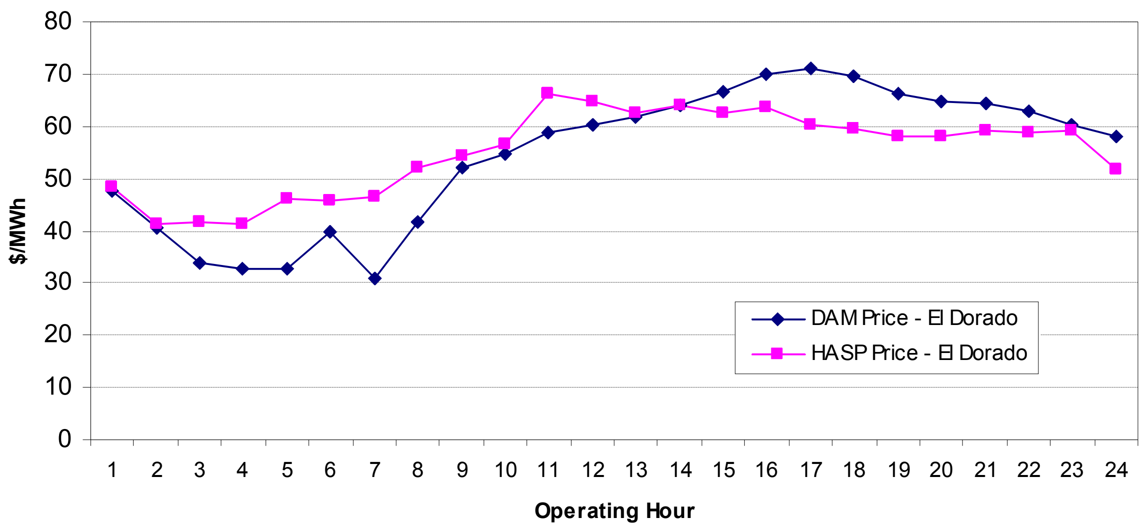


Figure 59. Comparison of Mead Prices (DA, HASP) – December 9, 2008

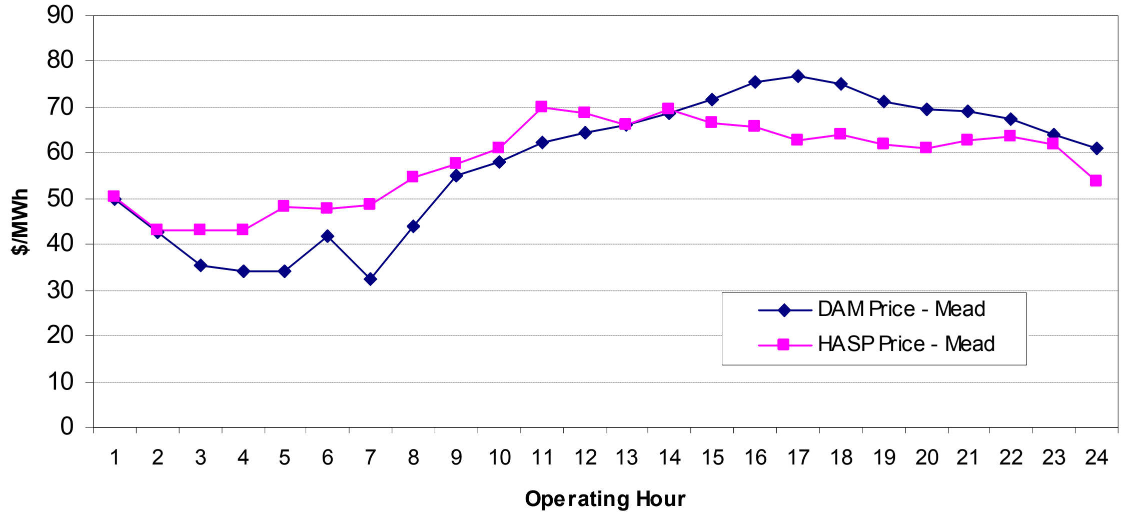


Figure 60. Comparison of PACI Prices (DA, HASP) – December 9, 2008

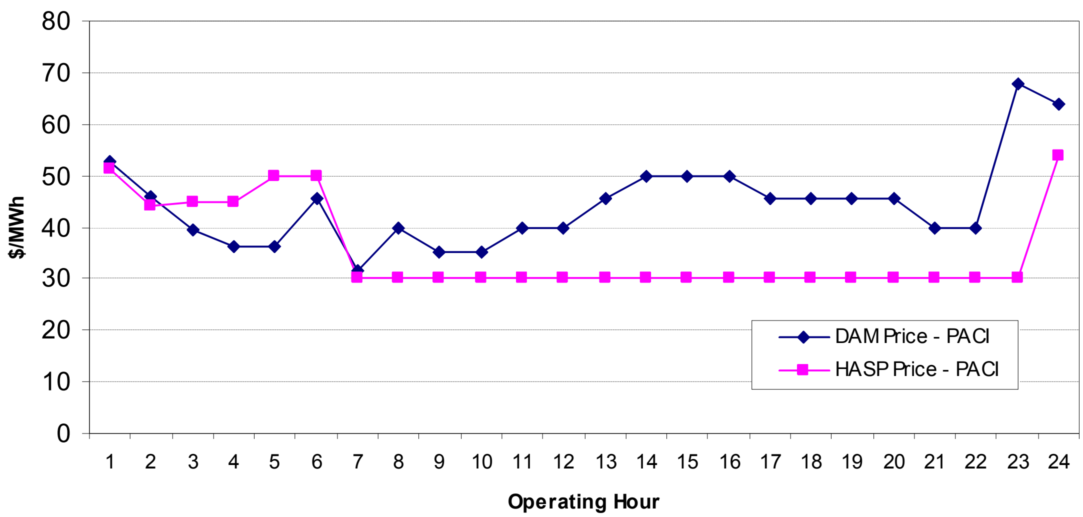


Figure 61. Comparison of PDCI (NOB) Prices (DA, HASP) – December 9, 2008

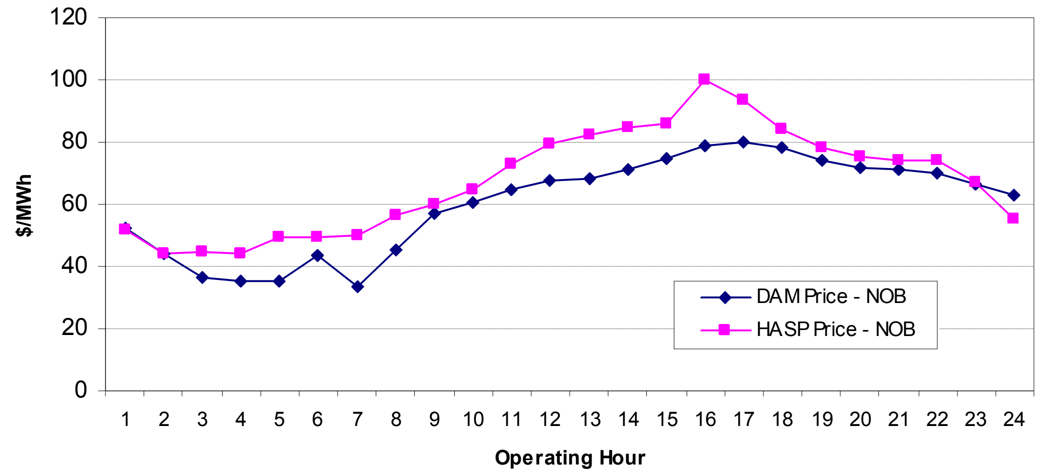
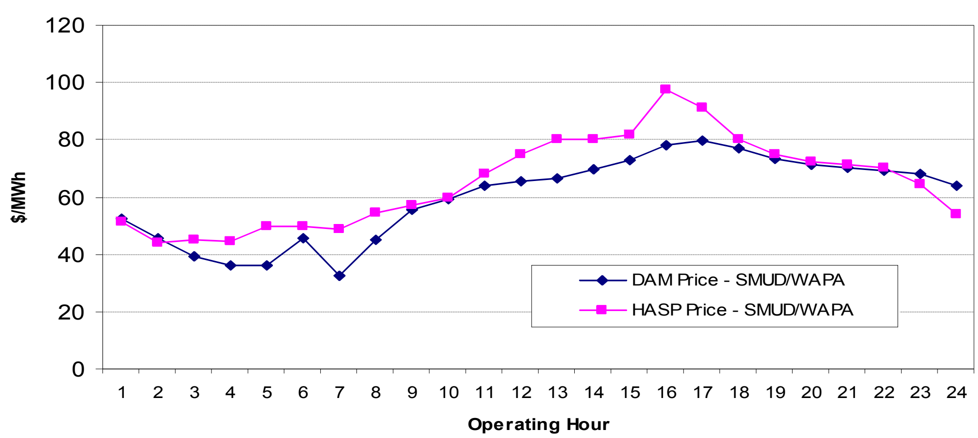


Figure 62. Comparison of SMUD/WAPA Prices (DA, HASP) – December 9, 2008



December 10, 2008

The scenario run for December 10, 2008, resulted in approximately 85 percent of load being cleared in the IFM during peak hours, as compared to the 95 percent of load cleared in IFM on December 9. Because relatively more incremental supply would need to be cleared in HASP under the scenario run for December 10, the HASP inter-tie prices would be expected to increase relative to the IFM prices and be more similar to the prices in the September market simulations, when a similar level of load under-scheduling occurred. In addition, as described earlier in this report, it appears that significantly less real-time energy bids were provided to the market simulation for December 10-12 compared to December 9, which would be expected to further increase HASP prices compared to IFM prices for these days.

Figure 63 - Figure 68 below show the Day Ahead and HASP prices for December 10, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As

shown by these figures, the prices on these inter-ties are for the most part consistent with the under-scheduling scenario run for December 10 and decrease in supply bids submitted in the HASP during this scenario compared to the December 9 scenario. While HASP prices were at most approximately $10/MWh more than the corresponding IFM prices for December 9, HASP prices increased for December 10 to a range of about $20 to $40/MWh greater than IFM prices, with much greater differences existing during HE 14-18. HASP prices were approximately $400/MWh greater than IFM prices on the PDCI and SMUD/WAPA inter-ties during these hours, which were reflective of the price spikes seen in the LAPs during these hours, as described earlier in this report.

Meanwhile, prices on the Palo Verde and PACI inter-ties for December 10 differed from the general pattern described above. Similar to the situation that existed for Palo Verde on December 9, the prices for Palo Verde appear for the most part to be set by import self-schedules that exceed the scheduling limit. Also, as occurred during the December 9 scenario, the HASP prices for the PACI inter-tie for December 10 appear for most hours to be set by import self-schedules that exceeded the scheduling limit. Again, since the amount of import schedules on Palo Verde and PACI and the resulting prices do not appear to reflect economic incentives and actual market dynamics, these simulation results are probably not reflective of what would be expected under actual market conditions.

