California Independent
System Operator Corporation

Review of CAISO MRTU Market Simulation Results

September 2008 – Performance

Department of Market Monitoring

October 22, 2008

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I. Overview

This report provides a review of the California Independent System Operator (CAISO) market redesign and technology upgrade (MRTU) market performance based on the market simulations of September 2008. It also provides a review of several specific areas that are of particular focus for the Department of Market Monitoring (DMM). These are 1) the effectiveness of the local market power mitigation (LMPM), 2) review of generation operational ramp rates, 3) review of "energy limited" unit designations, and 4) review of divergence of integrated forward market (IFM) and hour-ahead scheduling process (HASP) prices.

In reviewing MRTU market performance, it is important to recognize that the market outcomes of the market simulations are not necessarily indicative of likely market outcomes under actual market operation. The market simulation effort is serving several purposes. First, it is providing an opportunity for market participants to gain experience with participating in the market and to test the robustness of their own systems by submitting a variety of bidding and scheduling scenarios – some of which may not be well aligned with the typical peak summer day being modeled in the market simulation.[1] Second, it is being used to "stress test" the market itself through various structured scenarios involving fairly severe market conditions (e.g., major line outages, supply shortages, etc.). Third, it is an opportunity to test and confirm that the market systems are functioning correctly and consistently. Because bidding and scheduling as well as modeling system conditions are based on achieving these three main objectives, and because of the more fundamental issue of there not being any real dollars at stake in the market simulations, the market outcomes from this exercise are not likely to accurately reflect market outcomes under actual market operation. Nonetheless, there is some value to reviewing the market outcomes to assess whether the results are within a reasonable range given the conditions posed in the market simulation and that any anomalous or extreme market outcomes can be reasonably explained.

In assessing the reasonableness of the market simulation results for any particular day it is important to be mindful of several factors that can have a significant impact on market performance:

1) **The specific scenario(s) being modeled for that day** – Over half of the operating days simulated in September involved a structured scenario.
2) **Any significant changes to the market software** – Numerous patches and modifications to the market software were made in September – some of which may have had a significant impact on market results (e.g., uneconomic adjustment parameter values).
3) **Any significant system failures in the simulation environment** – MRTU markets are dependent on the timely and accurate processing and transferring of information from one system to the next. Any glitches in these processes (e.g., inter-tie schedules not being passed to the real-time market) can produce anomalous market results.
4) **Scheduling and bidding of major resources (load and generation)** – Changes to how larger resources (load and generation) are made available to the market can have

[1] The MRTU market simulations over the past several months are based on the same operating day of July 24, 2007.

significant impacts on market outcomes. For example, low levels of forward scheduling and bidding by load-serving entities (LSEs) can result in low market clearing quantities and prices in the IFM and high quantities and prices in the residual unit commitment (RUC) process.

To the extent practical, DMM tried to include these considerations in evaluating market performance. Appendix A provides a summary table on the specific operating dates for market scenarios. These are often referenced in explaining market outcomes in the main report.

At a very high level, this analysis found the MRTU markets have performed reasonably well during the market simulations in September, with market outcomes that are generally consistent with expectations – with some exceptions noted below. There is nothing we have seen to date from a market performance standpoint that would at this time warrant delaying MRTU implementation. However, we do believe that additional analysis and review of certain aspects of the MRTU market performance are warranted. These analyses, which would require a collaborative effort between DMM and the MRTU Project Team, could be completed over the next 4-5 weeks and would help to confirm whether there are any market performance issues that would warrant a delay in market implementation. Specifically, DMM recommends further review and analysis of the following:

- **Extreme real-time market locational marginal prices (LMPs) –** Our assessment of the real-time market performance found that roughly 2% 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 mitigated – though occasional glitches in the real-time simulation environment may still occur. The rest appear to be correct market optimization outcomes associated with extreme conditions – some of which are induced by particular scenarios. Given the competing objectives of market simulation exercises noted above and non-financially binding nature of the market simulation, it is difficult to judge the extent to which the extreme LMPs observed in the real-time market (RTM) simulations would occur under actual market operation. Nonetheless, DMM recommends that the CAISO continue conducting in-depth analysis of the root cause of extreme LMPs in the October and November market simulations to identify and correct any erroneous modeling or software issues that may be causing these prices.
- **Price divergence between day-ahead and real-time markets –** This analysis 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 is part of a more general trend of much higher prices in the real-time market than the IFM. However, if such significant and systematic price divergences for imports and exports persisted under MRTU, this 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 current observed price divergence between the IFM and the HASP may simply be due to the fact that market clearing load quantities in the IFM are 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 is not due to other factors, the CAISO should consider running 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 with the HASP and IFM market.

- **Reliance on non-resource adequacy units in RUC –** Results from the September market simulations show 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, RUC prices would generally be low if not zero.[2] If non-RA resources are routinely awarded 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. Again, 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. DMM plans to undertake additional analysis to better assess whether sufficient RA capacity is being offered to the day-ahead market. We also recommend 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[3]. Additionally, DMM believes that the CAISO should consider publishing 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.

- **Effectiveness of local market power mitigation –** Based on our analysis to date, the LMPM procedures appear to be working as intended and are effectively mitigating local market power. However, DMM plans to further review LMPM performance over the next month. This additional analysis will include:

    - 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.

[2] 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.

[3] 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% of forecasted demand, likely contributed to higher RUC prices.

  - 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).
  - Continuing to review and monitor default energy bids (DEBs), including DEBs developed under the consultative DEB option.
  - 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:
    - Ramp rates;
    - Start-up and minimum load data; and
    - Requests for treatment as a use-limited energy resource.

- **Skipped or failed LMPM procedures** - Importantly, our analysis on the frequency that the LMPM procedures fail to run in the real-time market indicate that LMPM runs have failed and been skipped in the RTM market simulation as much as 5 percent of hours since September 1.[4] Such failures are generally caused when the software fails to reach a solution in the required amount of time. We recommend the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. DMM will continue to monitor the frequency of any failures of RTM market power mitigation runs during market simulation, and recommends that these failures be formally tracked by the CAISO as a basic market performance metric. 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.

DMM has reviewed its recommendations and findings with CAISO Management and the MRTU Project Team. CAISO Management supports these recommendations and has directed the MRTU Project Team to work with DMM in conducting the additional analyses identified above. We look forward to working with the MRTU Project Team in completing this work.

[4] It should be noted that this assessment may be over-stating the frequency of LMPM failures as the data use for it did 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.

II. General Market Performance

Day-ahead market

This section reviews general market performance for the day-ahead market, which includes the integrated forward market (IFM) for energy and ancillary services and the residual unit commitment (RUC) market. Performance in each of these markets is examined separately, beginning with the energy market.

Day-ahead energy market

This section begins with a review of load aggregation point (LAP) prices for the three default LAPs representing the utility distribution company (UDC) areas of Southern California Edison (SCE), San Diego Gas and Electric (SDGE), and Pacific Gas and Electric (PGE). Since demand can be price responsive in the day-ahead market, extreme LAP prices can be avoided through submitting price-responsive LAP demand, whereas in the real-time market (HASP and real-time dispatch or RTD) demand is largely inelastic and is based on the CAISO forecast of actual system demand.

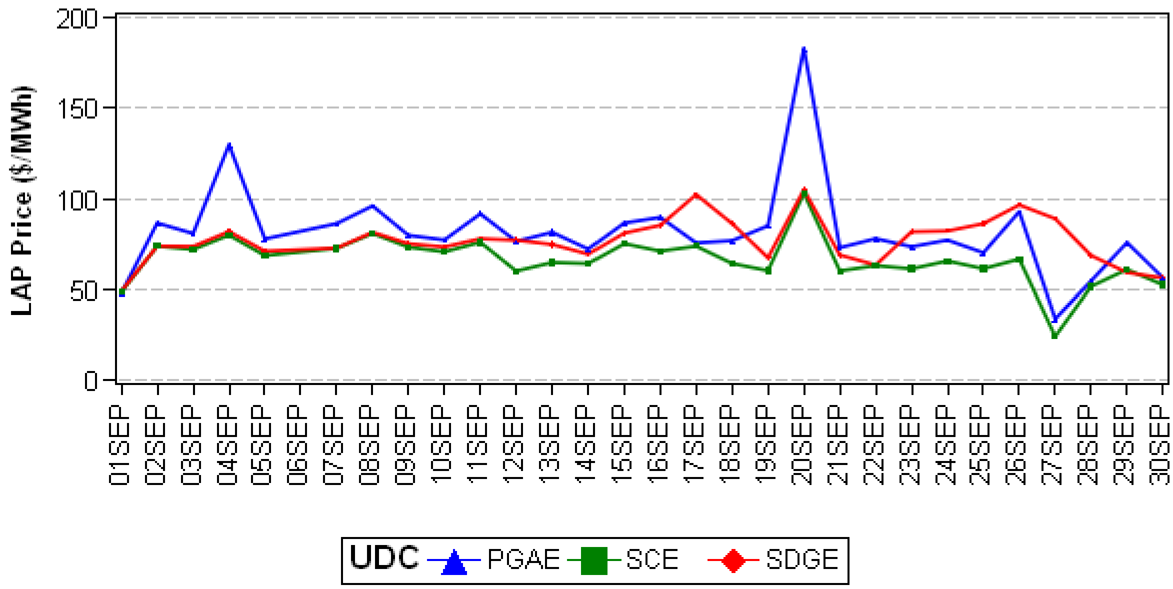
Figure 1 shows the daily weighted average LAP prices for the peak hours for each of the three major LAPs (SCE, SDGE, and PGE). Average peak hour LAP prices ranged from $60 to $90/MWh for most of September. Notable exceptions include the following:

- **September 4 –** The average peak period LAP price for PGE is significantly higher than SCE and SDGE, at approximately $130/MWh. This is likely partially due to congestion on the Dumbartin to Newark line and congestion on the Humboldt Branch Group. These constraints were binding in multiple hours with a shadow price of $5,000/MW. Additionally, the quality of the market optimization for this particular trade day, as measured by the mixed integer programming gap (MIP Gap),[5] was relatively poor, with MIP Gap of 9.02 percent. The MIP Gap on most days is typically in the range of .5 percent.
- **September 20 –** PGE LAP average peak period price is significantly higher than SCE and SDGE, at approximately $183/MWh. SCE and SDGE LAP average peak prices also increased on that day to approximately $100/MWh. This is likely due to the scenario modeled for that day, which called for having insufficient supply in the day-ahead market by reducing supply by 30 percent (Scenario 10).
- **September 27 –** Average peak period prices for the PGE and SCE LAP are significantly lower than SDGE. The low average peak period prices observed for PGE and SCE LAPs for this day are likely due to the scenario employed on that day, which called for testing insufficient demand in the day-ahead IFM by reducing self-scheduled demand by at least 20 percent. The average peak period price for the SDGE LAP is significantly higher than the PGE and SCE. This difference appears to be due to a constraint posed by the Miguel

[5] The MIP Gap measures the relative change in the value of the objective function of the optimization resulting from the last iteration.

nomogram, which required keeping generation up in the San Diego region despite lower load levels.

Figure 1. Daily Weighted Average Peak Hour LAP Prices For September 2008*



* Data missing for September 6

Figure 2 shows the daily weighted average LAP prices for <u>off-peak</u> hours. Off-peak LAP prices were generally in the $40-$60/MWh range (compared to $60-$90/MWh for peak hours). Notable exceptions include:

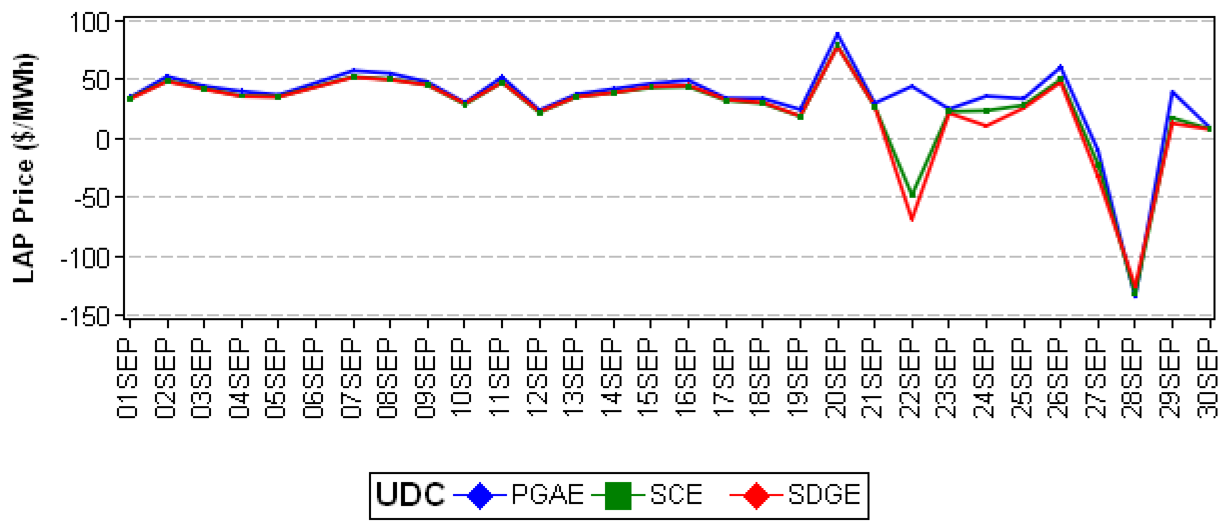
- **September 20** – All three average off-peak period LAP prices were unusually high, with average SCE and SDGE LAP prices above $100/MWh and average PGE LAP prices above $200/MWh in hours 12 through 19. As noted in the review of peak hour LAP prices, this result is likely due to the scenario modeled for that day which called for having insufficient supply in the day-ahead market by reducing supply by 30 percent (Scenario 10).
- **September 22 –** Average off-peak period prices for the SCE and SDGE LAPs were very negative, between -$200 and -$400/MWh in hours 1 and 3. No specific scenarios were run on this day. This result appears to be due to congestion on the Lugo to Vincent lines (see Figure 23). Lugo to Vincent was congested during hours 1-9 with relatively high shadow prices in hours 1 and 3 ($785/MW and $565/MW, respectively), which are the same hours the LAP prices for SCE and SDGE spiked to extreme negative values. The extreme negative LAP prices observed for SCE and SDGE in these hours may have also been due to a relatively high level of resources committed in SP26 in the early morning hours, which appears to be a residual effect from the prior day's market scenario.[6] With an abundance of resources being on-line during the early-off peak hours, mitigating

[6] Scenario 4 was exercised in the IFM on September 21, and involved verifying that energy limits are relaxed for certain generating units.

congestion on Lugo to Vincent required dispatching many units on southern California to their lower economic bound or to a ramp-constraint dispatch down level.

- **September 28** – All three average off-peak period LAP prices are extremely negative at approximately -$130/MWh. On this day, there were extremely low LAP prices for all three LAPs in hours 2-5 (in the -$250 to -$300 range). This was caused by relatively high levels of self-scheduled generation that required backing down self-schedules throughout the system, and resulted in export congestion on certain inter-ties.

Figure 2. Daily Weighted Average Off-Peak Hour LAP Prices For September 2008*



* Data missing for September 6

Figure 3 shows a price duration curve for all LAP prices, separately for each LAP, for the entire month of September, and Figure 4 provides blow-ups of the left and right tails of the price distribution. As evident from these figures, the majority of day-ahead LAP prices (approximately 90 percent) were between $0-$100/MWh in September. The SCE LAP prices were generally lower and exceeded $100/MWh in only about 2 percent of the hours. The PGE LAP prices exceeded $100/MWh in approximately 7 percent of the hours and had the highest extreme LAP prices, with approximately 1.5 percent of them exceeding $200/MWh. The highest PGE LAP price was $298.41, which occurred September 20 in hours 16 and 17[7]. The SDGE LAP prices exceeded $100/MWh in approximately 8 percent of the hours but were not as extreme as the highest PGE LAP prices. Extreme negative LAP prices were rare, occurring in only 1 percent of the hours for all three LAPs.

[7] The high PGE LAP prices observed on this day are due primarily to the scenario of having insufficient supply in the day-ahead market by reducing supply by 30% (Scenario 10).

Figure 3. Duration Curve of Day-Ahead LAP Prices For September 2008

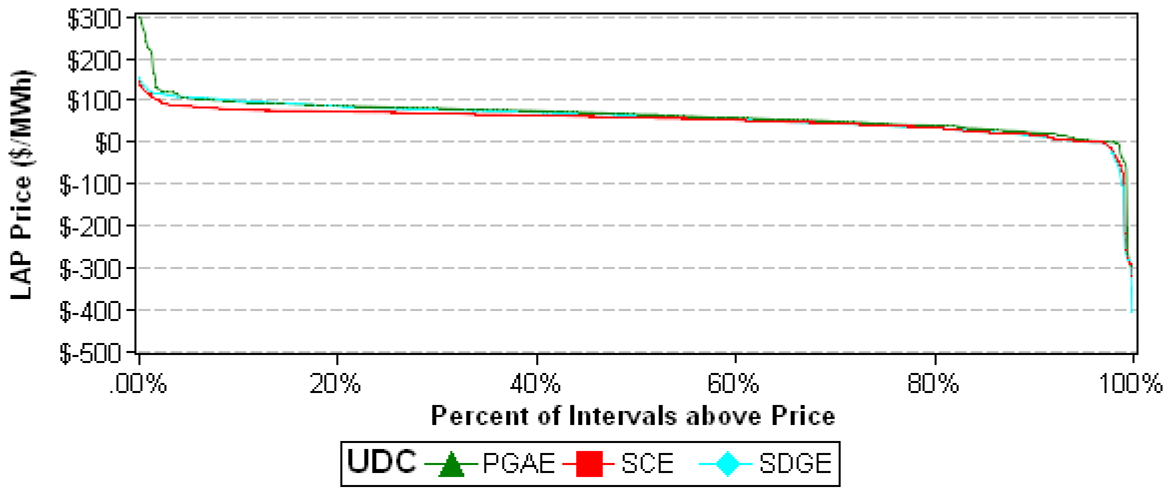


Figure 4. Duration Curves of Upper and Lower 20 percent of Day-Ahead LAP Prices (September 2008)

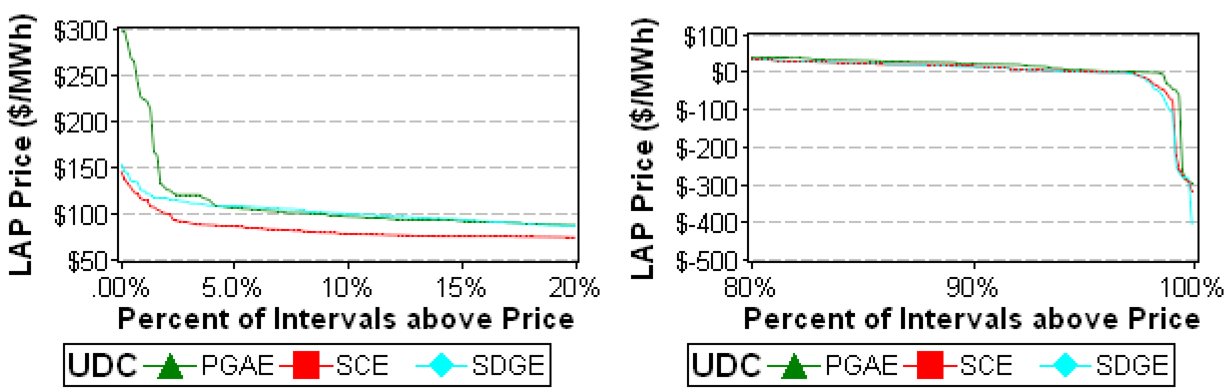


Figure 5 provides a geographic visual of the weighted average day-ahead LMPs. However, only about half of the pricing nodes are represented in this figure. The CAISO is currently in the process of adding the missing nodes to this graphic tool. Nonetheless, the figure does provide some indication of the geographical dispersion of LMP levels. Most notably, the chart shows a cluster of higher average day-ahead LMPs in the Humboldt area of Northern California (west of Redding). As discussed later in the section, the Humboldt area is frequently congested in the market simulation. Also of note are the clusters of higher average day-ahead LMPs (green dots) near the major load pockets of California (San Francisco, Los Angeles, and San Diego). These results are consistent with expectations.

Figure 5. Weighted Average of Day-Ahead LMPs (September Peak Hours)

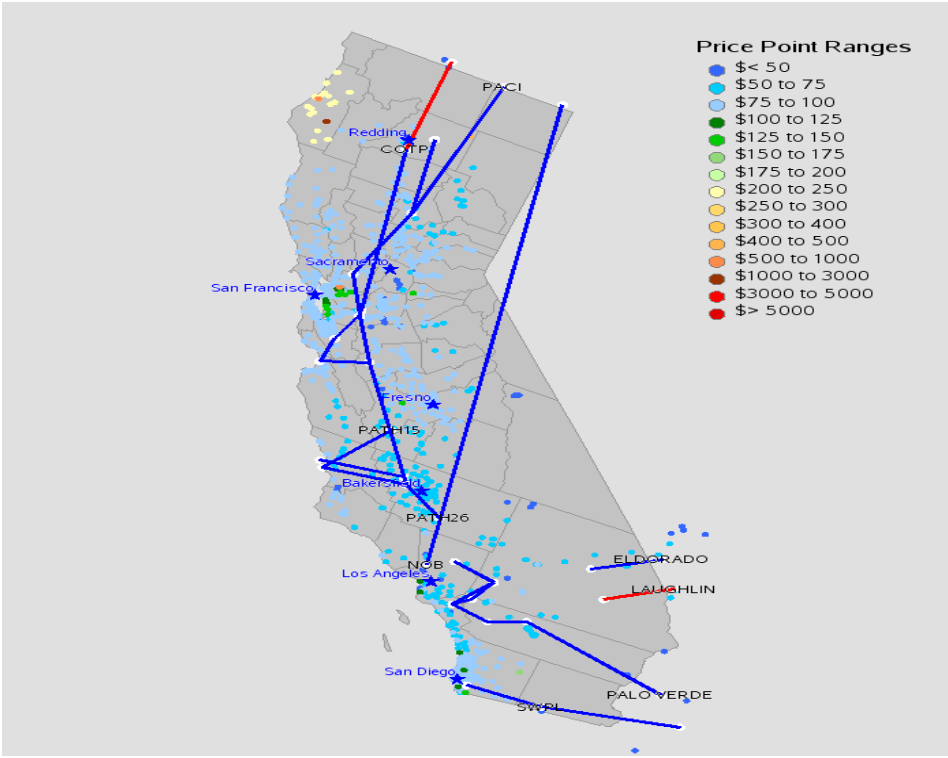


Figure 6 provides a weighted daily average of all day-ahead LMPs along with 5th and 95th percentile, which provides an indication of the variance (spatially and temporally) of day-ahead LMPs. The chart shows a very consistent trend of average LMPs in the $40-$60 range as well as fairly consistent variation (as evident by the 95th and 5th percentiles). Notable exceptions include:

- **September 20** – The weighted average LMP increased to just over $100/MWh. As previously discussed, this is attributable to the scenario modeled for that day which called for having insufficient supply in the day-ahead market by reducing supply by 30 percent (Scenario 10).
- **September 27 –** The weighted average LMP price was also close to zero on this day. The extreme low average LMPs on September 27 can be largely attributable to the scenario for that day (Scenario 11), which created insufficient demand in the day-ahead market by decreasing load self-schedules by 20 percent. This would also explain the extreme negative values for the 5th percentile of LMPs for that day as well.
- **September 28 –** The weighted average LMP price was close to zero on this day. This result is consistent with the observed extreme negative average LAP prices for off-peak hours shown in Figure 2. A review of bids and schedules for this day revealed that in some hours submitted load schedules were less than the sum of self-schedules for supply resources, which required backing down self-scheduled supply. This result may have been an inadvertent extension of the over-generation scenario modeled on the previous day's IFM.

Figure 6. Weighted Average, 5th Percentile, and 95th Percentile of Day-Ahead LMPs

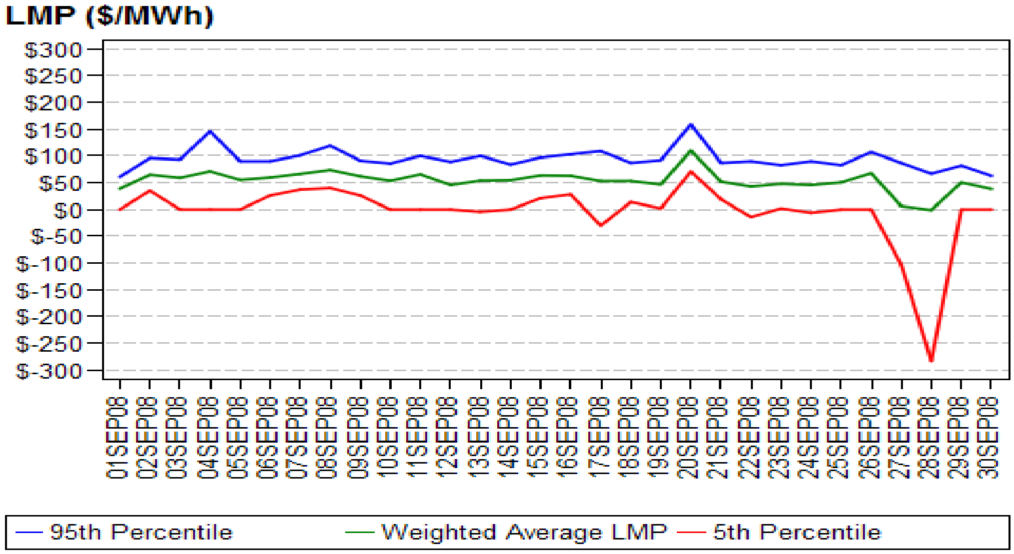
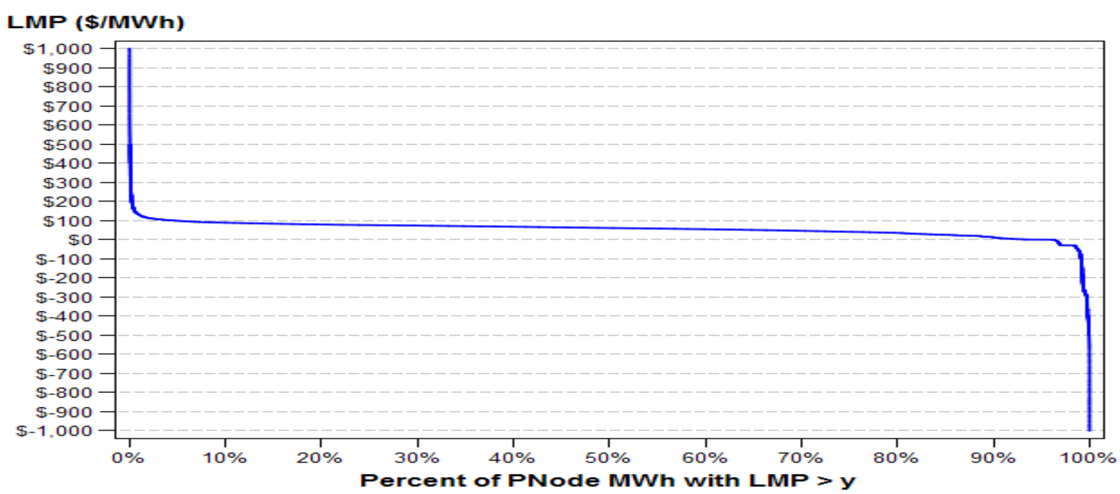


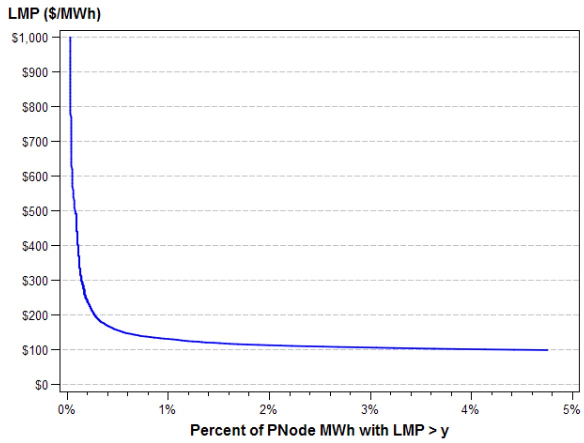
Figure 7 provides a duration curve of all day-ahead nodal market clearing quantities by clearing LMP, and Figure 8 shows blow-ups of the right and left tails of this distribution. As evident from these two figures, only a small amount of quantity (less than .5 percent) cleared the market at extreme LMPs (positive or negative) and the vast majority of day-ahead LMPs (roughly 96 percent) were in a reasonable range of -$30 to $100/MWh.