Figure 63. Comparison of Palo Verde Prices (DA, HASP) – December 10, 2008

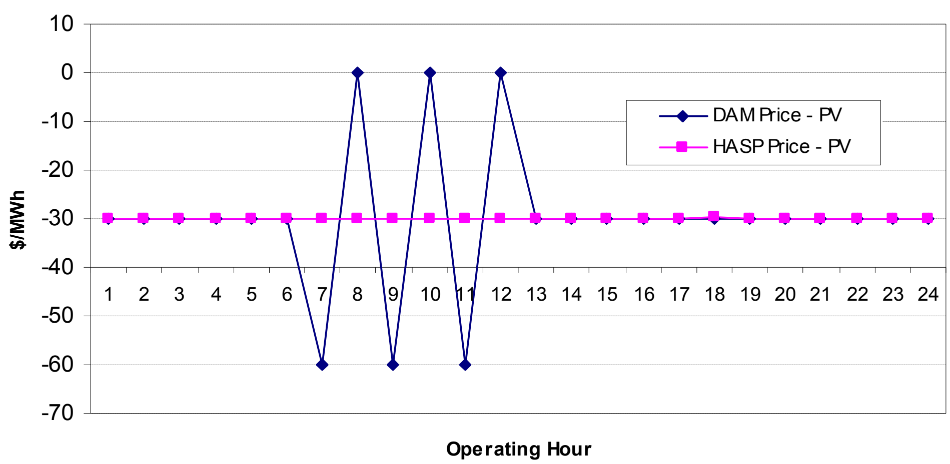


Figure 64. Comparison of El Dorado Prices (DA, HASP) – December 10, 2008

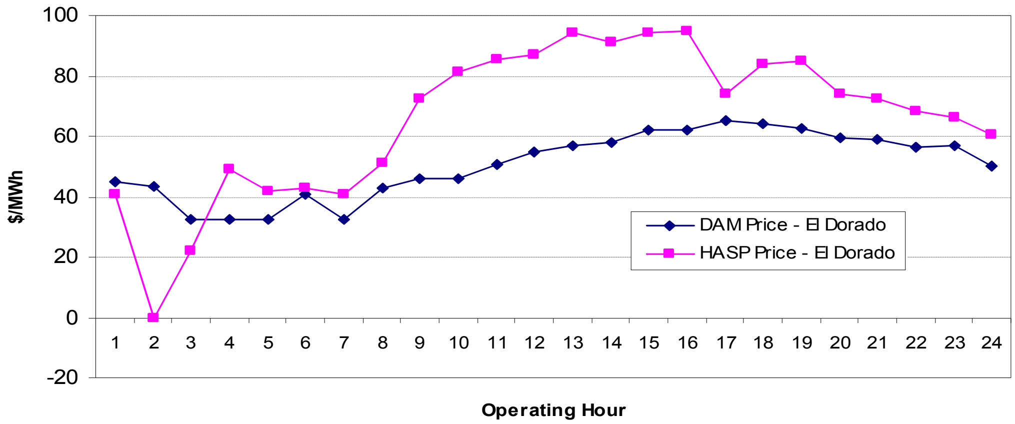


Figure 65. Comparison of Mead Prices (DA, HASP) – December 10, 2008

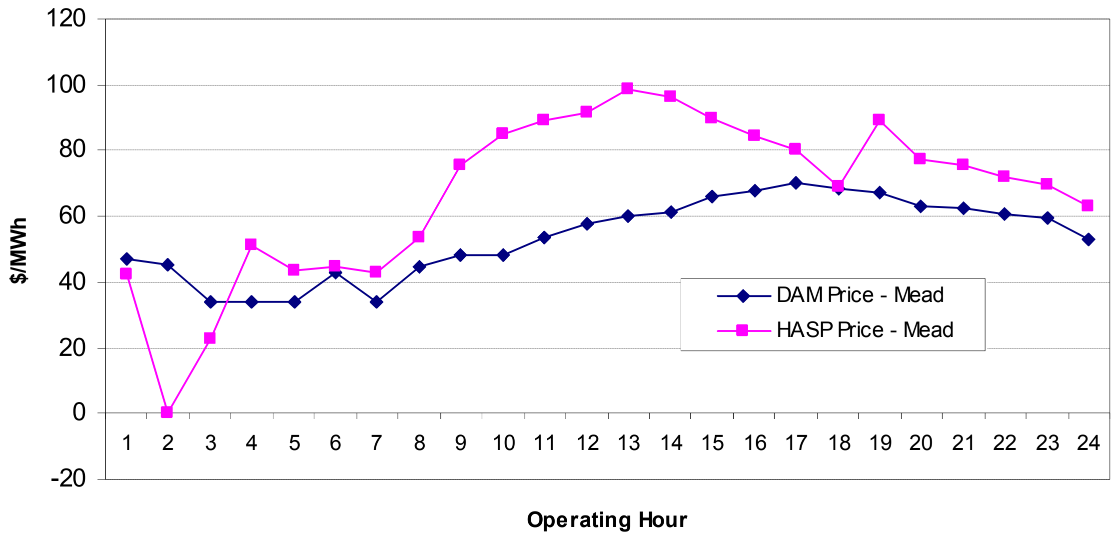


Figure 66. Comparison of PACI Prices (DA, HASP) – December 10, 2008

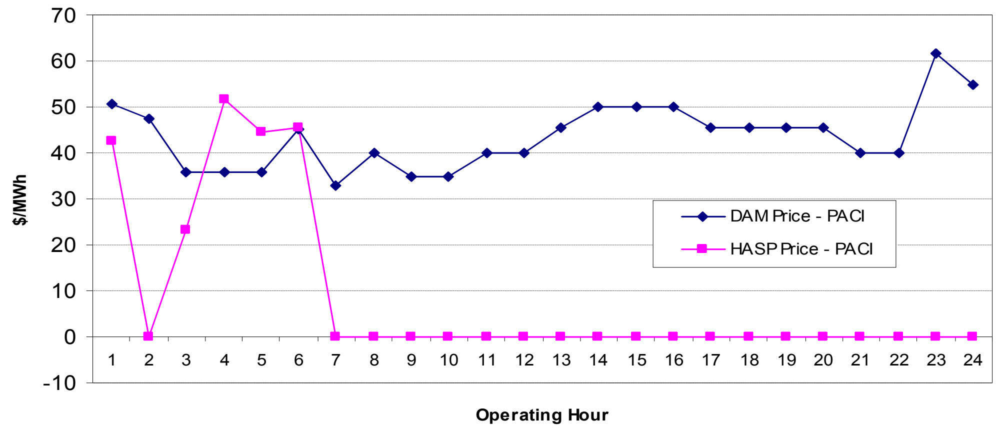


Figure 67. Comparison of PDCI (NOB) Prices (DA, HASP) – December 10, 2008

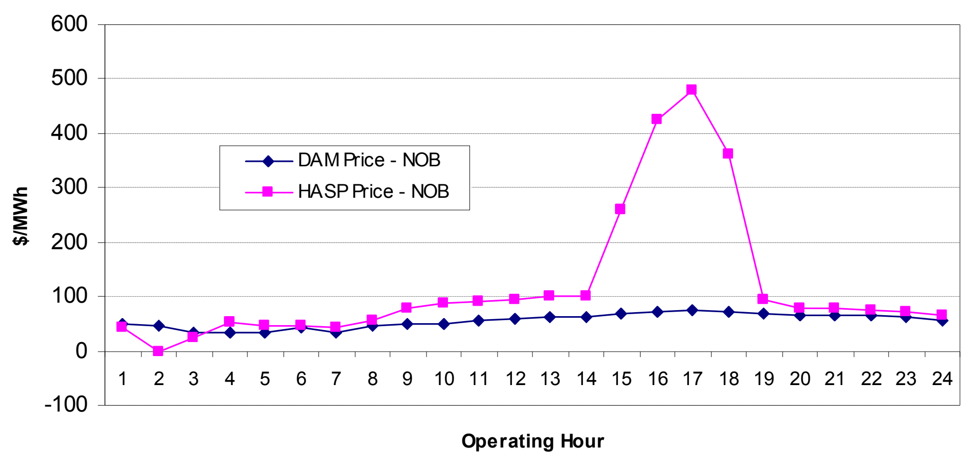
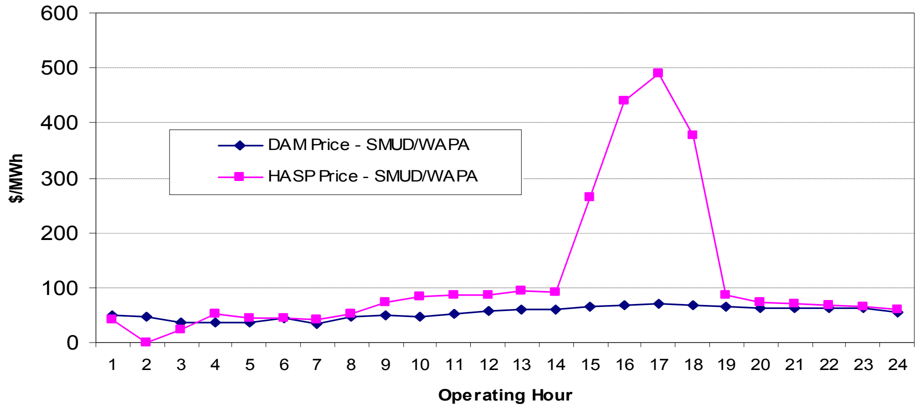


Figure 68. Comparison of SMUD/WAPA Prices (DA, HASP) – December 10, 2008



December 11, 2008

The scenario run for December 11, 2008, incorporated a significant level of potential economic withholding through relatively high priced generation bids in load pockets, with the amount of load cleared in IFM similar to December 9. Figure 69 - Figure 74 below show the Day Ahead and HASP prices for December 11, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As shown by these figures, prices are generally similar to the prices for December 9, except that prices are somewhat higher in the HASP. These higher prices in the HASP are reflective of the price spikes seen in the LAPs during peak hours on December 10, as described earlier in this report. The prices in the IFM for Palo Verde and the El Dorado tie points differ from this general pattern. The $-30/MWh IFM prices for Palo Verde that persisted for most of the day are, similar to December 9 and December 10, likely attributable to import self-schedules that exceeded the import limit. The very low IFM prices for both Palo Verde and El Dorado for HE 14-19 were potentially due to the interaction of self-schedules and/or bids between inter-ties as these inter-ties are modeled as an external loop.

Figure 69. Comparison of Palo Verde Prices (DA, HASP) – December 11, 2008

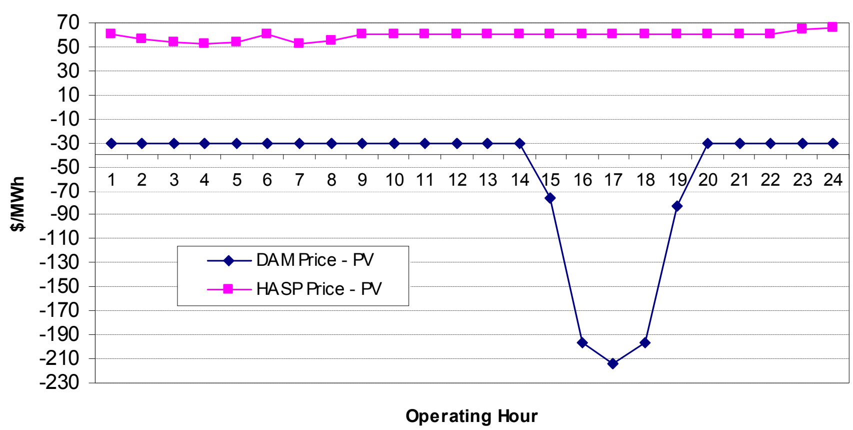


Figure 70. Comparison of El Dorado Prices (DA, HASP) – December 11, 2008

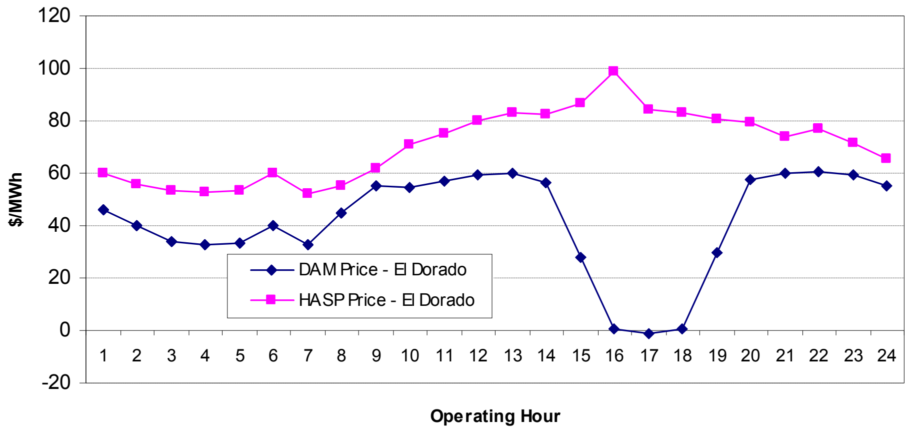


Figure 71. Comparison of Mead Prices (DA, HASP) – December 11, 2008

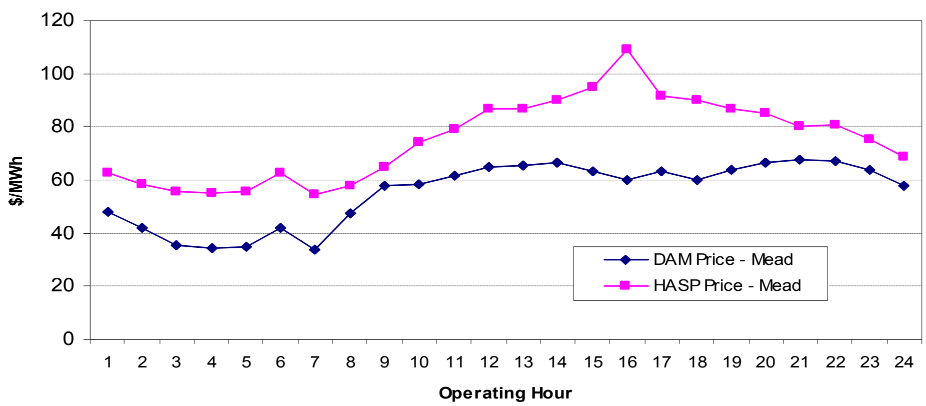


Figure 72. Comparison of PACI Prices (DA, HASP) – December 11, 2008

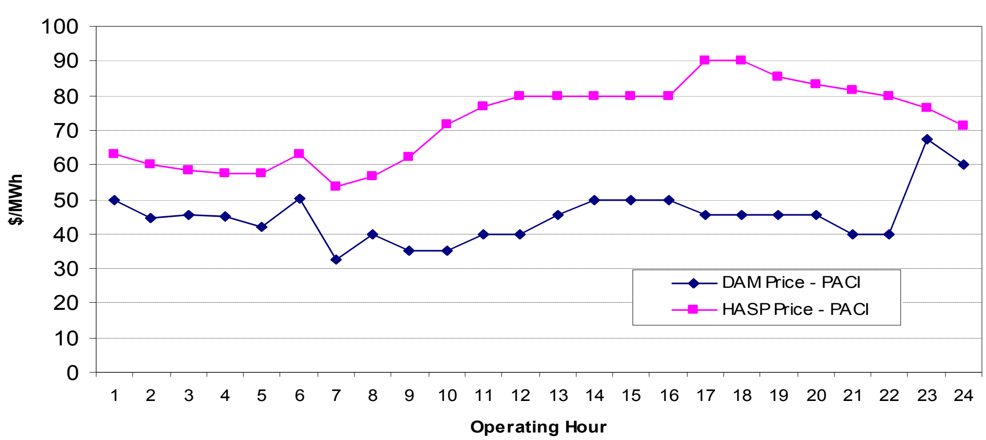


Figure 73. Comparison of PDCI (NOB) Prices (DA, HASP) – December 11, 2008

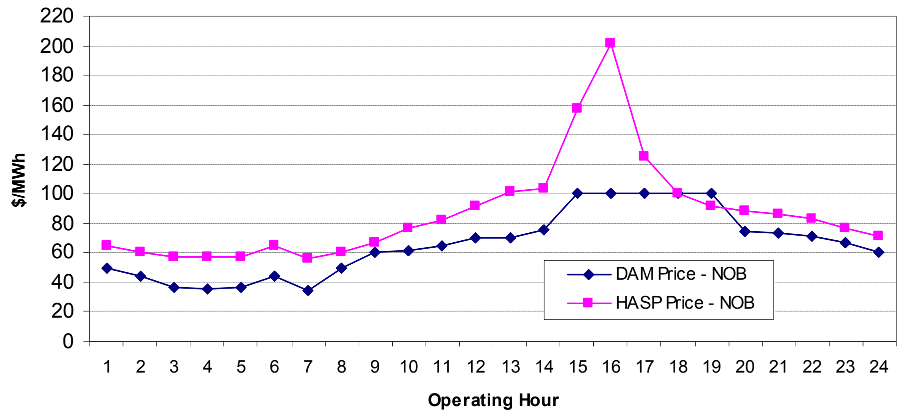
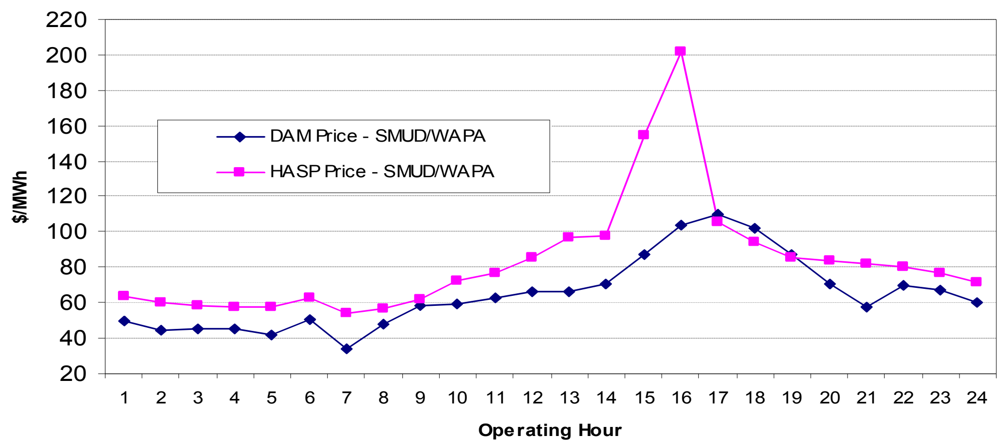


Figure 74. Comparison of SMUD/WAPA Prices (DA, HASP) – December 11, 2008



December 12, 2008

The scenario run for December 12, 2008, consisted of the real-time load forecast being 5 percent higher than the day-ahead load forecast, with the amount of load cleared in IFM similar to December 10. Figure 75 - Figure 80 below show the Day Ahead and HASP prices for December 12, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As shown by the figures, the El Dorado, Mead, PDCI, and SMUD/WAPA inter-ties had price spikes of varying degrees in the HASP, with some very high prices occurring under this scenario. These price spikes were consistent with very high LAP prices in the HASP in these same hours. Similar to other days, Palo Verde exhibits negative prices in the IFM and HASP, and PACI had zero or negative prices in the HASP.

Figure 75. Comparison of Palo Verde Prices (DA, HASP) – December 12, 2008

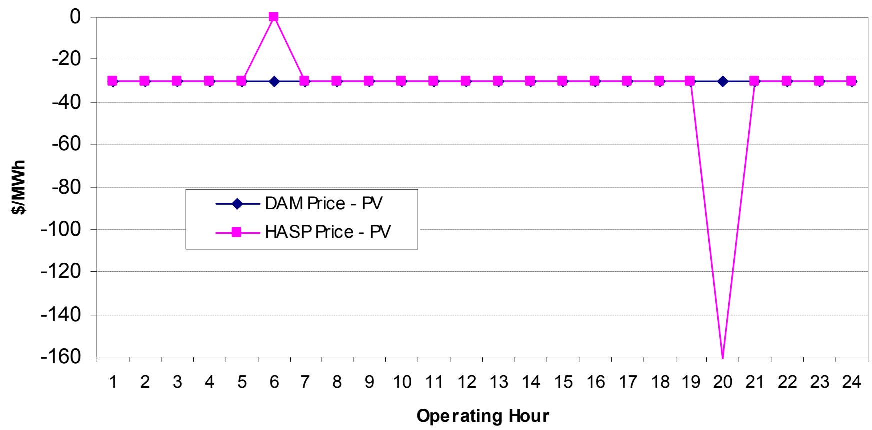


Figure 76. Comparison of El Dorado Prices (DA, HASP) – December 12, 2008

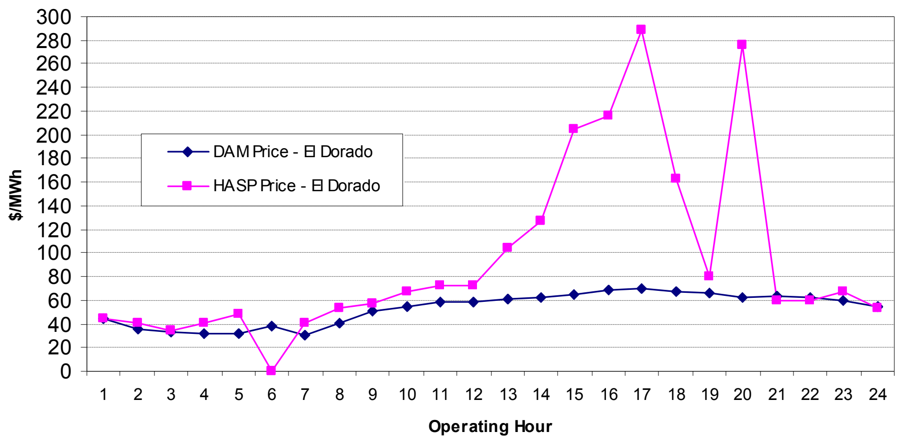


Figure 77. Comparison of Mead Prices (DA, HASP) – December 12, 2008

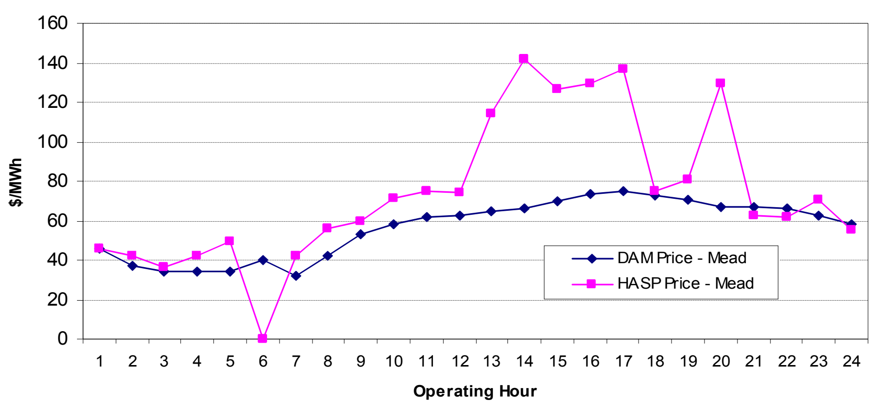


Figure 78. Comparison of PACI Prices (DA, HASP) – December 12, 2008

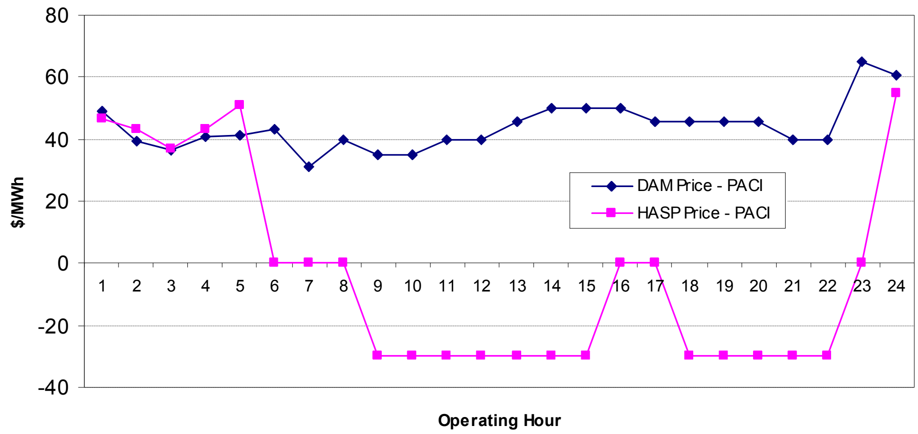


Figure 79. Comparison of PDCI (NOB) Prices (DA, HASP) – December 12, 2008

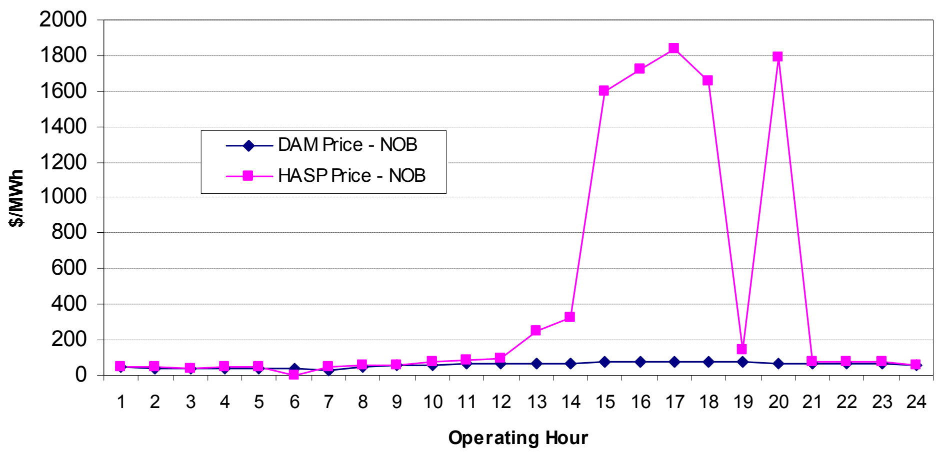
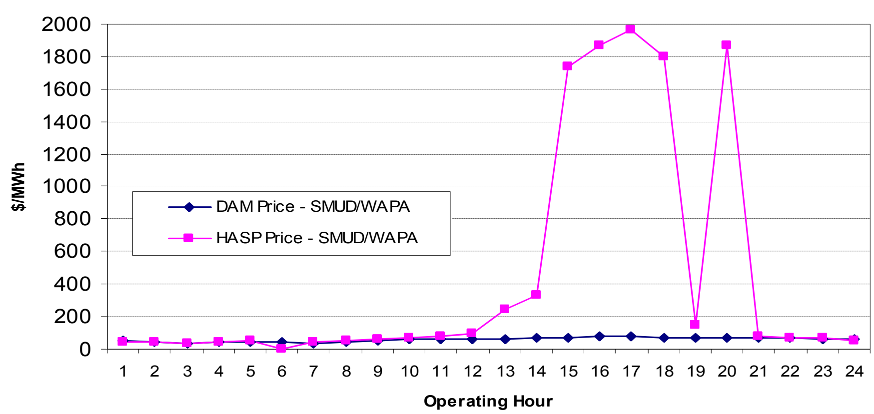


Figure 80. Comparison of SMUD/WAPA Prices (DA, HASP) – December 12, 2008



IV. Local Market Power Mitigation

Overview

This section summarizes DMM's review of the performance of the Local Market Power Mitigation (LMPM) provisions of the MRTU market design and software. As noted in our October Report, the MRTU market design relies upon a variety of LMPM provisions that are designed to work together to effectively mitigate local market power. These include:

- Identification of uncompetitive constraints through the Competitive Path Assessment (CPA), and incorporation of these results into the MRTU day ahead and real time market models.
- Establishment of Default Energy Bids (DEBs) reflective of competitive bid prices, to be used as the basis for limiting bids for resources dispatched to meet uncompetitive constraints.