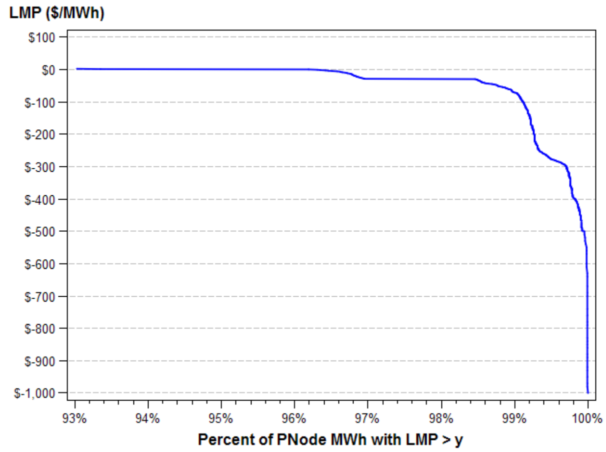
Figure 7. Duration Curve of Day-Ahead Market Clearing Quantities and Price (LMPs)[8]



[8] The scale for Figure 7 is truncated at +/- $1,000/MWh. The high and low LMPs observed during this period were roughly $5,300/MWh and -$7,000/MWh respectively.

Figure 8. Duration Curve Tails of Day-Ahead Market Clearing Quantities and Price (LMPs) For September 2008





Ancillary service prices

Figure 9 to Figure 12 show average daily day-ahead ancillary service prices for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve, respectively. Average prices for these services are within reasonable ranges, with Regulation Up averaging between $8-$35/MW, Spinning Reserve averaging between $1-$23/MW, and Non-Spinning Reserve averaging between $1-$18/MW. The relative values of these services, as reflected in the price differences, are consistent with expectations, with Regulation Up having higher average prices than Spinning Reserve and Spinning Reserve having higher average prices than Non-Spinning Reserve. Regulation Down average prices (Figure 10) generally ranged between $20-$50/MW, with a notable exception on September 28 when the average price for Regulation Down neared $70/MW. The notable up-tick in ancillary service prices (Regulation Up, Spinning Reserve, and Non-Spinning Reserve) observed on September 26 is likely due to the specific scenario executed on that trade day, which called for creating a Spinning Reserve deficiency (Scenario 24a).

Figure 9. Daily Regulation Up MW Procured and Weighted Average Price

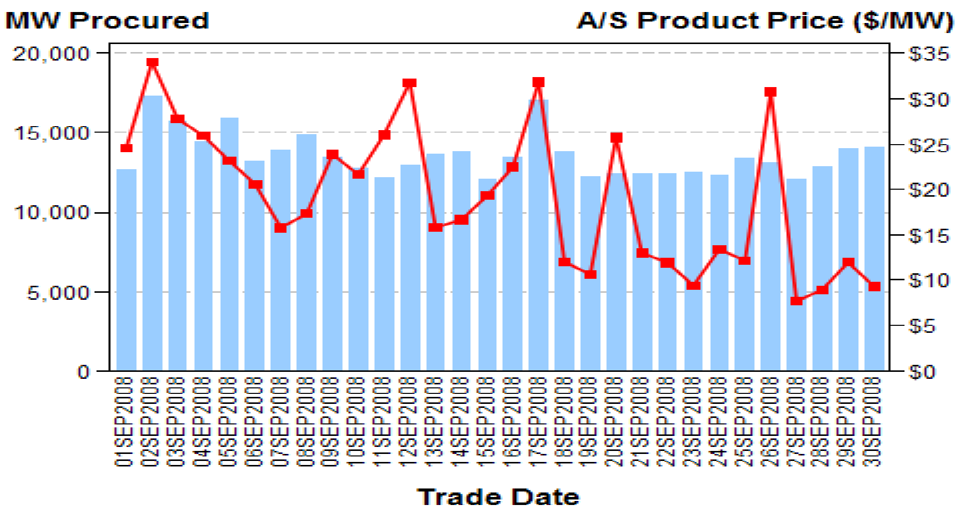


Figure 10. Daily Regulation Down MW Procured and Weighted Average Price

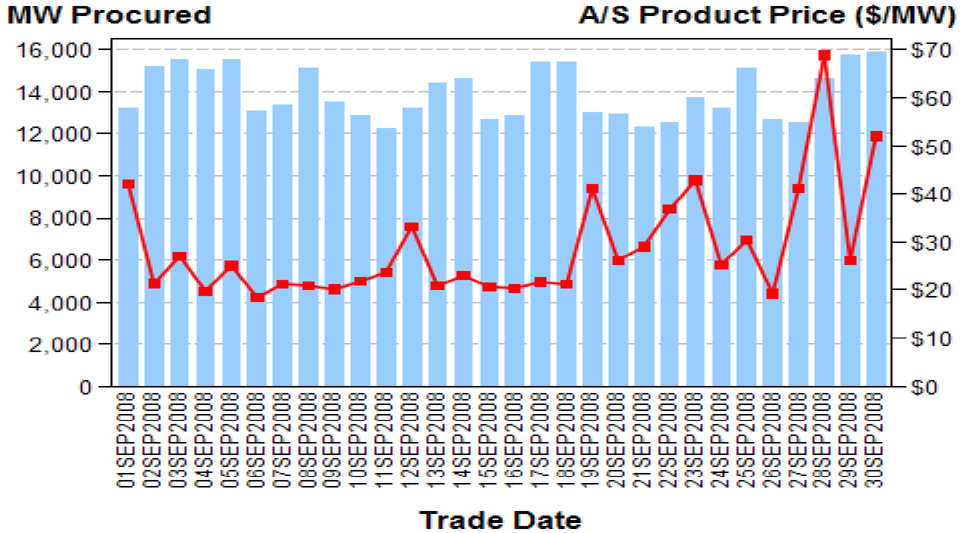


Figure 11. Daily Spinning Reserve MW Procured and Weighted Average Price

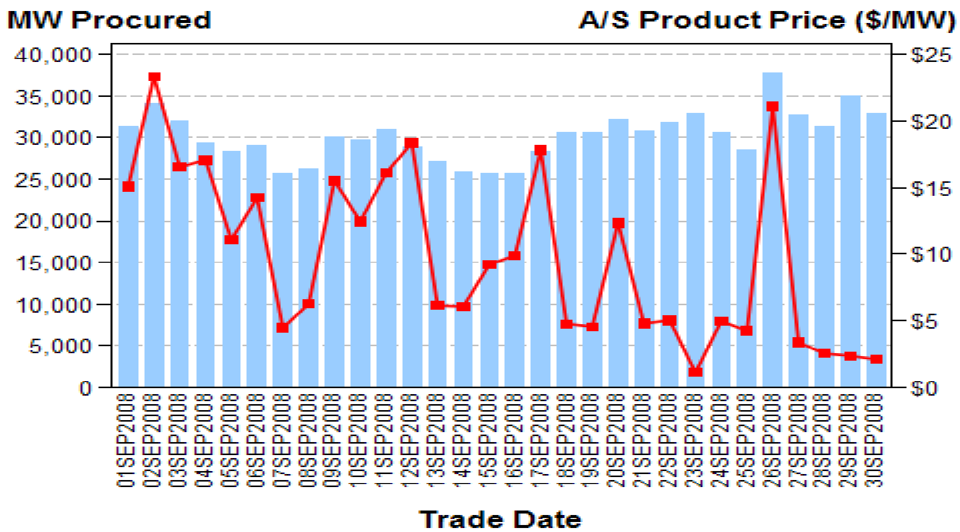
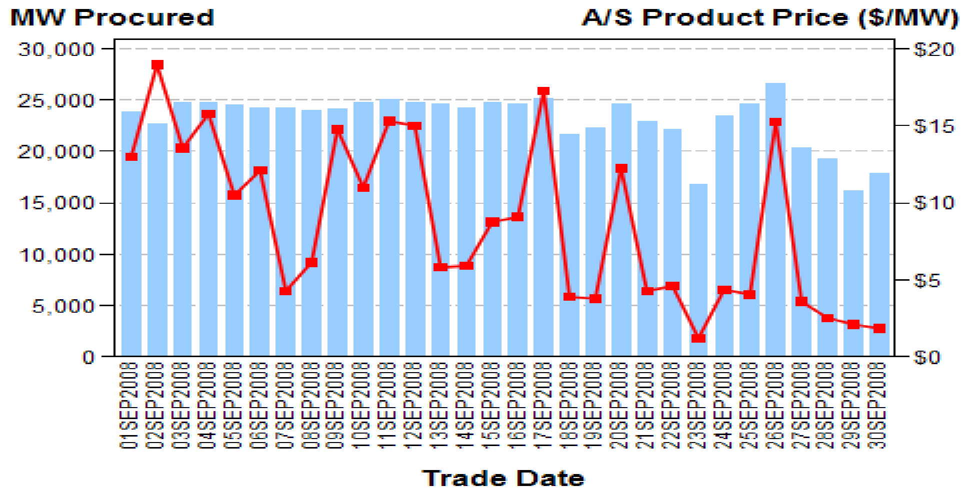


Figure 12. Daily Non-Spinning Reserve MW Procured and Weighted Average Price



Residual unit commitment

Figure 13 shows the daily quantities of RUC capacity procured from non-RA resources and the weighted average price paid to these resources for all hours. The average price paid to non-RA resources awarded RUC capacity was typically in the $40-$80/MW range. However, on several days (September 17, 20, and 27), the average price paid was much higher, at approximately $300-$340/MW – despite a RUC bid cap of $250/MW. Potential explanations for these price excursions include:

- **September 9** – Higher average RUC payments and higher RUC awards are due to the specific scenario that day, which called for increasing the RUC net-short by 20 percent (Scenario 34a)
- **September 17** – Higher average RUC payments appears to be due to the day-ahead market scenario which called for de-rating the Southern California Import Transmission (SCIT) limit to 5,000 MW (Scenario 39). With SCIT derated, imports to southern California were limited and the RUC optimization had to utilize more capacity from internal generation, which in some cases was insufficient and caused extreme RUC prices.
- **September 20 –** Higher average RUC payments are likely due to the scenario modeled for that trade day, which called for having insufficient supply in the day-ahead market by reducing supply by 30 percent (Scenario 10).
- **September 27 –** Higher average RUC payments are likely attributable to the large amount of RUC capacity purchased from non-RA resources (25,000 MW compared with 4,000-5,000 MW in prior days). This unusually high procurement of RUC stemmed from a structured scenario of testing insufficient demand in the day-ahead IFM (Scenario 11) that involved reducing the amount of self-scheduled load in the IFM by 5,000 MW. This resulted in load being under-scheduled in the IFM by approximately 35 percent (Figure 17), which in turn increased demand for RUC capacity.

As evident in Figure 13, the amount of daily RUC capacity awarded to non-RA units (i.e., RUC awards) was typically around 5,000 MW, most of which was procured during the peak hours (Figure 14). When averaged over the 16 peak hours, this translates to approximately 300 MW per hour of non-RA RUC capacity awards. The consistent need to rely on non-RA resources indicates there is insufficient RA capacity being offered to the day-ahead market – at least in particular locations. Currently, the CAISO only publicly provides RUC LMPs on its OASIS. To provide greater transparency on RUC procurement of non-RA capacity, the CAISO should consider posting RUC awards to non-RA resources by Local Capacity Area. With this additional information, LSEs may be able to make modifications to their RA holdings or supply offerings to the day-ahead market to mitigate the reliance on non-RA capacity in RUC.