- Successful execution of local market power mitigation runs and bid mitigation procedures prior to the day ahead and real time markets.

DMM has been reviewing market simulation results to ensure that each of these LMPM components is correctly implemented, and has designed metrics to monitor the effectiveness of each of these LMPM provisions after MRTU go-live.

In our October Report, DMM indicated that the LMPM features of the MRTU software were mechanically functioning as intended and effectively mitigating local market power, with one major exception:

- **Skipped or failed LMPM procedures** - During the September period covered in the October Report, DMM found that LMPM procedures failed to run or were skipped prior to the hourly HASP/RTM in as much as 5 percent of hours. Such failures are generally caused when the software fails to reach a solution in the required amount of time. Review of market simulation logs for December indicates that such problems may continue to be occurring in about 5 percent of hours. Thus, we are again recommending that the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. In addition, DMM has recommended that the CAISO establish pricing provisions that may be applied in cases where the LMPM procedures are not completed in the RTM in actual market operation.

In our October Report, DMM also indicated that we planned to complete further review of LMPM performance, including additional analysis in four areas:

- **LMPM effectiveness with nomogram constraints identified as "competitive" enforced in the competitive run of the market power mitigation procedures.** As noted in our October Report, no competitive nomograms were being enforced in the competitive run of the LMPM procedures at that time. This created the potential that LMPM procedures could be less effective once these nomogram constraints began to get enforced in the Competitive Constraints (CC) run of the market power mitigation procedures, rather than only being added in the All Constraints (AC) run. Since November, however, these competitive nomograms have been enforced in the Competitive Constraints (CC) run of the LMPM procedures. Thus, more recent market simulation results – including all of the structured market simulations for the December 9-12 period covered in this report – use the same designations of competitive vs. non-competitive constraints that would be used upon MRTU implementation under results of DMM's most recent CPA studies.[17]

- **Additional stress testing of the LMPM procedures by running special bidding scenarios.** The structured market simulation scenario for the December 11 trade date was specifically designed to test LMPM procedures under relatively high levels of economic withholding within some transmission constrained local areas. However, as discussed in this report, this single scenario primarily provides a test of LMPM effectiveness only within the San Diego area in the IFM. Thus, DMM will continue to perform additional off-line testing of LMPM effectiveness in other areas and in the RTM.
- **Default Energy Bids (DEBs).** As noted in our October Report, DMM will continue to review and monitor default energy bids (DEBs), including DEBs developed under the consultative DEB option. To date, very few market participants have engaged in discussion with the entity under contract by the CAISO to establish any special negotiated DEBs (Potomac Economics). However, DMM will continue to review and monitor DEBs established pursuant to provisions in the MRTU Tariff and Business Practice Manual (BPM) for Market Instruments.
- **Unit Operating Characteristics.** DMM has continued to review and monitor other resource characteristics that may be submitted by participants to the CAISO Master File and/or as part of market inputs, such as:
  - Ramp rates;[18]
  - Start-up and minimum load data; and
  - Requests for treatment as a use-limited resource.

  Our review of units requesting designation as use-limited resources indicates that over 1,000 MW of combustion turbine capacity under Resource Adequacy (RA) contracts have been designated as use-limited resources due to air permitting constraints (e.g., limiting units to no more than 876 operating hours and a limited number of start-ups per year). While these units are subject to a must-offer obligation if they are under an RA contract, there is no specific requirement for the amount of energy that must be scheduled or bid into the CAISO market during any specific hour. Although these units are required to submit a use plan for review and approval by the CAISO, our review of use plans indicates that such plans typically specify only a target number of operating hours per month, and do not specify whether or how a unit would be actually scheduled or offered in the CAISO markets during critical peak hours. Since many of these units are within transmission constrained areas, the portion of

[17] A list of CPA results was provided in our October Report. DMM plans on formally releasing its next CPA Report in February 2009, or at least 30 days prior to the scheduled date of MRTU implementation. Based on current data, DMM does not expect any revisions to the results in our October Report, which already reflected information on contractual ownership and control of resources during 2009 collected from market participants.

[18] As summarized in our October Report, operational ramp rates submitted for some units – particularly combined cycle units – were significantly lower than maximum ramp rates listed in the CAISO Master File. However, this was consistent with indications by some generators that ramp rates were being used to reflect operational limits of combined cycle units not captured in MRTU modeling. In addition, at that time, the lower ramp rates being submitted for some combined cycle units were not found to be a significant factor in IFM or RTM price spikes.

this capacity that is actually scheduled or offered in the CAISO markets during critical peak hours could have an impact on LMPM effectiveness. Thus, we recommend that the CAISO monitor the actual availability of these resources, and, if necessary, seek to establish more specific scheduling and bidding requirements for these units through use plans and/or other market design enhancements.

The remainder of this section summarizes our review of the performance of LMPM provisions in the structured market simulation scenarios tested during the December 9-12 trade dates. As indicated below, our review of these simulation results indicates that the LMPM features of the MRTU software are mechanically functioning as intended and effectively mitigating bids with one notable exception:

- **High MIP Gap.** During the December 11 market scenario designed specifically to test the LMPM features of the MRTU software, extremely high LMPs occurred within the San Diego area during several hours of the IFM when the software did not reach the target level of optimality as measured by the "MIP Gap".[19] However, by running this scenario offline for a greater number of iterations, DMM and Market Operations confirmed that as the MIP Gap is lowered, one additional unit would be committed within the San Diego area, and LMPs would fall within competitive levels reflecting the DEBs used to mitigate bids when LMPM provisions are triggered.[20]

This exception underscores the importance of providing sufficient time for the IFM to find an optimal solution – even if that means significantly extending the close of the Day Ahead Market.

Bid Inputs for Local Market Power Scenario (December 11)

The December 11 Market Simulation scenarios was specifically designed to test the local market power mitigation features of the MRTU software in IFM and RTM. For the local market power scenario, bids for the base case scenario performed on December 9 were modified to reflect a scenario where a significant portion of gas-fired capacity owned or contractually controlled by non-load-serving entities is economically withheld by being bid at a price of $400/MW. The capacity economically withheld in this scenario was all located within the CAISO's four largest Local Capacity Areas (LCAs):

- Greater Bay Area (in PG&E LAP)
- Big Creek Ventura (in SCE LAP)
- Los Angeles Basin (in SCE LAP)
- San Diego (in SDG&E LAP)

Figure 81 provides a comparison of energy bids for all resources within these LCAs used in the IFM in the base case scenario (December 9) and the market power scenario (December 11).

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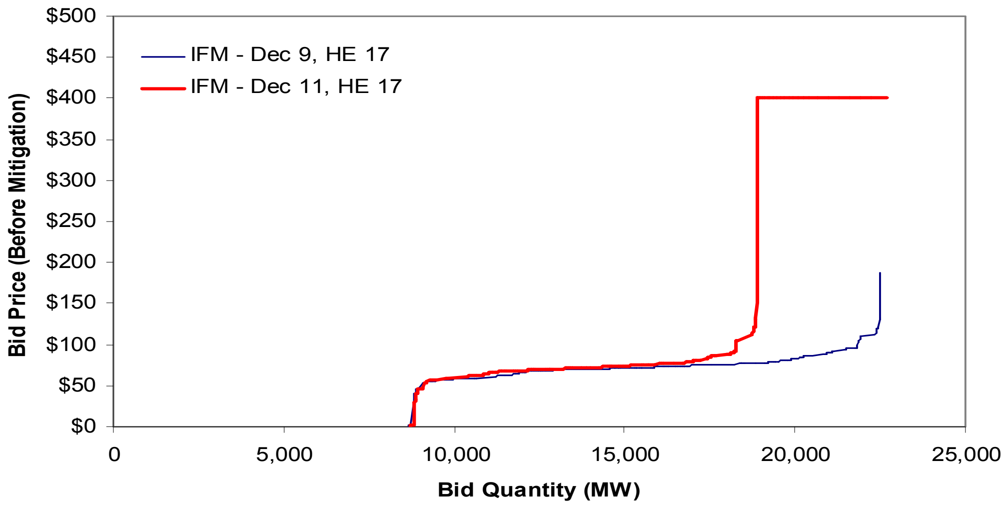
[19] For a discussion of the "MIP Gap" see *Final Report: Analysis Track Testing of CAISO MRTU Pricing and Dispatch*, October 20, 2008, prepared by Scott Harvey et. al.,(LECG) http://www.caiso.com/2067/2067769c1c5a0.pdf

[20] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, December 23, 2008, slide 5-7, presentation Dec 23, 2008 http://www.caiso.com/20a6/20a67f452b390.pdf

Table 13 provides a breakdown of the capacity economically withheld in the IFM during the December 11 scenario by LCA.[21]

In the December 11 market power scenario, IFM bids were established directly by the CAISO, with all bids in the RTM being submitted by market participants. In some cases, however, RTM bids submitted by participants were not the same as the IFM bids submitted by the CAISO in the IFM. Figure 82 provides a comparison of energy bids for all resources within these LCAs used in the IFM in the base case scenario (December 9) and the market power scenario (December 11). As shown in Figure 82, a significantly greater amount of capacity was self-scheduled in the RTM in the December 11 market simulation than in the IFM for that operating day, while less capacity was bid at the $400/MW level. This change in RTM bids contributed to the lack of mitigation that occurred in the RTM under the December 11 scenario.

Figure 81. IFM Bids within Major Local Capacity Areas (December 9 and 11 Scenarios)

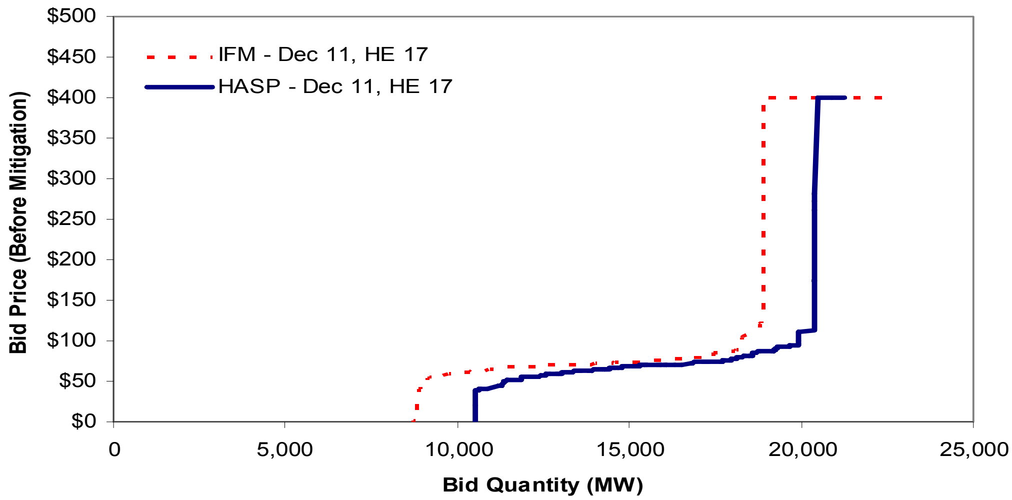


[21] As shown in Table 13, the portion of capacity economically withheld was extremely high in the San Diego LCA (56 percent), and relatively high in the Big Creek Ventura LCA (31 percent), but was relatively low in the Bay Area LCA (10 percent) and LA Basin (4 percent). The level of economic withholding within each LCA was initially designed to assume that about half of the capacity under the control of non-LSEs (i.e., excluding any capacity under tolling agreements or RMR contracts) was economically withheld. After initial market simulation results from initial tests in November indicated that very minimal mitigation would occur under these initial assumptions, the level of economic withholding in the December 11 scenario was increased to levels that would trigger a more significant level of mitigation in the San Diego LCA.

Table 13. IFM Bids within Major Local Capacity Areas (December 11 Scenario)

Area (LCA)	Self Scheduled and Minimum Load Energy (MW)	Capacity Bid at Base Case Price (Cost+20%)	Capacity Economically Withheld (MW)	Total Capacity Bid in IFM (MW)	Percent of Capacity Economically Withheld
LA Basin	4,398	5,266	364	10,028	4%
Bay Area	2,285	3,013	605	5,904	10%
Big Creek/Ventura	1,062	1,538	1,179	3,779	31%
San Diego	961	345	1,664	2,970	56%
Total	8,706	10,162	3,813	22,681	17%

Figure 82. IFM and HASP Bids within Major Local Capacity Areas (December 11 Scenario)



Market Simulation Results for IFM

Table 14 summarizes the hours in which LMPM procedures triggered bid mitigation in the IFM during the December 9-12 structured market simulation tests. As shown in Table 14:

- LMPM was triggered in the San Diego LCA during at least nine peak hours on all days. A more detailed discussion of mitigation in this LCA is provided later in this section.
- Minimal bid mitigation was triggered in all other LCAs, even under the December 11 bidding scenario.

Table 14. Occurrence of Local Market Power Mitigation in IFM

LCA	Structured Simulation Scenario			
	Dec 9 Base Case (Gas units bid at cost + 20%)	Dec 10 Load Underscheduling	Dec 11 Local Market Power	Dec 12 High Load/ Forecast Error (+5%)
Bay Area			HE 3-4	HE 16-17 and 23
Big Creek/Ventura		HE 8	HE 8-9	
LA Basin				
San Diego	HE 11-23	HE 13-22	HE 10-23	HE 7-22

Appendix A provides a detailed hourly summary of the number of units subject to mitigation in the IFM within each LCA on these four days, along with the total capacity of these units and other statistics relating to LMPM. Figure 83 lists the specific data included in the hourly summaries.

The following sections include examples of these hourly summaries – along with graphical examples of bid mitigation for specific hours in which LMPM bid mitigation was triggered in the San Diego LCA.

Figure 83. Description of Data in Table 15

Total Bids (MW). Total capacity bid into IFM in each hour by all resources within an LCA. Includes self-scheduled energy and non-gas units.

Dispatched MW - CC Run. Total capacity (MW) within an LCA dispatched in the Competitive Constraints (CC) run of the pre-market local market power mitigation procedures. CC run based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW - AC Run. Total capacity (MW) within an LCA dispatched in the All Constraints (AC) run of the pre-market local market power mitigation procedures. AC run is based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW – IFM. Total capacity (MW) within an LCA dispatched in the IFM, after any bid mitigation occurring from the CC and AC runs.

Mitigation – Units. Number of units within LCA subject to potential bid mitigation. A unit is subject to bid mitigation if dispatched in AC run at a higher level than in CC run.

Mitigation – MW. Total capacity of the units within an LCA subject to bid mitigation, i.e., the capacity greater than the unit's dispatch in the CC run up to the unit's maximum bid level (typically PMax). It should be noted that whether these units' market bids for this portion of their capacity was actually mitigated (i.e., lowered) depends on two factors. First, the units highest accepted bid in the CC run is a floor below which bid prices for additional capacity above this level cannot be lower. Second, the market bids are only lowered if they are greater than the unit's DEB for that portion of their capacity.

AC Run – Max Bid. Maximum bid within an LCA cleared in AC run (based on market bids prior to any mitigation), which can provide an indication of the potential impact of mitigation when compared to maximum bid dispatched in the IFM (after mitigation). However, maximum bid in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative bid prices representing negative bids placed on self-schedules and energy clearing AC run are omitted.

AC Run – Max LMP. Maximum LMP within an LCA cleared in AC run (based on market bids prior to any mitigation), which can provide an indication of the potential impact of mitigation when compared to maximum LMP in the (after mitigation). However, maximum LMP in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative LMPs typically reflect negative bids placed on self-schedules and capacity clearing AC run.

IFM – Max Bid. Maximum bid within an LCA cleared in IFM (after any mitigation). Can provide indication of whether high LMPs within LCA are set by resources within an LCA or system conditions.

IFM – Max LMP. Maximum LMP within an LCA in IFM.

Table 15. Summary of IFM and LMPM Results: San Diego LCA

December 11, 2008 Market Simulation (With High MIP Gap of 12%)

Hour	Total Bids (MW)	Dispatched MW			Mitigation		AC Run		IFM	
		CCR	ACR	IFM	Units	MW	Max. Bid	Max. LMP	Max. Bid	Max. LMP
1	2,920	506	506	498				-$29	$31	$49
2	2,919	497	497	497				-$29	$31	$43
3	2,919	497	497	497				$39	$31	$36
4	2,919	497	497	497				$39	$31	$35
5	2,919	497	497	497				-$29	$31	$36
6	2,954	532	532	512				$44	$31	$43
7	2,969	547	547	527				$35	$31	$35
8	2,969	555	555	527				$49	$31	$49
9	2,969	593	593	535				$60	$57	$60
10	2,969	664	727	633	3	171	$92	$71	$68	$64
11	2,971	766	885	717	4	186	$92	$78	$70	$70
12	2,971	803	972	797	6	174	$92	$94	$73	$82
13	**2,971**	**848**	**1,055**	**871**	**5**	**326**	**$92**	**$93**	**$73**	**$84**
14	2,971	865	1,108	912	3	309	$92	$96	$92	$120
15	2,970	998	1,243	918	2	297	$89	$90	$119	$317
16	2,970	1,089	1,372	1,031	2	297	$94	$95	$400	$513
17	**2,970**	**1,096**	**1,427**	**1,110**	**6**	**407**	**$400**	**$457**	**$400**	**$554**
18	2,970	1,043	1,285	1,041	2	297	$89	$90	$400	$513
19	2,970	983	1,230	918	2	297	$89	$90	$119	$313
20	2,970	864	1,103	911	3	309	$92	$93	$92	$108
21	2,970	847	1,063	891	5	326	$92	$93	$85	$90
22	2,970	802	981	870	5	371	$92	$86	$73	$86
23	2,970	745	804	760	3	171	$92	$73	$68	$69
24	2,955	589	589	626				-$29	$57	$60

San Diego – December 11, Hour Ending 13

As shown in Table 15, during Hour Ending 13 of the December 11 local market power scenario:

- A total of 848 MW was dispatched from resources within the San Diego LCA during the initial CC run of the pre-IFM LMPM procedure.
- During the AC run of the pre-IFM LMPM procedure, a total of 1,055 MW was dispatched, triggering LMPM bid mitigation procedures.
- During the AC run, five units were dispatched above the amount of these units' dispatch level in the CC run. As a result, all remaining capacity from these units above the CC dispatch level (326 MW) was subject to bid mitigation prior to the actual IFM market run.[22]
- During the AC run, the highest market bid dispatched (prior to mitigation) equaled $92, with the highest LMP within the LCA equaling $93.
- In the IFM, a total of 871 MW from capacity within the San Diego LCA was dispatched. The highest market bid dispatched (after mitigation) equaled $73, with the highest LMP within the LCA equaling $84.[23]

Figure 84 provides a graphical illustration of LMPM bid mitigation and IFM results for this hour. As indicated in the legend of this figure:

- The yellow line represents the combined bid curves of all bids submitted in the IFM by all resources in the San Diego LCA during this hour (prior to any bid mitigation). This bid curve includes all the ~2,900 MW of resources in the LCA, including longer start units that may not be committed in the IFM. The zero-price (flat, leftmost) portion of this bid curve represents capacity of any self-scheduled units, as well as the minimum load energy of any non-self scheduled resources.
- The light blue line represents the combined bid curves of all resources dispatched in the AC run of the pre-IFM LMPM procedures (<u>prior</u> to any bid mitigation). This bid curve represents less capacity than the yellow line since it excludes any resources not committed in the AC run. Under the LMPM market design, only bids from resources clearing the AC run are included in the IFM market run.
- The red line represents the combined bid curves of all resources dispatched in the AC run of the pre-IFM LMPM procedures <u>after</u> any bid mitigation. As noted above, during this hour five units (with combined bid quantity above their CC dispatch level of 326 MW) were subject to bid mitigation. Thus the difference in the light blue and red lines represents the effect of bid mitigation on the overall bid curves used in the IFM.

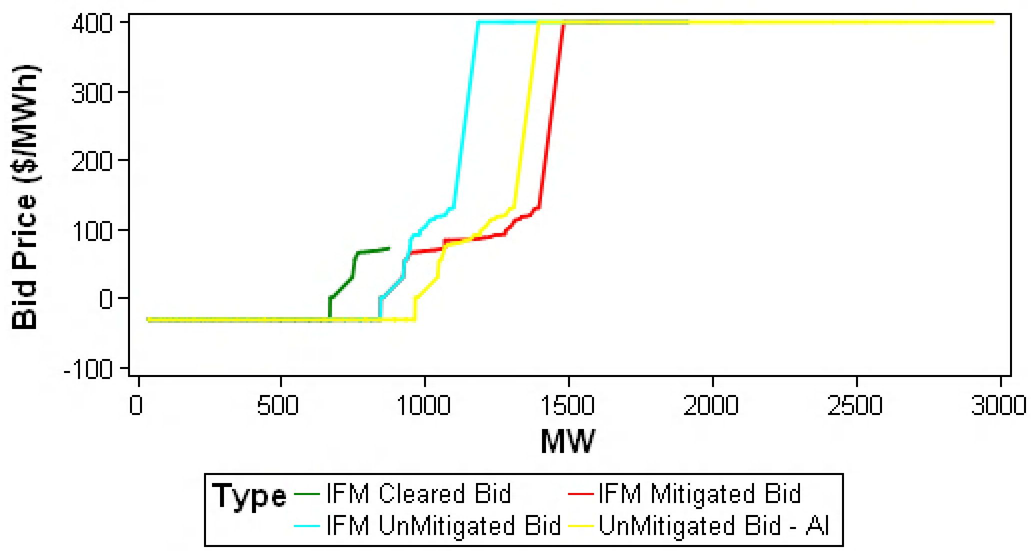
[22] For units with a dispatch in the CC run, their highest accepted bid is used as a floor below which their final IFM bid for any remaining capacity is not mitigated. Bid mitigation is then performed by taking the lower of a unit's market bid and their DEB for any remaining capacity (subject to this bid floor). In the base case market simulation, however, IFM market bids for gas-fired units always exceeded their DEBs, since initial IFM bids in the base scenario were set at marginal cost + 20 percent, while DEBs were set at marginal cost +10 percent.

[23] However, during this hour, since the quantity clearing the IFM in this hour (871 MW) was significantly less than the quantity dispatched in the AC run (1,055 MW), the highest prices of bids dispatched and LMPs in the AC cannot be directly compared to IFM bids and LMPs to assess LMPM effectiveness.

- Finally, the green (leftmost) line represents bids actually clearing the IFM market. As shown in Table 15, the quantity of capacity within the LCA clearing the IFM this hour (871 MW) was significantly lower than the quantity dispatched in the AC run (1,055 MW).

Figure 84. IFM Bid Mitigation – San Diego LCA

December 11, HE 13



San Diego – December 11, Hour Ending 17

Table 15 also provides a summary LMPM and IFM results for Hour Ending 17 of the December 11 local market power scenario for the San Diego LCA. Figure 85 provides a graphical summary of LMPM and IFM bids and dispatches for this hour.