Figure 13. Daily RUC Awards and Weighted Average RUC LMP (All Hours)

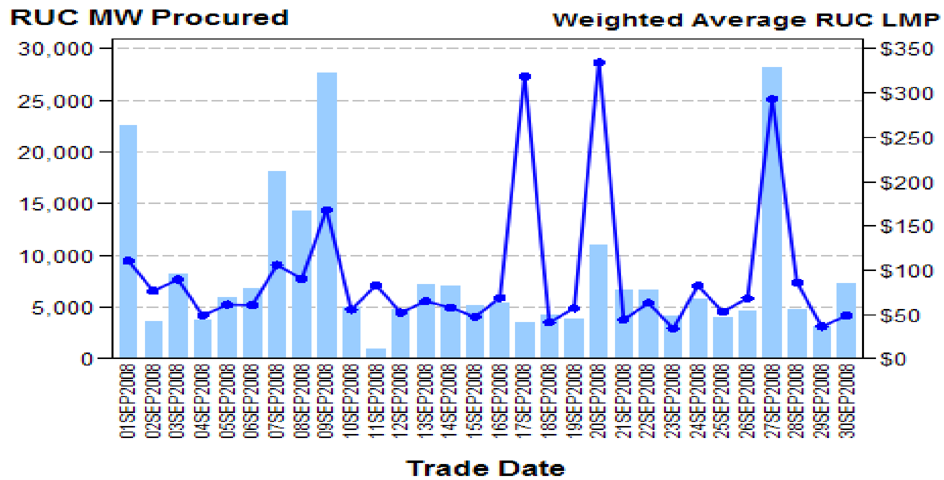


Figure 14. Daily RUC Awards and Weighted Average RUC LMP (Peak Hours)

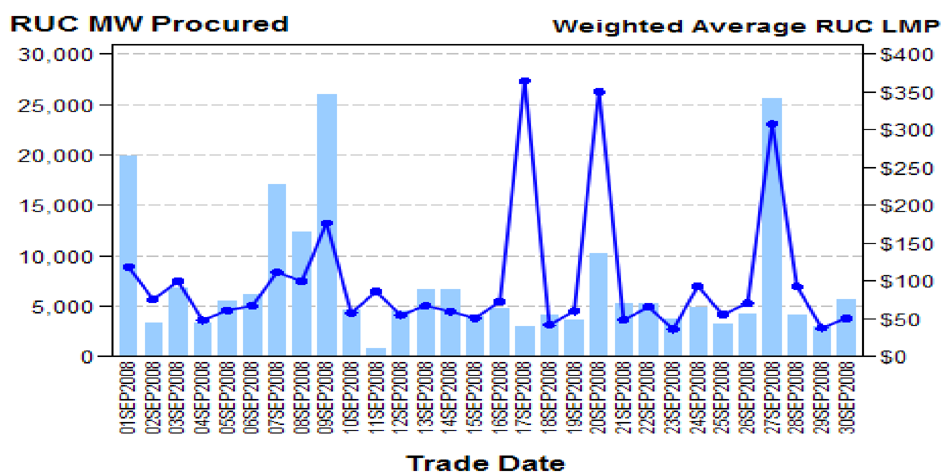


Figure 15 shows a daily breakdown of the portion of RUC capacity (i.e., RUC procurement target) that is met by RA resources versus non-RA (i.e. RUC capacity awards). The line plot in Figure 15 expresses the RUC awards as a percent of the total RUC capacity and indicates that on most days, 10-15% of the total RUC capacity is met by non-RA resources. Importantly, during the September market simulations, the RUC procurement target was biased upwards by roughly 10% to compensate for certain simulation deficiencies in the real-time market that were overstating the real-time demand. Not having this bias in place, may have greatly reduced the reliance of non-RA capacity in RUC.

Figure 15. Daily RUC Capacity from RA and non-RA

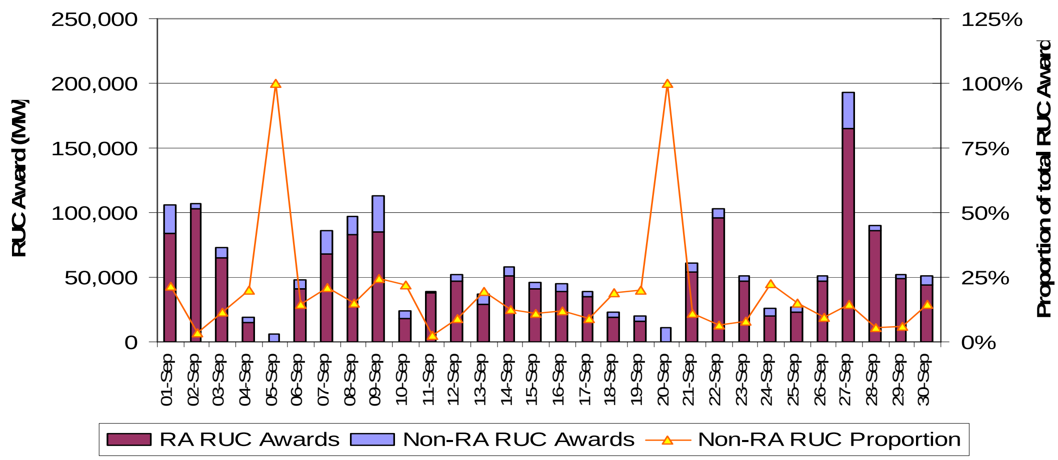


Figure 16 separates the RUC capacity awards for each day into price bins representing the RUC LMP payments received for those awards. Most RUC capacity awards were at RUC prices below $100/MW. However, there were several days of RUC capacity awards at prices well above $100/MW. Most notably, September 9, September 20 and September 27, which as discussed above are trade dates that had specific scenarios designed to stress the RUC market – among other things.

Figure 16. RUC Awards by RUC Price Bins

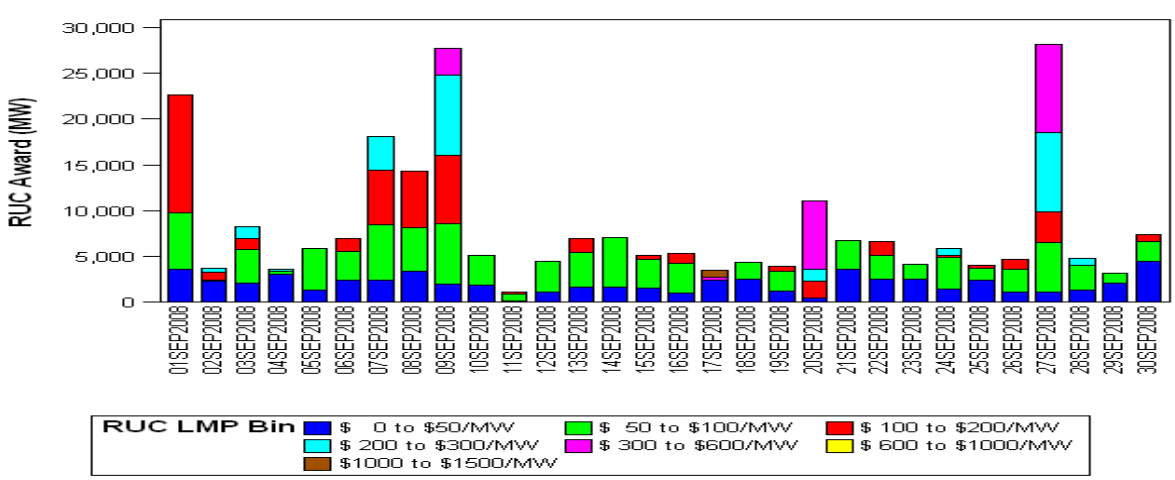
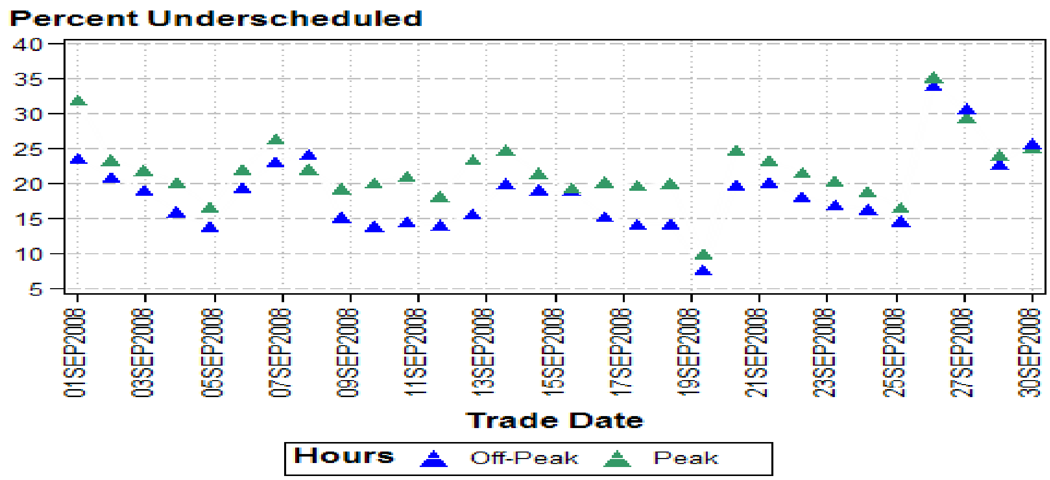


Figure 17. Percent of Load Under-Scheduled in IFM



Congestion

This section highlights the constraints that were most often congested in the day-ahead IFM during the September market simulations. Relatively small transmission facilities (with limits less than 300 MW) are not included in this analysis. Transmission constraints are grouped into four different categories:

- **Inter-ties –** Representing transmission interfaces with other control areas.
- **Lines –** Individual transmission lines within the CAISO control area.
- **Corridors –** Groups of individual transmission lines (typically parallel) that have a collective limit.
- **Nomograms –** Multiple corridors with a simultaneous limit.

The most frequently congested transmission facilities under each of these categories of constraints are shown in Figure 18 to Figure 21 along with the average shadow prices for each constraint. With respect to inter-ties (Figure 18), the North Gila inter-tie (NGILABK4) was the most frequently congested (74 percent of total hours) followed by the Imperial Irrigation District to SCE inter-tie (IID-SCE) at 59 percent of the total hours. These inter-ties are frequently over-scheduled in the market simulation. The Pacific AC inter-tie (PACI) and Palo Verde were also frequently congested (approximately 40 percent of the total hours). No individual lines were consistently congested in the day-ahead IFM (Figure 19). However, one transmission corridor (IPP-IPPGEN) was consistently congested in 72 percent of the total hours (Figure 20) due to self-schedules. Only one nomogram, T-132E Miguel**,** was frequently binding in 32 percent of the total hours (Figure 21)

Figure 18. DA Congestion Frequency of Inter-ties for September 2008

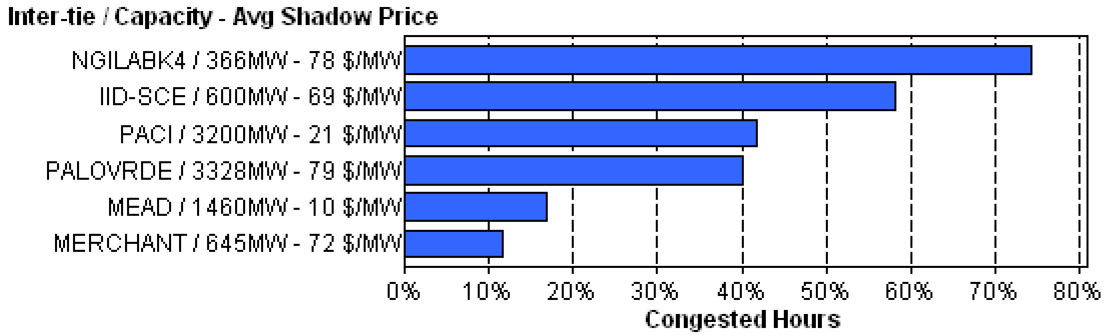


Figure 19. DA Congestion Frequency of Lines for September 2008

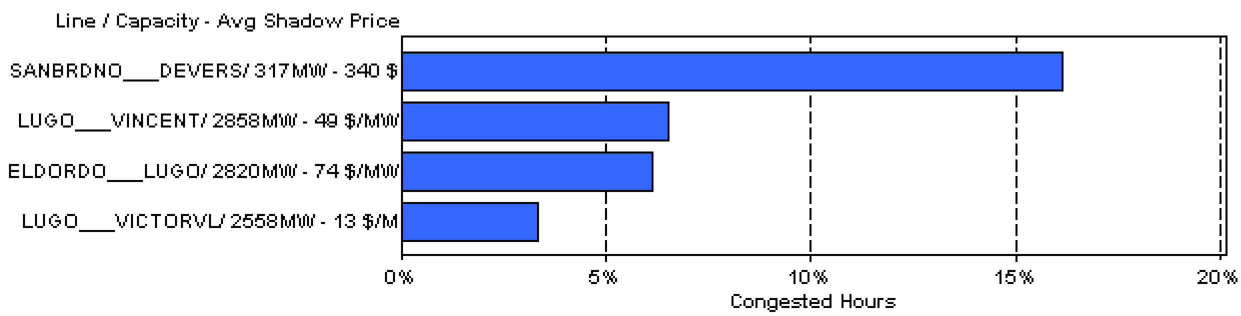


Figure 20. DA Congestion Frequency of Corridors for September 2008

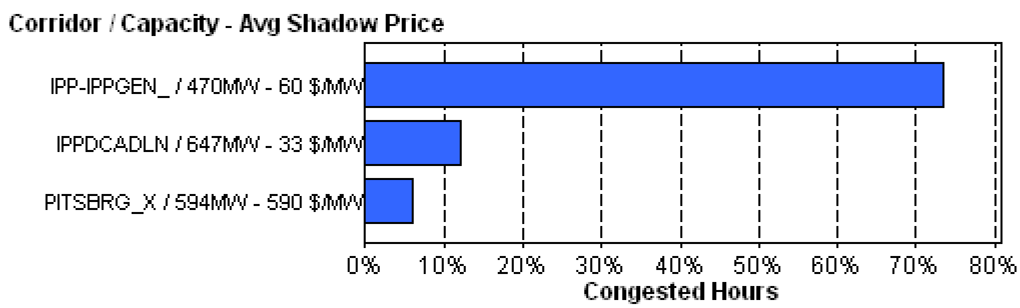


Figure 21. DA Congestion Frequency of Nomograms for September 2008

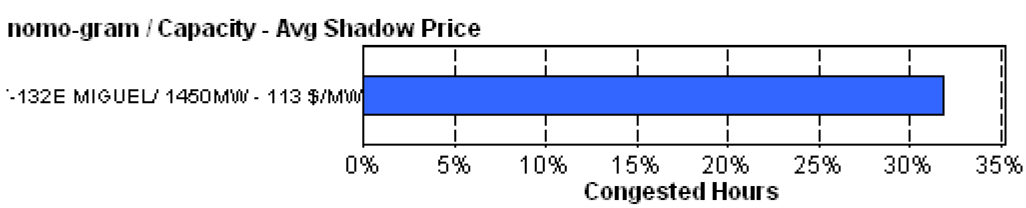


Figure 22 to Figure 25 show the daily congestion frequencies for the frequently congested constraints identified in the previous charts. With respect to inter-ties (Figure 22), North Gila and IID-SCE were consistently congested in most hours of each day in September. Congestion on individual lines (Figure 23) was more episodic with Eldorado to Lugo being congested in six consecutive days (September 12-18) and San Bernardino to Devers congested in the last eight days of September (September 23-30). With regard to congestion on corridors (Figure 24), the IPP-IPPGEN corridor was congested in practically all hours for the first half of September and for sporadic hours in each day of the rest of the month. Figure 25 shows that the Miguel nomogram (T-132E Miguel) was consistently congested in approximately half the total hours of each day throughout September with the exception of September 20-22.