As shown in Table 15 and Figure 85, during these hours, a $400 bid was dispatched in the IFM and the highest LMP in the San Diego LCA reached $554. However, a review of market results for this day indicates that these high LMPs on this day are not attributable to any failure of LMPM provisions. Instead, the high LMPs on this day within the San Diego LCA are attributable to the fact that the IFM software did not reach its target quality of solution threshold. As explained in a December 23 review of MRTU results with stakeholders:[24]

- On this day, the IFM solution reached within the initial solution time provided had an extremely high MIP Gap (12 percent), compared to a target level of less than 1 percent.[25]

[24] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, December 23, 2008, slide 5-7, presentation Dec 23, 2008 http://www.caiso.com/20a6/20a67f452b390.pdf

[25] The MIP ("Mixed Integer Programming") Gap is the measure of the optimality of a solution (relative to a theoretical minimum that could be reached ignoring mixed integer constraints). The smaller the MIP Gap, the closer the solution is to this theoretical optimal level.

However, in order to complete the IFM market on a timeline that would allow participants to proceed with the real-time simulation tests being run during this period, the CAISO did not re-run the software allowing for additional solution time to reach a more optimal solution.

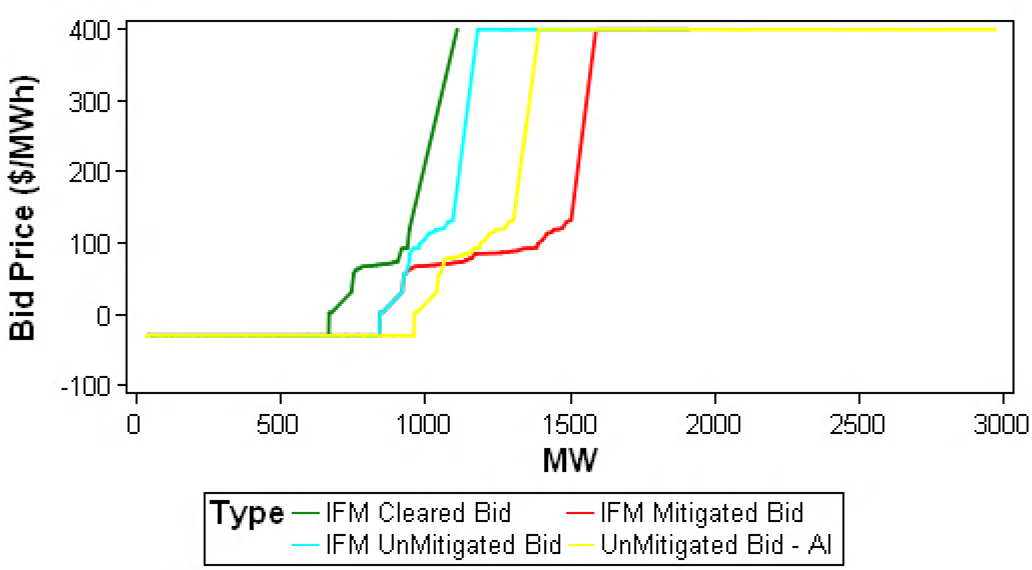
- Under this less optimal solution, a transmission constraint into the San Diego area (Miguel) was violated slightly during some hours, and had extremely high shadow prices ($660-$1,200) during Hours Ending 15-19.
- In addition, under this less optimal IFM solution, at least one Reliability Must Run (RMR) resource that was committed in the AC run was not committed in the IFM.
- Thus, under this less optimal solution, the IFM software had – in effect – violated the Miguel constraint (and incurred the resulting penalty price in the objective function), rather than committing an extra RMR unit within the San Diego area.
- After re-running the same IFM scenario off-line with additional solution time, the MIP Gap was reduced to expected levels (.13 percent).
- Under this more optimal solution, an additional RMR unit that was dispatched in the AC run was also dispatched in the IFM, with shadow prices for congestion on the Miguel constraint being lowered to approximately $73.

In order to avoid such situations after MRTU implementation, the CAISO has indicated it will continue to tune penalty prices used in the MRTU software and allow for sufficient solution time to meet target MIP Gap levels.

In addition, in light of the very significant market impacts that could result from high MIP Gap levels, DMM is specifically recommending that in the event a similar situation should occur under actual market operations, the CAISO should be prepared to extend the solution time of the market software and re-run the software prior to closing the IFM.

Figure 85. IFM Bid Mitigation – San Diego LCA

December 11, HE 17 (with High MIP Gap)



Market Simulation Results for HASP/RTM

LMPM was not triggered during any hour within any LCA during the structured market simulation tests. At least two factors contributed to these results:

- As previously noted, a significantly greater amount of capacity within these LCAs was self-scheduled in the RTM in the December 11 market simulation than in the IFM for that operating day, while less capacity was bid at the $400/MW level (see Figure 82).
- In addition, as discussed in Section III of this report, the relatively high prices observed in the HASP and RTM during the December 9-12 market simulation tests during some hours can be primarily attributed to *system-level* conditions, reflecting limitations of the amount of energy available to meet *overall system energy requirements*. Such conditions can tend to prevent LMPM provisions from being triggered by raising overall system energy prices and reducing the amount of additional energy dispatched from units within transmission constrained areas in the AC run (relative to the CC run) of the LMPM procedures performed prior to the hourly HASP/RTM run.

DMM will continue to test the LMPM procedures incorporated in the HASP/RTM model using bidding scenarios specifically designed to test these procedures in different transmission constrained areas.

Appendix A: Summary of IFM Local Market Power Mitigation Results for Major Local Capacity Areas

Market Simulation Trade Days December 9-12, 2008

Description of Data in Tables A-1 through A-16

Total Bids (MW). Total capacity bid into IFM during hour by all resources within LCA. Includes self-scheduled energy and non-gas units. *Note: Data for December 10 excludes some bids missing from database available for use in this analysis. Actual bid quantities are approximately equal to other days.*

Dispatched MW - CC Run. Total capacity (MW) within LCA dispatched in the Competitive Constraints (CC) run of the pre-market local market power mitigation procedures. CC run based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW - AC Run. Total capacity (MW) within LCA dispatched in the All Constraints (AC) run of the pre-market local market power mitigation procedures. AC run based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW – IFM. Total capacity (MW) within LCA dispatched in the IFM, after any bid mitigation occurring based on results of CC and AC runs.

Mitigation – Units. Number of units within LCA subject to potential bid mitigation. Unit is subject to bid mitigation if dispatched in AC run at a higher level than in CC run. *Note: In some hours, due to rounding of CC and AC dispatch totals, mitigation may occur when AC dispatch level is < 1 MW higher than AC dispatch level.*

Mitigation – MW. Total capacity of the units within LCA subject to bid mitigation, i.e., the capacity greater than the units dispatch in the CC run up to the units maximum bid level (typically PMax). It should be noted that whether these units' market bids for this portion of their capacity was actually mitigated (i.e., lowered) depends on two factors. First, the units highest accepted bid in the CC run is a floor below which bid prices for additional capacity above this level cannot be lower. Second, the market bids are only lowered if they are greater than the unit's DEB for that portion of their capacity.

AC Run – Max Bid. Maximum bid within LCA cleared in AC run (based on market bids prior to any mitigation). Can provide an indication of the potential impact of mitigation when compared to maximum bid dispatched in IFM (after mitigation). However, maximum bid in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative bid prices representing negative bids placed on self-schedules and capacity clearing AC run excluded.

AC Run – Max LMP. Maximum LMP within LCA cleared in AC run (based on market bids prior to any mitigation). Can provide an indication of the potential impact of mitigation when compared to maximum LMP in the (after mitigation). However, maximum LMP in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative LMPs reflect represent negative bids placed on self-schedules, and capacity clearing AC run.

IFM – Max Bid. Maximum bid within LCA cleared in IFM (after any mitigation). Can provide indication of whether high LMPs within LCA are set by resources within LCA or system conditions.

IFM – Max LMP. Maximum LMP within LCA in IFM.

Table A-1. Summary of IFM and LMPM Results: Bay Area LCA

December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	AC Run	IFM	Mitigation Units	MW	AC Run Max. Bid	Max. LMP	IFM Max. Bid	Max. LMP
1	5,921	1,804	1,804	1,781	0			-$31	$77	$56
2	5,882	1,352	1,352	1,112	0			$48	$2	$49
3	5,862	1,152	1,152	962	0			$32	$2	$42
4	5,851	1,139	1,139	949	0			-$32	$2	$38
5	5,830	1,112	1,112	922	0			-$32	$2	$38
6	5,835	1,138	1,138	922	0			-$32	$2	$49
7	5,737	1,027	1,027	837	0			-$26	$2	$36
8	5,739	1,066	1,066	1,066	0			$52	$53	$50
9	5,745	1,847	1,847	1,655	0		$60	$63	$60	$61
10	5,753	2,436	2,436	2,305	0		$63	$69	$63	$66
11	5,769	2,764	2,764	2,663	0			-$56	$74	$71
12	5,785	3,368	3,368	2,992	0			-$23	$72	$73
13	5,852	4,020	4,020	3,149	0			-$64	$73	$73
14	5,889	4,562	4,562	3,409	0			-$180	$75	$77
15	5,896	4,828	4,795	4,149	0			-$43	$75	$81
16	5,887	5,097	5,066	4,395	0			-$41	$83	$86
17	5,905	5,083	5,054	4,406	0			-$42	$83	$89
18	5,922	5,045	5,014	4,386	0			-$234	$80	$86
19	5,893	4,913	4,913	4,276	0			-$65	$75	$81
20	5,903	4,579	4,579	3,961	0			-$63	$75	$80
21	5,886	4,351	4,351	3,254	0			-$69	$74	$80
22	5,863	4,218	4,218	3,147	0			-$89	$74	$77
23	5,956	3,489	3,489	3,022	0			$14	$74	$74
24	5,923	2,859	2,859	2,800	0			-$32	$72	$69

Table A-2. Summary of IFM and LMPM Results: Bay Area LCA December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	5,237	1,902	1,902	2,026	0			$59	$72	$54
2	5,200	1,372	1,372	1,879	0			-$26	$72	$50
3	5,180	1,287	1,287	1,667	0			-$32	$60	$38
4	5,169	1,274	1,274	1,524	0			$42	$2	$38
5	5,151	1,265	1,265	1,250	0			-$26	$2	$38
6	5,156	1,295	1,295	1,295	0			-$32	$72	$48
7	5,068	1,180	1,180	1,165	0			-$31	$2	$37
8	5,060	1,466	1,466	1,201	0			$53	$53	$51
9	5,062	2,266	2,266	1,246	0			-$27	$77	$56
10	5,070	2,675	2,675	1,232	0			-$26	$77	$53
11	5,078	3,195	3,195	1,742	0			-$27	$77	$59
12	5,093	4,177	4,177	2,429	0		$73	-$28	$77	$63
13	5,161	4,144	4,144	2,771	0			-$44	$77	$65
14	5,196	4,564	4,564	2,997	0			-$43	$77	$67
15	5,202	4,959	4,926	2,960	0		$83	-$62	$63	$72
16	5,199	5,049	5,018	3,091	0		$85	-$53	$74	$75
17	5,222	5,075	5,046	3,117	0		$72	-$48	$74	$76
18	5,239	5,078	5,047	3,126	0		$75	-$55	$74	$75
19	5,207	4,938	4,904	3,081	0		$72	-$63	$74	$73
20	5,216	4,662	4,662	2,992	0		$74	-$43	$63	$70
21	5,197	4,320	4,320	2,571	0		$76	$40	$63	$69
22	5,180	4,173	4,173	2,554	0		$74	$14	$63	$70
23	5,273	3,603	3,603	2,529	0		$74	-$27	$63	$67
24	5,240	2,623	2,623	2,123	0			$63	$60	$59

Table A-3. Summary of IFM and LMPM Results: Bay Area LCA December 11, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	5,919	1,944	1,944	2,151	0			-$31	$400	$53
2	5,882	1,222	1,222	1,651	0			-$31	$400	$48
3	5,862	1,152	1,152	1,212	1	371	$49	$43	$2	$48
4	5,851	1,139	1,139	949	1	371	$49	$43	$2	$48
5	5,833	1,115	1,115	925	0			-$32	$2	$45
6	5,838	1,140	1,140	925	0			$48	$2	$54
7	5,751	1,030	1,030	840	0			$37	$2	$37
8	5,742	1,130	1,130	826	0			$52	$2	$53
9	5,744	1,876	1,876	1,063	0		$60	$63	$53	$65
10	5,752	2,515	2,515	1,712	0			-$103	$63	$66
11	5,760	2,835	2,835	2,119	0			-$96	$63	$70
12	5,775	3,334	3,334	2,591	0			$47	$71	$73
13	5,843	3,560	3,560	2,842	0			-$64	$74	$73
14	5,878	3,819	3,819	3,046	0			-$77	$74	$78
15	5,884	4,089	4,089	3,293	0			$27	$88	$96
16	5,881	4,167	4,167	3,292	0			$54	$88	$116
17	5,904	4,193	4,193	3,335	0			$89	$88	$124
18	5,921	4,216	4,216	3,358	0			$29	$88	$115
19	5,889	4,112	4,112	3,329	0			$29	$88	$98
20	5,898	3,910	3,910	3,157	0			-$25	$75	$79
21	5,879	3,529	3,529	2,696	0			-$68	$75	$82
22	5,862	3,467	3,467	2,646	0			-$87	$74	$78
23	5,955	3,037	3,037	2,660	0			-$102	$74	$73
24	5,922	2,783	2,783	2,593	0			-$31	$73	$65

Table A-4. Summary of IFM and LMPM Results: Bay Area LCA
December 12, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	5,920	1,589	1,589	1,875	0			$59	$63	$52
2	5,882	982	982	1,580	0			$53	$60	$42
3	5,860	961	961	1,401	0			$6	$2	$39
4	5,850	947	947	1,137	0			-$27	$2	$44
5	5,828	921	921	1,111	0			-$27	$2	$44
6	5,836	923	923	1,113	0			-$32	$2	$46
7	5,753	837	837	1,027	0			-$28	$2	$36
8	5,743	821	821	1,011	0			-$28	$2	$48
9	5,745	1,317	1,312	1,247	0			-$28	$53	$60
10	5,750	2,158	2,158	1,758	0			-$28	$63	$67
11	5,764	2,756	2,756	2,308	0			-$101	$74	$70
12	5,784	3,102	3,102	2,673	0			-$90	$74	$69
13	5,847	3,521	3,521	2,958	0			-$69	$74	$71
14	5,881	3,979	3,979	3,155	0			-$64	$75	$74
15	5,887	4,170	4,137	3,394	0			-$267	$75	$78
16	5,878	4,160	4,141	3,694	1	96	$88	$108	$75	$83
17	5,896	4,181	4,162	3,718	1	96	$88	$105	$80	$85
18	5,914	4,203	4,172	3,734	0			-$126	$75	$82
19	5,886	4,116	4,082	3,505	0			-$303	$75	$79
20	5,896	3,737	3,737	3,111	0			-$64	$75	$76
21	5,878	3,373	3,373	2,676	0			-$68	$71	$75
22	5,865	3,241	3,241	2,705	0			-$59	$74	$75
23	5,953	2,969	2,985	2,688	2	178	$74	$77	$74	$71
24	5,923	2,569	2,569	2,535	0			-$31	$73	$66

Table A-5. Summary of IFM and LMPM Results: Ventura/Big Creek LCA
December 9, 2008 IFM Market Simulation

	Total	Dispatched MW			Mitigation		AC Run		IFM	
Hour	Bids (MW)	CC Run	AC Run	IFM	Units	MW	Max. Bid	Max. LMP	Max. Bid	Max. LMP
1	4,580	1,575	1,575	1,575	0			-$26	$46	$53
2	4,592	1,434	1,434	1,434	0			$46	$21	$45
3	4,596	1,438	1,438	1,438	0			$23	$21	$37
4	4,599	1,441	1,441	1,441	0			-$25	$21	$36
5	4,602	1,444	1,444	1,444	0			-$25	$21	$36
6	4,602	1,444	1,444	1,444	0			-$25	$21	$44
7	4,657	1,499	1,499	1,499	0			-$21	$21	$34
8	4,667	1,508	1,508	1,508	0			$49	$21	$46
9	4,702	1,950	1,950	1,757	0			$59	$56	$58
10	4,638	2,417	2,417	1,883	0		$59	$64	$59	$61
11	4,716	2,870	2,870	2,515	0			-$46	$64	$66
12	4,709	3,357	3,357	2,703	0			-$18	$68	$68
13	4,694	3,362	3,362	2,707	0			-$54	$69	$69
14	4,672	3,642	3,642	2,785	0			-$155	$71	$72
15	4,644	3,805	3,805	2,910	0			-$35	$73	$76
16	4,621	4,069	4,069	3,217	0			-$34	$76	$80
17	4,600	4,093	4,093	3,281	0			-$35	$78	$81
18	4,560	3,992	3,992	3,201	0			-$203	$76	$79
19	4,539	3,849	3,849	2,962	0			-$55	$73	$75
20	4,539	3,501	3,501	2,652	0			-$53	$71	$73
21	4,549	3,460	3,460	2,693	0			-$58	$72	$72
22	4,571	3,138	3,138	2,487	0			-$77	$67	$70
23	4,541	2,898	2,898	2,358	0			$14	$66	$67
24	4,528	2,509	2,509	2,263	0			-$27	$59	$64

Table A-6. Summary of IFM and LMPM Results: Ventura/Big Creek LCA December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,138	1,702	1,702	1,762	0			$56	$59	$49
2	4,150	1,434	1,434	1,574	0			-$21	$59	$48
3	4,154	1,438	1,438	1,438	0			-$26	$21	$36
4	4,157	1,441	1,441	1,441	0			$40	$21	$36
5	4,160	1,444	1,444	1,444	0			-$21	$21	$36
6	4,160	1,444	1,444	1,444	0			-$26	$21	$45
7	4,215	1,499	1,499	1,499	0			-$25	$21	$35
8	4,225	1,528	1,529	1,662	1	222	$46	$50	$21	$47
9	4,260	1,987	1,987	1,544	0			-$22	$21	$50
10	4,196	2,431	2,431	1,480	0			-$21	$21	$50
11	4,274	2,806	2,806	1,693	0			-$22	$46	$56
12	4,267	3,052	3,052	2,097	0			-$23	$59	$61
13	4,252	3,205	3,205	2,174	0			-$37	$59	$63
14	4,230	3,673	3,673	2,360	0			-$36	$59	$65
15	4,202	4,016	4,016	2,603	0		$75	-$53	$69	$70
16	4,179	4,092	4,092	2,657	0		$82	-$44	$71	$73
17	4,158	4,071	4,071	2,696	0		$82	-$40	$73	$75
18	4,118	3,992	3,992	2,596	0		$76	-$47	$71	$73
19	4,097	3,841	3,841	2,515	0		$76	-$54	$69	$71
20	4,097	3,362	3,362	2,395	0		$46	-$36	$66	$67
21	4,107	3,261	3,261	2,345	0		$46	$38	$64	$65
22	4,129	2,953	2,953	2,056	0		$46	$15	$64	$65
23	4,099	2,767	2,767	2,020	0		$46	-$24	$64	$63
24	4,086	2,453	2,449	1,707	0		$46	$59	$59	$55

Table A-7. Summary of IFM and LMPM Results: Ventura/Big Creek LCA December 11, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,580	1,675	1,675	1,522	0			-$26	$56	$51
2	4,592	1,434	1,434	1,434	0			-$25	$21	$45
3	4,596	1,438	1,438	1,438	0			$42	$21	$38
4	4,599	1,441	1,441	1,441	0			$42	$21	$36
5	4,602	1,444	1,444	1,444	0			-$25	$56	$37
6	4,602	1,444	1,444	1,444	0			$47	$56	$44
7	4,657	1,499	1,499	1,499	0			$36	$21	$35
8	4,667	1,508	1,509	1,662	1	222	$46	$50	$21	$50
9	4,702	1,960	1,960	1,817	1	450	$59	$61	$56	$61
10	4,638	2,138	2,138	2,078	0			-$85	$64	$62
11	4,716	2,634	2,634	2,195	0			-$79	$67	$66
12	4,709	2,988	2,988	2,420	0			$46	$69	$71
13	4,694	2,972	2,972	2,572	0			-$54	$70	$70
14	4,672	3,051	3,051	2,780	0			-$66	$70	$76
15	4,644	3,023	3,023	2,888	0			$26	$70	$99
16	4,621	3,000	3,000	2,922	0			$46	$70	$121
17	4,600	2,980	2,980	2,901	0			$85	$70	$129
18	4,560	2,939	2,939	2,861	0			$28	$70	$121
19	4,539	2,918	2,918	2,840	0			$28	$70	$99
20	4,539	2,896	2,896	2,764	0			-$20	$70	$74
21	4,549	2,929	2,929	2,774	0			-$58	$70	$74
22	4,571	2,928	2,928	2,796	0			-$76	$70	$72
23	4,541	2,766	2,766	2,371	0			-$88	$67	$67
24	4,528	2,233	2,233	2,043	0			-$27	$63	$61

Table A-8. Summary of IFM and LMPM Results: Ventura/Big Creek LCA December 12, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,580	1,645	1,645	1,492	0			$56	$63	$49
2	4,592	1,484	1,484	1,484	0			$49	$21	$39
3	4,596	1,488	1,488	1,488	0			-$9	$21	$36
4	4,599	1,491	1,491	1,491	0			-$28	$21	$36
5	4,602	1,494	1,494	1,494	0			-$28	$21	$36
6	4,602	1,494	1,494	1,494	0			-$25	$21	$42
7	4,657	1,549	1,549	1,549	0			-$23	$21	$33
8	4,667	1,558	1,558	1,558	0			-$22	$21	$44
9	4,702	1,830	1,830	1,663	0			-$23	$46	$56
10	4,638	2,324	2,324	1,803	0			-$23	$63	$62
11	4,716	2,976	2,976	2,442	0			-$83	$63	$65
12	4,709	3,376	3,376	2,665	0			-$74	$68	$66
13	4,694	3,497	3,497	2,816	0			-$58	$68	$68
14	4,672	3,748	3,748	2,838	0			-$54	$67	$70
15	4,644	4,206	4,206	3,284	0			-$229	$74	$75
16	4,621	4,304	4,304	3,415	0			$59	$74	$79
17	4,600	4,288	4,288	3,514	0			$76	$76	$81
18	4,560	4,182	4,182	3,354	0			-$107	$74	$78
19	4,539	4,019	4,019	3,207	0			-$262	$72	$75
20	4,539	3,623	3,623	2,845	0			-$54	$69	$71
21	4,549	3,672	3,672	2,625	0			-$57	$69	$71
22	4,571	3,292	3,292	2,547	0			-$50	$69	$70
23	4,541	2,657	2,657	2,337	0			$66	$64	$66
24	4,528	2,263	2,263	2,010	0			-$27	$59	$61

Table A-9. Summary of IFM and LMPM Results: LA Basin

December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	9,825	3,898	3,898	3,888	0			-$30	$58	$53
2	9,798	3,716	3,716	3,716	0			$45	$58	$45
3	9,850	3,755	3,755	3,735	0			$23	$47	$37
4	9,853	3,649	3,649	3,652	0			-$30	$34	$36
5	9,852	3,690	3,690	3,650	0			-$30	$34	$36
6	9,851	3,690	3,690	3,762	0			-$30	$58	$44
7	9,845	3,640	3,640	3,756	0			-$26	$58	$34
8	9,856	3,830	3,830	3,800	0		$47	$50	$58	$47
9	9,861	3,975	3,975	3,991	0		$65	$60	$67	$59
10	9,854	4,295	4,295	4,247	0		$47	$65	$68	$62
11	9,847	4,667	4,667	4,534	0		$58	$14	$69	$67
12	9,839	5,391	5,391	4,842	0		$58	$34	$71	$71
13	9,862	5,754	5,754	5,071	0			$16	$71	$71
14	9,876	5,924	5,924	5,630	0			-$36	$73	$75
15	9,872	6,475	6,475	5,925	0			$37	$81	$79
16	9,867	6,509	6,509	6,004	0			$39	$81	$84
17	9,866	6,541	6,541	6,023	0			$37	$81	$86
18	9,855	6,412	6,412	5,980	0			-$55	$81	$84
19	9,866	6,408	6,408	5,934	0			$16	$81	$78
20	9,865	6,302	6,302	5,564	0			$17	$73	$76
21	9,816	6,137	6,137	5,276	0			$12	$79	$75
22	9,774	5,503	5,503	5,215	0			-$9	$79	$73
23	9,772	5,144	5,144	4,655	0			$40	$69	$69
24	9,749	4,547	4,547	4,413	0			-$30	$68	$65