Figure 22. Daily Breakdown of Congestion Frequencies of Inter-ties in the DA Market

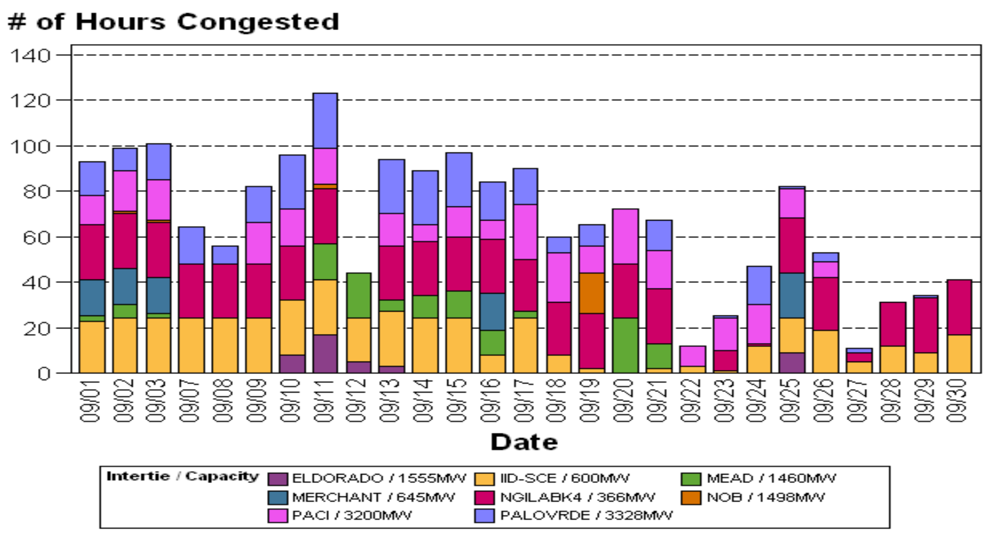


Figure 23. Daily Breakdown of Congestion Frequencies of Lines in the DA Market

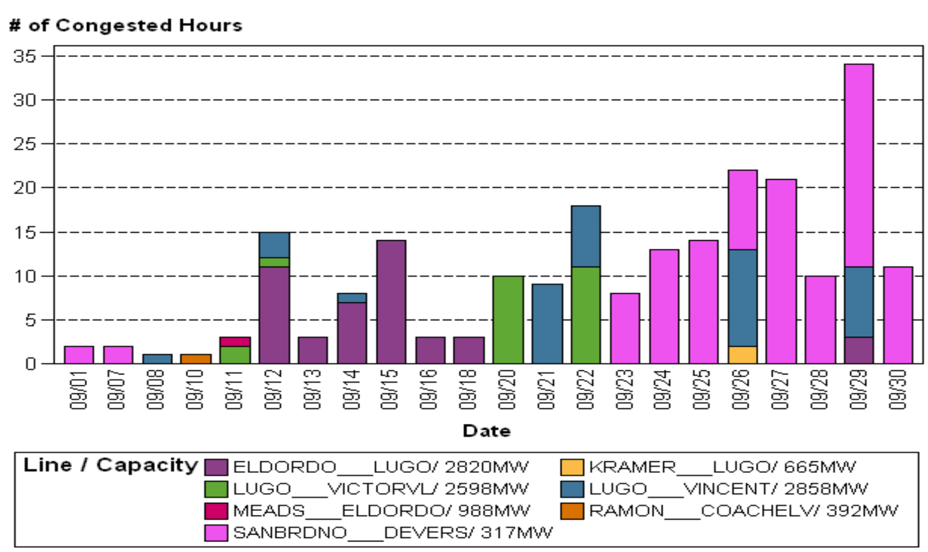


Figure 24. Daily Breakdown of Congestion Frequencies of Corridors in the DA Market

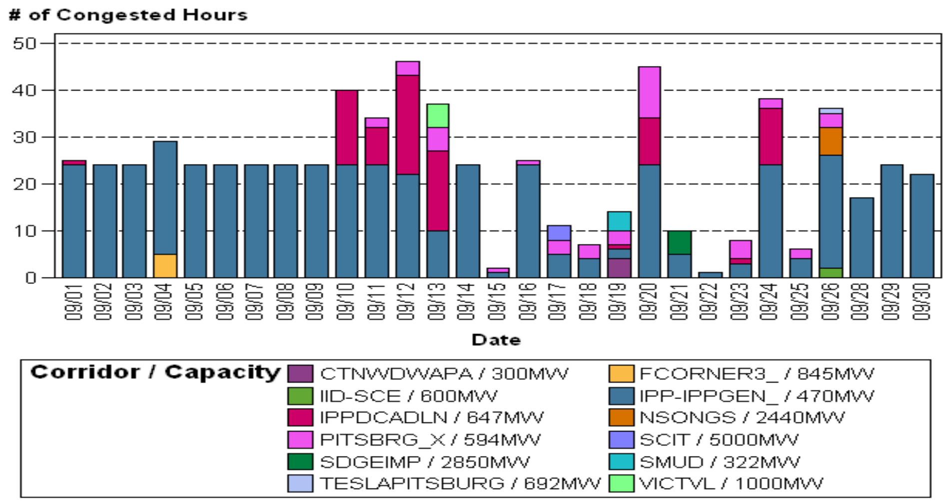
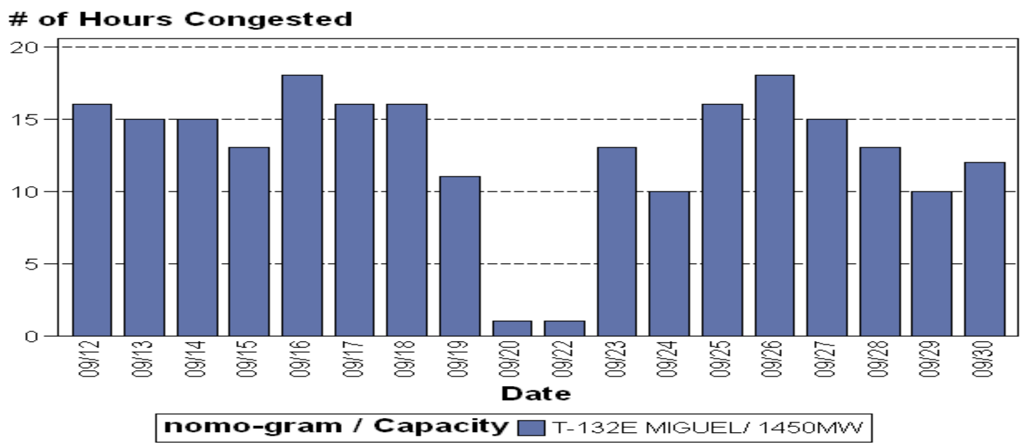


Figure 25. Daily Breakdown of Congestion Frequencies of Nomograms in the DA Market



Real-time market

This section provides an overview of the performance of the real-time market during the month of September. The prices shown here are limited to the 5-minute dispatch market (real-time dispatch or RTD). Market performance in the HASP is reviewed as a special topic in the next section. Unfortunately, there was insufficient time to provide a formal review of the real-time ancillary service market.

This section begins with a review of LAP prices and then provides a review of individual LMP prices. One general observation is that energy prices in the real-time market were significantly higher and more volatile than energy prices in the day-ahead IFM. Two factors that likely caused much of the observed price divergence are 1) the relatively low levels of load clearing the day-ahead IFM (see Figure 17), which increased demand in the real-time market, and 2) the lack of price responsive demand in the real-time market – in contrast to the IFM where demand at the LAP can submit price responsive bids to mitigate against high prices. The second factor also likely contributed to greater price volatility in the real-time market.

Figure 26 shows the daily weighted average LAP prices for the peak hours of the real-time market. Compared to the day-ahead IFM (Figure 1), average LAP prices in the peak hours of the real-time market are generally much higher and exhibit more day-to-day volatility. Of particular note are average peak hour LAP prices for September 17 and September 22.

- **September 17 –** The extreme daily average peak hour LAP prices for this day for SCE and SDGE are likely the result of the scenario executed on that day, which involved under-procuring RUC and increasing the real-time load forecast by 2,000 MW (Scenario 35).
- **September 22 –** All three daily average peak hour LAP prices are in the $500 - $600/MWh range. This day also experienced an unusual number of LMP price spikes (Figure 34). The extreme average peak hour LAP prices observed on this day appear to be related to a problem with incorrect load forecast information being provided to the Real Time Market from the Grid Operator Training Simulator (GOTS).

Figure 26. Daily Weighted Average Real-Time Peak Hour LAP Prices

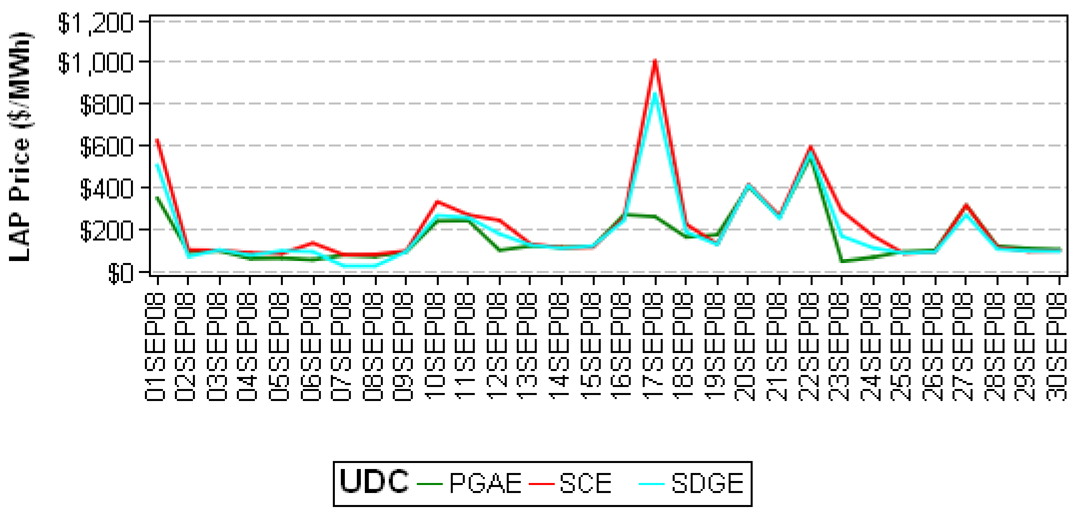


Figure 27 shows the daily weighted average LAP prices for the off-peak hours of the real-time market. Average real-time LAP prices during the off-peak hours are more volatile than the average day-ahead LAP prices (Figure 2) but unlike with the peak hours, the average or median of real-time LAP prices are more in line with off-peak day-ahead LAP prices. Most pronounced in Figure 27 is the extreme negative daily average off-peak LAP prices observed for SDGE on September 12, 15, and 22. These appear to be due to real-time congestion north of the San Onofre Nuclear Generation Station (SONGS), which requires backing down generation in the San Diego region. To the extent there are insufficient decremental supply bids in the San Diego region, generation self-schedules would need to be adjusted and this would likely produce negative LMPs in that region. Congestion north of SONGS was prevalent on these days (see Figure 38).

Figure 27. Daily Weighted Average Real-Time Off-Peak Hour LAP Prices

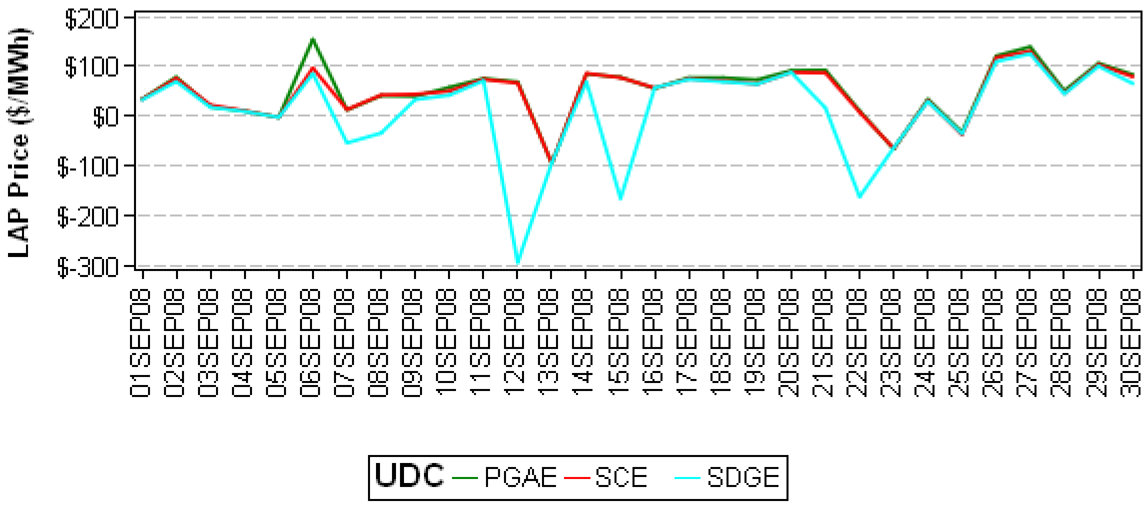


Figure 28 shows a price duration curve for the real-time LAP prices for the entire month of September and Figure 29 shows a blow-up of the right and left tails of this distribution. As evident from these figures, roughly 90 percent of the total real-time LAP prices for September are within the bid cap range of $500 to -$30/MWh. In terms of extreme real-time LAP prices, approximately 2 percent of the real-time LAP prices exceeded $1,000/MWh, and in the other extreme, roughly 2.5 percent of the real-time LAP prices were below -$100/MWh with most of those being the SDGE LAP price.

Figure 28. Duration Curve of Real-Time LAP Prices for September 2008

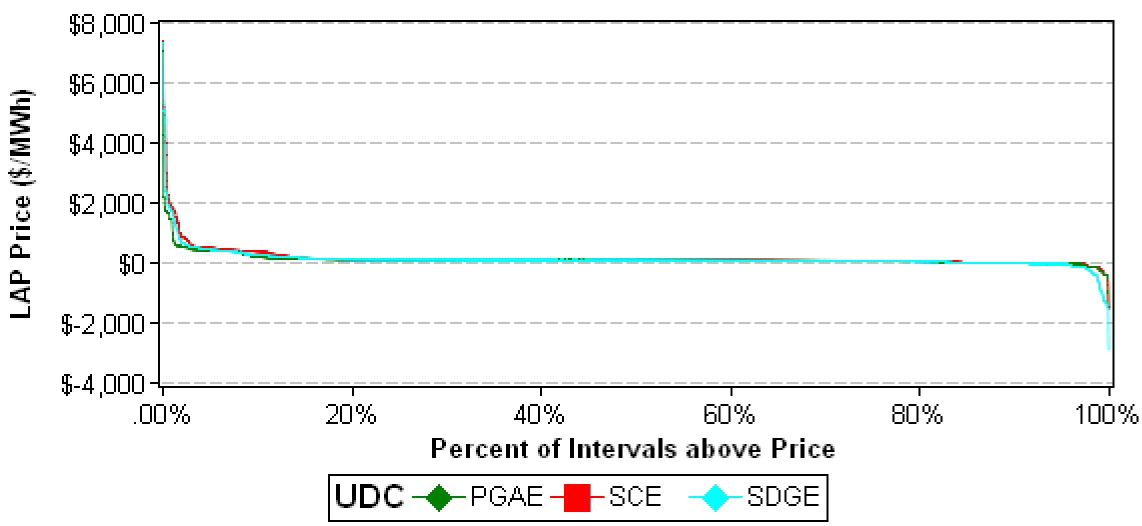


Figure 29. Duration Curve of Upper and Lower 5 percent of Real-Tim LAP Prices for September 2008

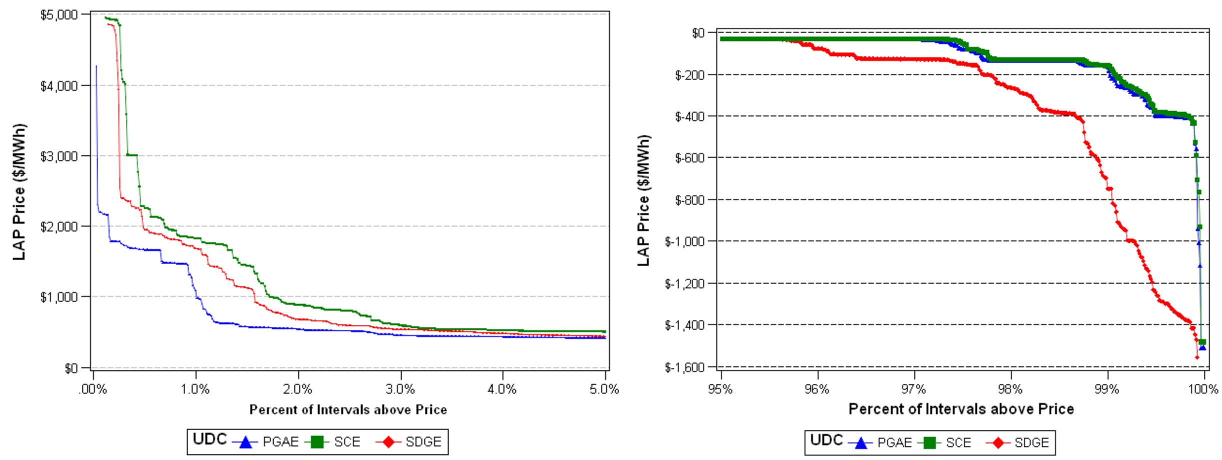


Figure 30 provides a geographic visual of the weighted average real-time LMPs for all peak hours in September. However, as in Figure 5, only about half of the pricing nodes are represented in this figure. The CAISO is currently in the process of adding the missing nodes to this graphic tool. Nonetheless, the figure does provide some indication of the geographical dispersion of LMP levels. In comparing the price dispersion of real-time average LMPs for peak hours to that of the day-ahead (Figure 5), the most striking difference is the consistent pattern of significantly higher average real-time LMPs. Most of Central California (Bakersfield to Sacramento) has average real-time LMPs in peak hours that are within $175-$200/MWh – compared to $75-$100/MWh for the same hours in the day-ahead IFM (Figure 5). Similar to the day-ahead IFM, the peak hour real-time LMPs in the Northern California Humboldt area (west of Redding) are significantly higher. Another significant observation is that average LMPs in Southern California (Los Angeles to San Diego) for the peak hours of the real-time market are significantly higher – in excess of $200/MWh in most locations.

Figure 30. Weighted Average of Real-Time LMPs (September Peak Hours)

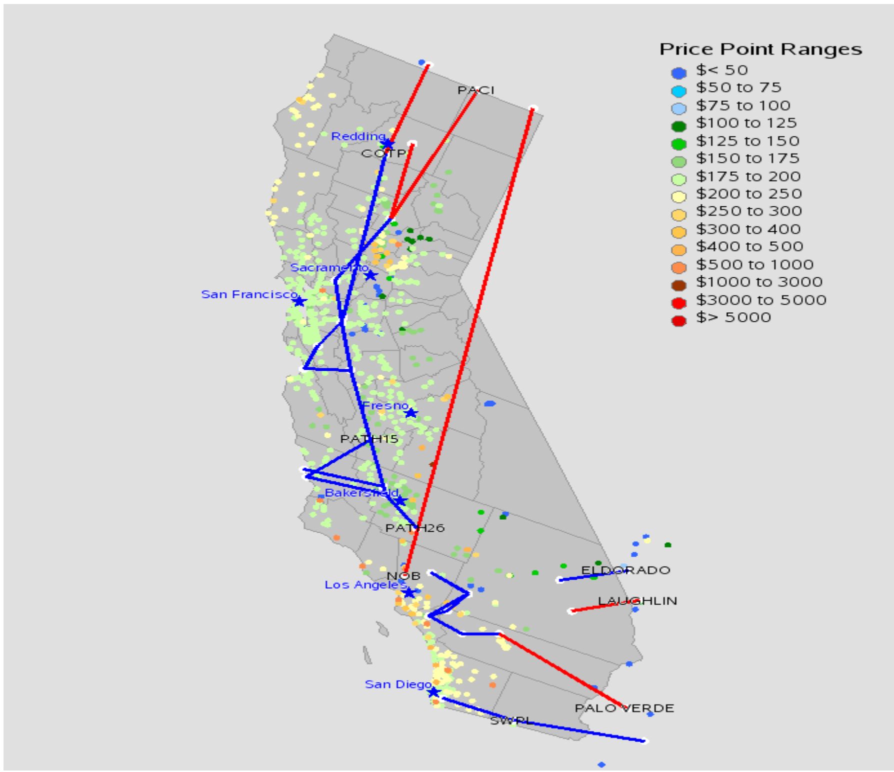


Figure 31 provides a weighted daily average of all real-time LMPs along with 5th and 95th percentile, which provide an indication of the variance (spatially and temporally) of real-time LMPs. The spike in the weighted average price and 95th percentile observed on September 17, as noted above in the discussion of real-time LAP prices, is attributable to the scenario executed on that day, which involved under-procuring RUC and increasing the real-time load forecast by 2,000 MW (Scenario 35).

Figure 31. Weighted Average, 5th Percentile, and 95th Percentile of Real-Time LMPs

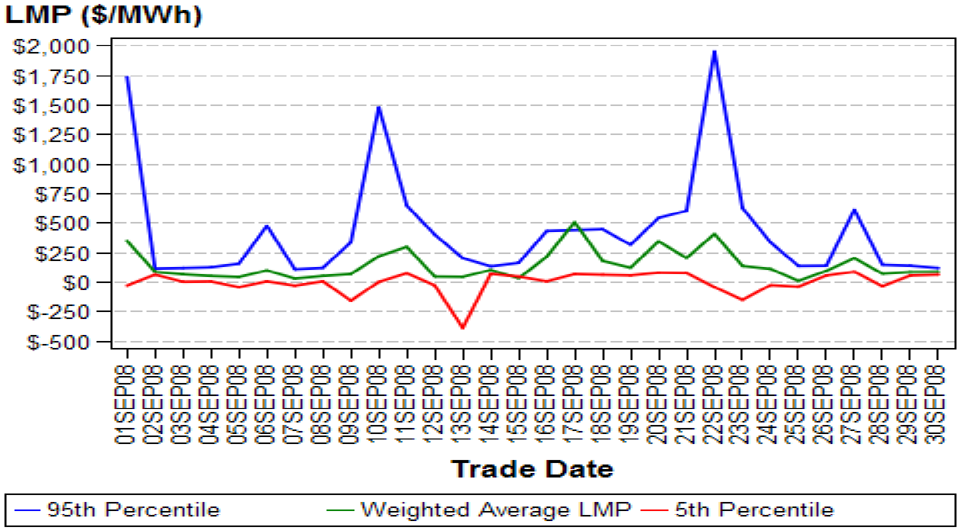


Figure 32 provides a duration curve of all real-time nodal market clearing quantities by clearing LMP, and Figure 33 shows blow-ups of the right and left tails of this distribution. As evident from these two figures, roughly 93 percent of all the real-time market clearing quantities in September cleared at prices in the range of the bid caps (-$30 to $500/MWh). Approximately 5.5 percent of the real-time market quantities cleared at prices exceeding the $500 bid cap with 2.5 percent exceeding $1,000/MWh. At the other extreme, roughly 1.5 percent of the real-time market quantities cleared below the -$30/MWh bid cap with less than 1 percent below -$250/MWh.

Figure 32. Duration Curve of Real-Time Market Clearing Quantities and Prices (LMPs) For September 2008[9]

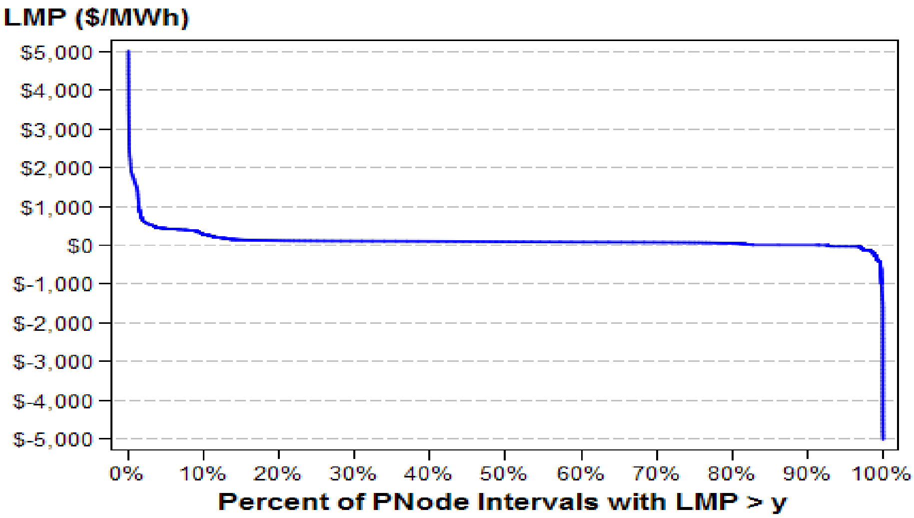
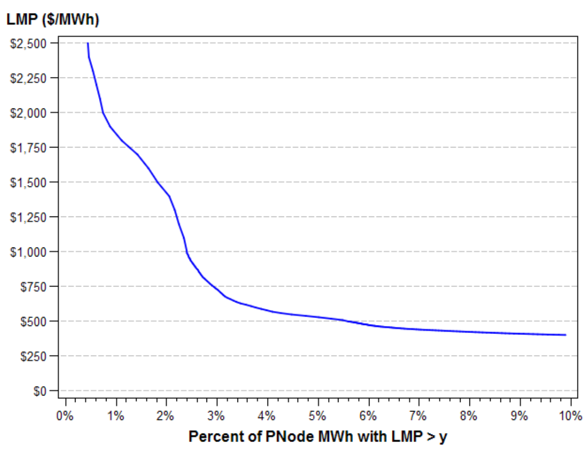


Figure 33. Duration Curve Tails of Real-Time Market Clearing Quantities and Prices (LMPs) For September 2008



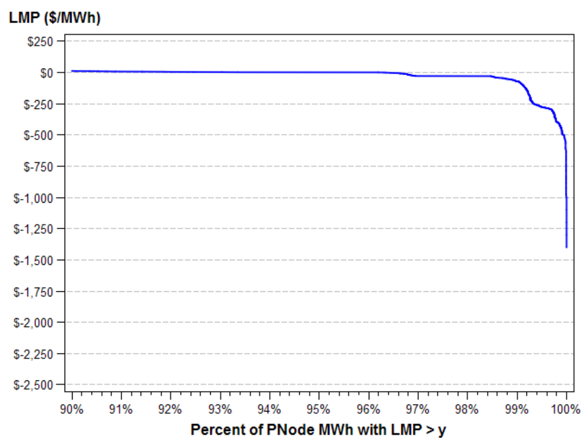
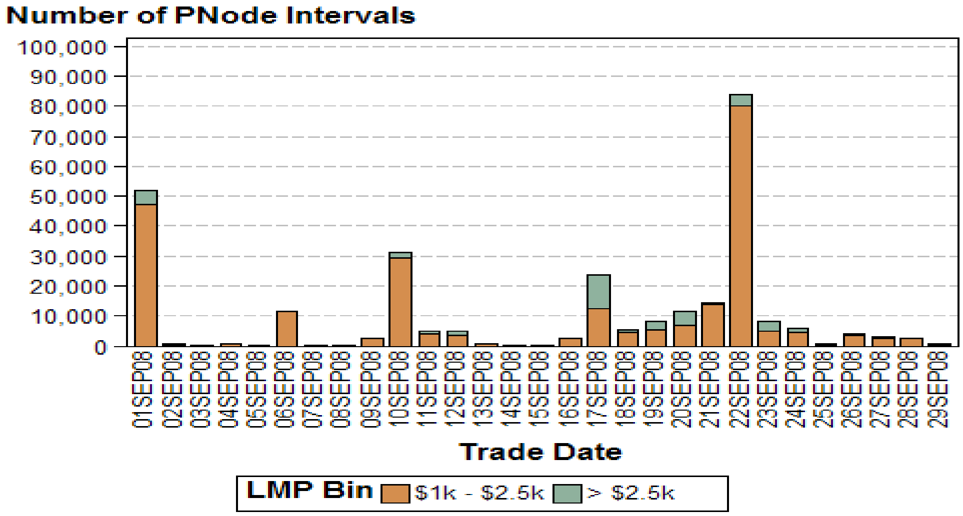


Figure 34 provides a daily count of the number of real-time LMPs that were between $1,000/MWh and $2,500/MWh and that exceeded $2,500/MWh. Interestingly, most of the extreme positive real-time LMPs occurred on two days, September 1 and 22. As previously, noted in the discussion on real-time LAP prices, extreme prices observed on September 22 appear to be related to a problem with the incorrect load forecast information being provided across the peak hours from the Grid Operator Training Simulator (GOTS).