Table A-10. Summary of IFM and LMPM Results: LA Basin LCA

December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	7,150	4,039	4,039	3,930	0		$58	$56	$58	$50
2	7,123	3,844	3,844	3,524	0		$58	-$25	$58	$48
3	7,175	3,804	3,804	3,544	0			-$30	$58	$36
4	7,178	3,712	3,712	3,452	0			$39	$34	$36
5	7,177	3,751	3,751	3,451	0			-$25	$34	$36
6	7,176	3,750	3,750	3,490	0			-$30	$41	$45
7	7,170	3,704	3,704	3,444	0			-$30	$34	$36
8	7,181	3,938	3,938	3,496	0			$51	$41	$48
9	7,186	4,099	4,099	3,625	0			-$26	$54	$51
10	7,179	4,509	4,509	3,693	0			-$25	$58	$51
11	7,172	4,911	4,911	3,789	0			-$26	$67	$57
12	7,164	5,495	5,495	4,028	0		$85	-$27	$67	$62
13	7,187	5,859	5,859	4,178	0			-$22	$67	$65
14	7,201	6,316	6,316	4,304	0		$71	-$20	$67	$66
15	7,197	6,352	6,352	4,435	0		$71	-$34	$79	$72
16	7,192	6,461	6,461	4,553	0		$71	-$24	$81	$76
17	7,191	6,460	6,460	4,580	0		$71	-$20	$81	$78
18	7,180	6,384	6,384	4,573	0			-$28	$81	$76
19	7,191	6,384	6,384	4,467	0			-$35	$81	$73
20	7,190	6,281	6,281	4,307	0			-$21	$79	$69
21	7,141	6,213	6,213	4,226	0		$71	$44	$79	$67
22	7,099	5,710	5,710	4,176	0		$71	$18	$67	$67
23	7,097	5,049	5,049	4,003	0			-$27	$67	$64
24	7,074	4,577	4,577	3,561	0			$59	$58	$56

Table A-11. Summary of IFM and LMPM Results: LA Basin LCA

December 11, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	9,987	3,778	3,778	3,831	0		$73	-$30	$112	$51
2	9,960	3,554	3,554	3,516	0			-$30	$72	$45
3	10,012	3,511	3,511	3,557	0			$41	$47	$38
4	10,015	3,514	3,514	3,554	0			$41	$47	$37
5	10,014	3,512	3,512	3,547	0			-$30	$47	$37
6	10,013	3,512	3,512	3,512	0			$46	$41	$45
7	10,007	3,463	3,463	3,543	0			$36	$47	$36
8	10,018	3,638	3,638	3,662	0		$47	$51	$58	$50
9	10,023	3,433	3,433	3,675	0			$62	$67	$62
10	10,016	4,106	4,106	3,991	0			-$22	$81	$63
11	10,009	4,680	4,680	4,454	0			-$15	$72	$67
12	10,001	5,720	5,720	4,831	0			$67	$81	$75
13	10,024	6,431	6,431	5,024	0			$9	$81	$76
14	10,038	6,906	6,906	5,451	0			$3	$81	$95
15	10,034	7,731	7,731	6,272	0			$55	$87	$197
16	10,028	7,997	7,997	6,923	0			$69	$112	$296
17	10,028	8,032	8,032	6,924	0			$256	$112	$319
18	10,017	7,940	7,940	6,903	0			$56	$112	$296
19	10,028	7,549	7,549	6,693	0			$56	$90	$195
20	10,027	7,120	7,120	5,871	0			$30	$81	$89
21	9,977	7,074	7,074	5,443	0			$7	$81	$80
22	9,936	6,256	6,256	5,001	0			-$7	$81	$78
23	9,934	5,399	5,399	4,656	0			-$21	$81	$69
24	9,911	4,392	4,392	4,358	0			-$30	$70	$62

Table A-12. Summary of IFM and LMPM Results: LA Basin LCA

December 12, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	9,825	3,866	3,866	3,866	0			$55	$69	$49
2	9,798	3,732	3,732	3,653	0			$49	$58	$39
3	9,850	3,711	3,711	3,724	0			-$9	$58	$36
4	9,853	3,611	3,611	3,703	0			-$33	$58	$36
5	9,852	3,650	3,650	3,610	0			-$33	$34	$36
6	9,851	3,649	3,649	3,639	0			-$30	$41	$42
7	9,845	3,600	3,600	3,600	0			-$27	$2	$33
8	9,856	3,775	3,775	3,724	0			-$27	$47	$45
9	9,861	3,826	3,826	3,815	0			-$28	$67	$56
10	9,854	3,742	3,742	3,941	0			-$27	$69	$63
11	9,847	4,135	4,135	4,334	0			-$20	$81	$66
12	9,839	4,790	4,790	4,580	0			-$9	$79	$68
13	9,862	5,275	5,275	4,708	0			$12	$81	$70
14	9,876	5,736	5,736	5,236	0			$16	$73	$72
15	9,872	5,902	5,902	5,504	0			-$70	$79	$77
16	9,867	6,203	6,203	5,725	0			$95	$81	$82
17	9,866	6,327	6,327	5,756	0			$98	$81	$84
18	9,855	6,253	6,253	5,713	0			-$2	$81	$81
19	9,866	6,138	6,138	5,617	0			-$87	$79	$77
20	9,865	6,092	6,092	5,314	0			$16	$73	$73
21	9,816	5,930	5,930	5,013	0			$13	$71	$73
22	9,774	5,555	5,555	4,863	0			$16	$81	$72
23	9,772	4,803	4,803	4,532	0			$69	$79	$68
24	9,749	4,248	4,248	4,187	0			-$30	$79	$62

Table A-13. Summary of IFM and LMPM Results: San Diego LCA

December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	AC Run	IFM	Mitigation Units	MW	AC Run Max. Bid	Max. LMP	IFM Max. Bid	Max. LMP
1	2,920	566	566	598	0			-$29	$70	$51
2	2,919	517	517	517	0			$44	$31	$43
3	2,919	517	517	517	0			$22	$31	$36
4	2,919	517	517	517	0			-$29	$31	$34
5	2,919	497	497	517	0			-$29	$31	$34
6	2,954	532	532	552	0			-$29	$31	$42
7	2,969	547	547	567	0			-$25	$31	$33
8	2,969	547	547	567	0			$48	$31	$45
9	2,969	622	622	575	0			$59	$57	$57
10	2,969	809	809	788	0			$64	$70	$60
11	2,971	885	970	868	5	85	$92	$93	$70	$65
12	2,971	1,178	1,234	1,041	6	56	$92	$98	$70	$70
13	2,971	1,220	1,316	1,185	8	134	$111	$109	$70	$72
14	2,971	1,340	1,471	1,264	7	132	$111	$135	$75	$78
15	2,970	1,493	1,653	1,581	7	188	$113	$129	$82	$84
16	2,970	1,588	1,792	1,744	8	218	$113	$130	$87	$92
17	2,970	1,608	1,832	1,800	9	254	$113	$129	$88	$95
18	2,970	1,563	1,731	1,784	7	188	$113	$161	$87	$91
19	2,970	1,411	1,554	1,657	7	188	$111	$111	$82	$83
20	2,970	1,251	1,383	1,472	9	150	$111	$110	$77	$79
21	2,970	1,241	1,333	1,491	9	98	$99	$105	$77	$77
22	2,970	1,160	1,220	1,149	3	67	$85	$86	$70	$74
23	2,970	884	895	847	2	18	$70	$70	$70	$67
24	2,955	729	729	729	0			-$29	$57	$63

Table A-14. Summary of IFM and LMPM Results: San Diego LCA

December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	2,174	526	526	518	0		$57	$54	$31	$48
2	2,173	517	517	517	0			-$24	$31	$46
3	2,173	517	517	517	0			-$29	$31	$34
4	2,173	517	517	517	0			$38	$31	$34
5	2,173	517	517	517	0			-$24	$31	$34
6	2,208	552	552	552	0			-$30	$31	$43
7	2,223	547	547	547	0			-$30	$31	$35
8	2,223	600	600	527	0			$49	$31	$46
9	2,223	600	600	527	0			-$26	$31	$49
10	2,223	825	825	557	0			-$24	$31	$50
11	2,225	1,021	1,021	631	0			-$26	$54	$55
12	2,225	1,222	1,222	687	0			-$26	$57	$60
13	2,225	1,181	1,214	725	5	41	$76	$93	$57	$62
14	2,225	1,269	1,322	829	6	63	$76	$93	$70	$64
15	2,224	1,573	1,627	1,131	5	60	$70	$110	$70	$72
16	2,224	1,678	1,737	1,202	5	62	$70	$119	$76	$80
17	2,224	1,712	1,789	1,199	5	114	$70	$123	$76	$81
18	2,224	1,658	1,712	1,212	5	62	$70	$111	$76	$79
19	2,224	1,461	1,533	1,112	6	77	$70	$109	$70	$75
20	2,224	1,241	1,292	914	6	56	$76	$93	$70	$67
21	2,224	1,241	1,256	828	2	18	$69	$71	$70	$64
22	2,224	1,160	1,161	828	1	10	$69	$69	$70	$64
23	2,224	904	904	800	0			-$26	$70	$61
24	2,209	833	833	531	0			$42	$70	$54

Table A-15. Summary of IFM and LMPM Results: San Diego LCA
December 11, 2008 IFM Market Simulation (with High MIP Gap Solution)

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	2,920	506	506	498	0			-$29	$31	$49
2	2,919	497	497	497	0			-$29	$31	$43
3	2,919	497	497	497	0			$39	$31	$36
4	2,919	497	497	497	0			$39	$31	$35
5	2,919	497	497	497	0			-$29	$31	$36
6	2,954	532	532	512	0			$44	$31	$43
7	2,969	547	547	527	0			$35	$31	$35
8	2,969	555	555	527	0			$49	$31	$49
9	2,969	593	593	535	0			$60	$57	$60
10	2,969	664	727	633	3	171	$92	$71	$68	$64
11	2,971	766	885	717	4	186	$92	$78	$70	$70
12	2,971	803	972	797	6	174	$92	$94	$73	$82
13	2,971	848	1,055	871	5	326	$92	$93	$73	$84
14	2,971	865	1,108	912	3	309	$92	$96	$92	$120
15	2,970	998	1,243	918	2	297	$89	$90	$119	$317
16	2,970	1,089	1,372	1,031	2	297	$94	$95	$400	$513
17	2,970	1,096	1,427	1,110	6	407	$400	$457	$400	$554
18	2,970	1,043	1,285	1,041	2	297	$89	$90	$400	$513
19	2,970	983	1,230	918	2	297	$89	$90	$119	$313
20	2,970	864	1,103	911	3	309	$92	$93	$92	$108
21	2,970	847	1,063	891	5	326	$92	$93	$85	$90
22	2,970	802	981	870	5	371	$92	$86	$73	$86
23	2,970	745	804	760	3	171	$92	$73	$68	$69
24	2,955	589	589	626	0			-$29	$57	$60

Table A-16. Summary of IFM and LMPM Results: San Diego LCA
December 12, 2008 Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	2,920	506	506	498	0			$54	$31	$47
2	2,919	505	505	497	0			$47	$31	$38
3	2,919	497	497	497	0			-$9	$31	$34
4	2,919	497	497	497	0			-$32	$31	$34
5	2,919	505	505	497	0			-$32	$31	$34
6	2,954	532	532	532	0			-$29	$31	$41
7	2,969	527	547	527	1	300		-$27	$31	$32
8	2,969	580	600	527	1	300		-$26	$31	$43
9	2,969	580	600	545	1	300		-$27	$70	$55
10	2,969	834	854	732	1	300		-$27	$70	$60
11	2,971	947	1,028	832	7	525	$92	$75	$70	$64
12	2,971	1,220	1,281	851	5	345	$92	$86	$70	$66
13	2,971	1,260	1,360	970	9	381	$99	$105	$70	$71
14	2,971	1,310	1,454	1,164	8	432	$111	$109	$70	$73
15	2,970	1,623	1,876	1,313	9	497	$113	$166	$79	$79
16	2,970	1,712	2,145	1,527	13	585	$113	$114	$85	$87
17	2,970	1,712	2,193	1,559	13	585	$113	$115	$85	$90
18	2,970	1,678	1,961	1,553	12	608	$113	$145	$84	$86
19	2,970	1,563	1,736	1,372	7	188	$113	$172	$79	$81
20	2,970	1,280	1,423	1,298	9	150	$111	$109	$74	$74
21	2,970	1,290	1,384	1,292	8	141	$99	$106	$74	$73
22	2,970	1,220	1,276	1,206	6	56	$92	$102	$70	$72
23	2,970	1,117	1,117	886	0			$62	$70	$66
24	2,955	845	845	729	0			-$29	$57	$60

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing documents upon all of the parties listed on the official service list for the above-referenced proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C. this 16th day of January, 2009.

/s/ Bradley R. Miliauskas
Bradley R. Miliauskas