[9] The scale for Figure 32 is truncated at +/- $5,000/MWh. The high and low LMPs observed during this period were roughly $11,900/MWh and -$17,700/MWh respectively.

Figure 34. Daily Count of Extreme Real-Time LMPs



Congestion

This section provides a summary of the congestion observed in the real-time market during September. Since this review is only focused on the real-time 5-minute dispatch market (RTD), HASP inter-tie congestion is not reported here and is instead discussed in the special topics section.

Figure 35 shows the most frequently congested individual lines and the corresponding limits and average shadow prices. The Vincent to Antelope line was congested in approximately 12 percent of the real-time intervals and Eldorado to Lugo was congested in approximately 3 percent of the intervals.

Figure 35. Real-Time Congestion Frequency of Lines For September 2008

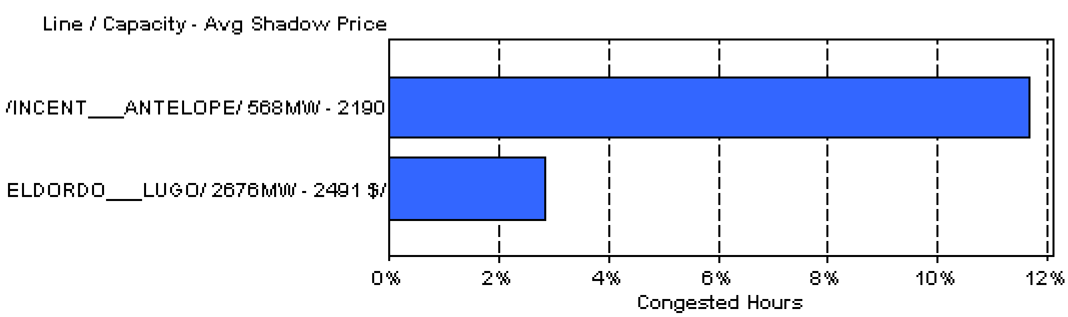


Figure 36 shows the most frequently congested transmission corridors and the corresponding limits and average shadow prices. Similar to the day-ahead IFM (Figure 20), the IPP-IPPGEN corridor was by far the most frequently congested transmission corridor (70 percent of total real-time intervals) with a relatively high average shadow price of $4,929/MW. This was followed by the North of SONGS corridor at 10 percent congestion frequency. The high average shadow price and congestion observed on the IPP-IPPGEN corridor appears to be related to an identified problem relating to rounding final inter-tie schedules in HASP to the nearest whole MW, which when passed on to the real-time dispatch (RTD) market can create residual congestion that produce penalty prices on the impacted inter-ties. To resolve this issue, several patches were installed in late September and October which should largely eliminate congestion on the inter-ties in RTD.

Figure 36. Real-Time Congestion Frequency of Corridors For September 2008

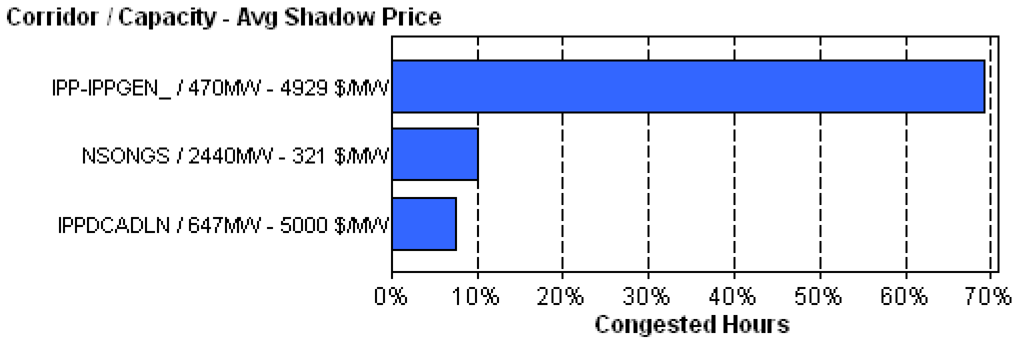


Figure 37 provides a daily breakdown of the congestion frequencies of individual lines in the real-time market. Vincent to Antelope was typically 2-8 hours every day.

Figure 37. Daily Breakdown of Congestion Frequencies of Lines in the Real-Time Market

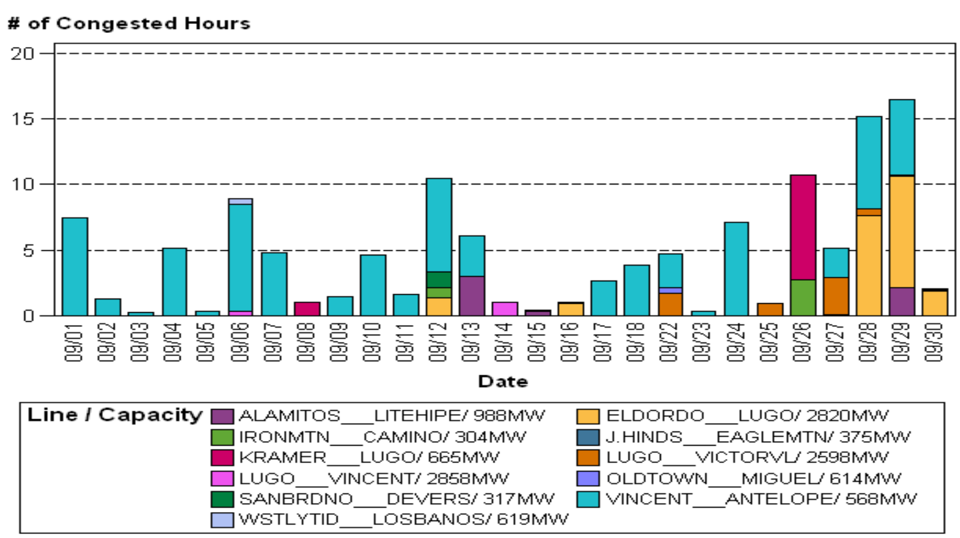
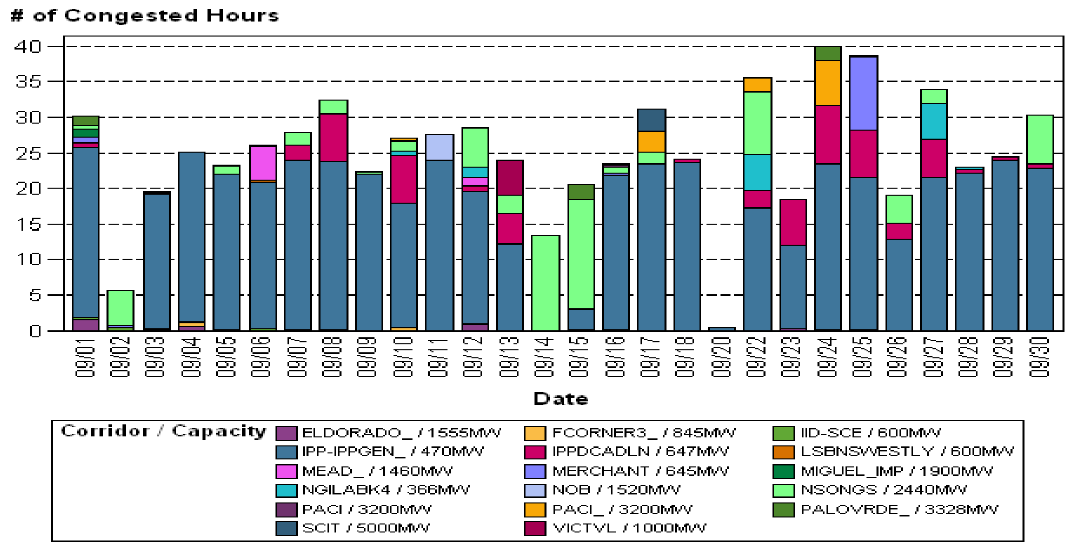


Figure 38 provides a daily breakdown of the real-time congestion frequencies of transmission corridors in the real-time market. The IPP-IPPGEN corridor was congested in most hours of most days in September.

Figure 38. Daily Breakdown of Congestion Frequencies of Corridors in the Real-Time Market



III. Specific Market Issues

This section provides a review of four specific issues that DMM has paid particular attention to during the market simulations.

1) Local market power mitigation
2) Ramp rates
3) Use-limited unit status
4) Divergence of IFM and HASP prices

An assessment of each of these topics is provided below.

Local market power mitigation

Overview

The MRTU market design relies upon a variety of LMPM provisions that are designed to work together to effectively mitigate local market power. 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.

Our review activities to date indicate that the LMPM features of the MRTU software are mechanically functioning as intended, except in cases when the entire market power mitigation (MPM) run fails and/or is skipped in the real-time market (RTM). Our review of data on RTM performance suggests that this may be occurring in up to 5 percent of hours.

In addition to verifying that LMPM is mechanically functioning as intended, DMM will also be performing additional analysis to verify that LMPM will effectively mitigate potential local market power. DMM believes that market simulation results to date provide a relatively limited basis to make this type of assessment due to the relatively low bid prices being submitted in market simulation. To date, we have performed some “stress testing” of LMPM features of the IFM software by raising bid prices of resources needed to meet non-competitive constraints and then re-running the market simulation. Under such scenarios, we have found that local market power can be effectively mitigated. However, we plan to perform additional analysis based on a wider range of bidding scenarios and conditions.

Implementation of LMPM

In order to ensure that LMPM is correctly implemented, DMM is verifying the following key steps of the LMPM process:

- Incorporation of Competitive Path Assessment (CPA) in MRTU model
- Execution of market power mitigation runs
- Application of bid mitigation for units dispatched to meet uncompetitive constraints

Competitive Path Assessment

The first step in applying the LMPM provisions of the MRTU market design is to designate constraints within the CAISO system as either *competitive* or *non-competitive*. All internal constraints are initially considered *non-competitive*, except for the two major existing internal zonal interfaces (Path 15 and Path 26), and any other internal paths that are found to be competitive through application of the Competitive Path Assessment methodology.[10] . The MRTU software models internal transmission constraints in three different ways:

- **Lines** representing individual transmission lines (or internal tie points) with flow limits
- **Corridors** representing groups of transmission lines with a combined flow limit (similar to branch groups currently used by the CAISO in congestion management)
- **Nomograms** representing multiple corridors with a simultaneous limit

Appendix B shows the transmission facilities that would be designated as *competitive* in MRTU based on the most recent CPA completed by DMM in December 2007. DMM will update the CPA prior to MRTU go-live. However, in order to ensure that market simulation results reflect actual LMPM provisions as closely as possible, DMM requested that the most recent CPA results be incorporated into market simulation. As summarized in Table 1 and described below, the CAISO has periodically modified how internal transmission constraints are designated in the market power mitigation runs, with the most recent CPA results being gradually phased in:

- Prior to October 2, all internal constraints modeled as flowgates (including individual lines or tie points and corridors) were designated as *non-competitive* (except for Path 15 and 26).
- On October 2, flowgates that were determined to be *competitive* through the CPA methodology were set to be *competitive*.
- Prior to Sept 8, some nomograms that were <u>not</u> found to be *competitive* through the CPA studies were modeled as competitive in the market simulations (i.e., by including these nomograms in the network model used to perform both the competitive constraint (CC) and all constraints (AC) MPM runs). This contributed to numerous price spikes in market simulation results, since units needed to meet these constraints were not subject to LMPM.
- On September 8, all nomograms in the MRTU model were switched to be *non-competitive* – including constraints found to be competitive in DMM's most recent CPA study. Thus, market simulation results after this date may not provide a completely accurate indication of LMPM performance.
- The CAISO has indicated that nomograms that were found to be competitive in DMM's most recent CPA studies will be represented as competitive in the MRTU software during market simulation, but as of October 15 these changes had not been incorporated but are expected to be added soon.

[10] The methodology and results of the most recent CPA performed by DMM in December 2007 are provided on the CAISO website: *http://www.caiso.com/1cb9/1cb98f565d9c0.pdf*

Table 1. Timeline of Candidate Path Designations in Market Simulation

	25-Aug	1-Sep	8-Sep	15-Sep	22-Sep	29-Sep	6-Oct	13-Oct	20-Oct
Lines	Non-Competitive-->CPA Designation ----------->								
Corridors	Non-Competitive -->CPA Designation ----------->								
Nomograms	Competitive ->		All Set to Non-Competitive -->						

As previously noted, DMM will update the CPA prior to MRTU go live. The major reason for any changes in path designations resulting from an updated CPA would be a change in ownership and/or operational control of generating units. DMM surveys participants prior to conducting an updated CPA in order to determine changes in ownership and/or operational control of generating units. During the first 12 months of MRTU, we may again update the CPA if we determine that system conditions or ownership/control of generating units has changed substantially from the assumptions used in the previous CPA.

<u>Execution of pre-market market power mitigation Runs</u>

Under MRTU, the determination of whether bids for individual units are subject to mitigation is made through a series of market power mitigation software runs prior to the IFM and real-time markets.[11] Thus, one of the key indicators of MRTU software performance being monitored by DMM during market simulation is the frequency with which these pre-market runs are successfully completed.

- **Day-ahead IFM –** Since September 1, the pre-market MPM runs have always been successfully completed in the IFM. On some days, MPM runs have initially failed, with most of these failures being attributed to the software's failure to reach a solution within the allotted number of iterations or level of precision. However, Market Operations logs indicate that in each of these cases the MPM runs were completed with minor relaxations to the software parameters or inputs.
- **Real-time market –** MPM runs for the real-time market are made once per hour during the HASP run. Due to the more limited amount of time available for this real-time process, available data indicate that MPM runs have failed and been skipped in the RTM market simulation as much as about 5 percent of hours since September 1[12], as shown in Figure 39. Such failures are generally caused when the software fails to reach a solution in the required amount of time. Specific *root causes* for the failure to reach a solution

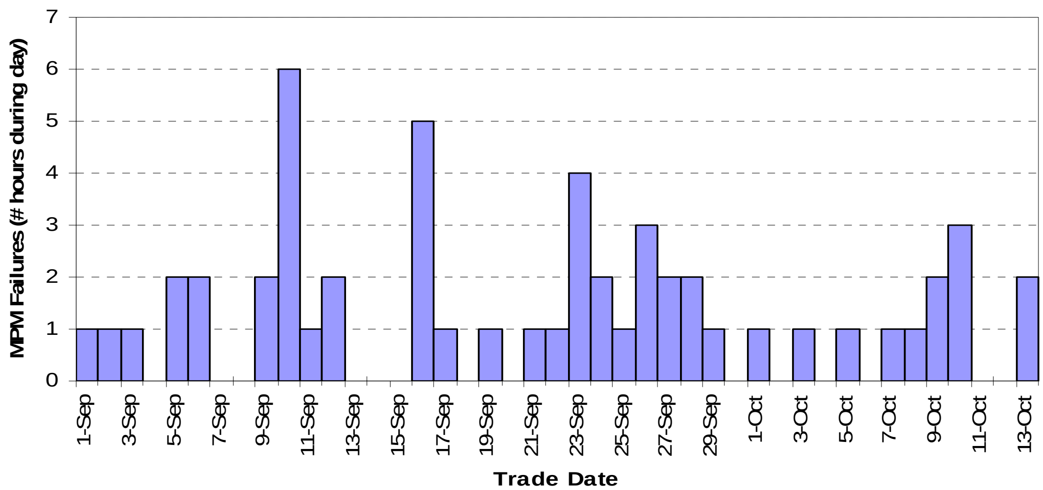
[11] First, a competitive constraint (CC) run is made in which the CAISO's forecasted demand is cleared against market bids with only *competitive* constraints enforced. Then, an all constraint (AC) run is made with *all constraints* enforced. If a unit's dispatch level in this second AC run is <u>highe</u>r than its dispatch level in the first CC run, the unit's market bids are subject to bid price mitigation.

[12] It should be noted that this assessment may be over-stating the frequency of LMPM failures as the data use for it did 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.

typically relate to resource infeasibilities – including infeasibilities relating to Forbidden Regions.

DMM will continue to monitor the frequency of any failures of RTM market power mitigation runs during market simulation, and has recommended that these failures be formally tracked by the CAISO as a basic market performance metric. In addition, DMM has recommended that the CAISO establish pricing provisions that may be applied if the pre-market MPM run is periodically not completed in the RTM in actual market operation.

Figure 39. Potential Frequency of Market Power Mitigation Run Failures in Real-Time Market



DMM has also performed some stress testing of the MPM features of the IFM software by re-running market simulation data after raising bid prices of resources needed to meet non-competitive constraints (i.e., simulating relatively extreme cases of economic withholding in the IFM). Under such scenarios, DMM has found that the MPM run may fail to reach a solution that meets the required level of precision (or MIP Gap) unless the solution time is increased. DMM does not yet have the capability to perform such stress testing of the MPM features of the RTM. Because of the decreased amount of time available to run MPM in the RTM, it may be more difficult to avoid MPM failures in the RTM by increasing the solution time.

Application of bid mitigation

Under MRTU, units that are identified in pre-market MPM runs as being needed to relieve congestion on *non-competitive* constraints are subject to bid mitigation. Thus, DMM has also developed procedures to monitor and spot check that rules for bid mitigation are being correctly applied during market simulation. These include the following:

- **Identifying units subject to bid mitigation.** Each unit that is dispatched in the pre-market AC run at a higher level than in the CC run are subject to bid price mitigation (i.e., may have their market bids adjusted, depending on the rules for bid mitigation, as described below).

- **Confirming application of bid mitigation rules.** When units are subject to bid price mitigation, rather than simply replacing the unit's market bid with the DEB, the MRTU software may lower the unit's market bid pursuant to a series of rules for combining market bids with the unit's DEB.[13]
- **Reviewing default energy bids used in bid mitigation.** DEBs used in performing bid mitigation must be accurately calculated based on the various options selected by the unit owner.[14] Under MRTU, DEBs will be calculated by an independent entity (Potomac Economics). Although the Market Services Department will have primary responsibility for validating the accuracy of DEBs provided by Potomac on an ongoing basis, DMM is also providing an independent review and spot checking of DEBs prior to and after MRTU go-live.

Our review of market simulation results to date indicates that when pre-market MPM runs are made, these elements of the MRTU software are correctly functioning. However, it should be noted that DEBs used in market simulation do not correspond to DEBs that would actually be used under MRTU for a variety of reasons.

- Although the LMP-based DEB option will not be in effect until 90-days after MRTU go-live, the CAISO and Potomac have set the LMP-based option as the primary DEB option for all resources in order to test this feature of the DEB software.
- Cost-based DEBs – which are used when the number of times a unit has been scheduled or dispatched is insufficient to calculate an LMP-based DEB – are based on a fixed gas price of over $10/MMBtu. This results in cost-based DEBs that are often relatively high compared to market bids submitted by participants.
- In some cases, units have not yet submitted the data necessary to calculate cost-based DEBs, which are used when there is insufficient data to calculate an LMP-based DEB. This has resulted in some extremely low DEBs, which reflect only the default variable operation and maintenance (O&M) component of the cost-based DEBs (e.g., $4/MWh).

Effectiveness of LMPM

In addition, we are also reviewing the effectiveness of LMPM using a variety of approaches, including:

- Reviewing market simulation results
- Examining special bidding scenarios using a version of the MRTU software known as the DMM standalone environment.
- Reviewing and monitoring DEBs, including DEBs developed under the consultative DEB option

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[13] For example, a unit's highest accepted bid in the CC run represents a floor, below which no portion of the unit's final modified bid may be mitigated. Otherwise, the unit's final mitigated bid is based the lower of a unit's DEB or market bid.

[14] Initially, DEBs will be either cost-based or negotiated. However, starting 90 days after MRTU go-live, DEBs may be based on the LMP-based option, subject to minimum requirements on the amount of time intervals during which the unit was dispatched and not subject to mitigation.

- Review of start-up and minimum load cost data, including units selecting the registered cost option
- Reviewing and monitoring 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
  - Start-up times, minimum run times, etc.
  - Requests for treatment as a use-limited resource

DMM's initial analysis of two of these issues (ramp rates and limited energy units) is summarized later in this report.

As noted above, one of the mechanisms we use to assess the effectiveness of LMPM under MRTU is to examine special bidding scenarios using a version of the MRTU software known as the DMM standalone environment. This standalone environment is used to assess the general effectiveness of LMPM measures in several ways:

- **Competitive baseline analysis**. DMM uses the standalone environment to calculate a competitive baseline scenario under which LMPs are calculated by re-running the IFM with (1) market bids for all gas-fired units replaced with cost-based DEBs, and (2) price-taking demand bids set equal to actual demand. Results of this analysis are compared to actual market results at various levels of aggregation to assess various specific areas in which LMPM may be less effective (e.g., LAP, LCR and sub-LCR areas).[15]
- **Special analysis of supplier bidding strategies**. The standalone environment is also used to perform *ad hoc* analysis of specific factors that may undermine the effectiveness of LMPM based on other monitoring metrics (e.g., bid-cost markups, economic withholding by individual units and suppliers, etc.). As part of our review of market simulation, we have also performed some stress testing of the MPM features of the IFM software by re-running market simulation after raising bid prices of a significant portion of resources needed to meet non-competitive constraints to reflect relatively extreme cases of economic withholding in the IFM. Under such scenarios, we have found that the LMPM provisions of the IFM software effectively limit prices within major transmission constrained areas even under hypothetical scenarios in which a significant portion of capacity was bid at extremely high prices.

Ramp rates

MRTU was designed to allow generators the flexibility to submit ramp rates with their energy bids that are lower than the unit's maximum ramp rate registered in the CAISO Master File. However, submission of relatively low energy bid ramp rates (below the actual feasible ramp

[15] Several other variations of the competitive baseline analysis will also be routinely run using the DMM standalone environment. For example, the impact of *load under-scheduling* will also be assessed by running the IFM with price-taking demand bids set equal to actual demand, but without modifying supply bids. Results of this scenario could then be compared to actual market results and the competitive baseline scenario to assess the impact of strategic bidding by demand.

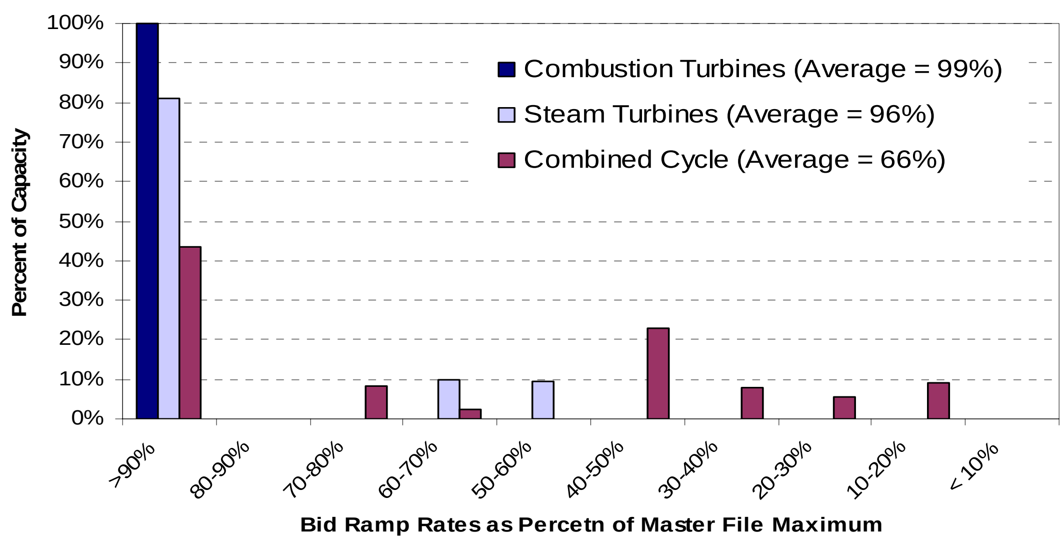
rate of a unit) could cause market inefficiencies and could have the effect of withholding capacity in the CAISO markets.

To address this potential issue, DMM will monitor ramp rates submitted by generating units and assess the potential market impacts of relatively low ramp rates submitted by individual units and/or by groups of units. Figure 40 illustrates some initial analysis of IFM energy bid ramp rates submitted by gas-fired units in market simulation during early October.[16] As shown in Figure 40:

- Ramp rates being submitted in the IFM by combustion turbines have been relatively high, equaling about 99 percent of maximum ramp rates registered in the Master File.
- Ramp rates being submitted in the IFM by steam turbines also have been relatively high, equaling about 96 percent of maximum ramp rates registered in the Master File.
- However, ramp rates submitted by combined cycle units have average only about 66 percent of maximum ramp rates registered in the Master File, with nearly half of combined cycle capacity being bid with ramp rates less than 50 percent of maximum Master File values.

The tendency for combined cycle units to submit lower ramp rates is likely due to concern by combined cycle operators about the somewhat simplified manner in which combined cycle operating constraints are modeled in the MRTU software.

Figure 40. Comparison of Energy Bid Ramp Rates with Maximum Ramp Rates in Master File (Gas Units Only)



[16] Units which are scheduled in the IFM cannot modify their energy bid ramp rates in the real time market, except through a SLIC de-rate. Consequently, our initial analysis has focused on ramp rates submitted for IFM energy bids.

Use-limited unit status

Gas-fired thermal units under resource adequacy contracts are subject to an all-hours must-offer obligation, unless they request and receive approval for treatment as use-limited resources.[17]

- Currently, units representing just over 1,000 MW of gas-fired capacity have requested and been approved for limited energy treatment under MRTU.[18]
- Virtually all of this capacity has been approved for use-limited status due to environmental permitting constraints, such as limits on start-ups and run hours.

However, over 3,000 MW of gas-fired capacity is currently designated in the CAISO Master File as use-limited. The CAISO has indicated that designation of use-limited resources will be corrected in the next version of the Master File.

Divergence of IFM and HASP prices

As noted in previous sections of this report, 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 during some periods, particularly during off-peak hours. This divergence is part of a more general trend of higher overall prices in the real-time market compared to the IFM during some periods.

The tendency for HASP prices to exceed IFM prices is illustrated in Figure 41, which shows the difference in HASP and IFM LMPs for the Malin tie point during peak and off-peak hours. Positive values in Figure 41 indicate days when the average prices in the HASP exceeded the average price in the IFM for the Malin tie point. As shown in Figure 41, since mid-September HASP prices resulting from market simulation have tended to be systematically higher than IFM prices on Malin, with the overall average price differential between the HASP and IFM prices being driven up by periods of much higher prices in the HASP.

Table 2 provides a more detailed summary of price trends in market simulation results for the IFM and HASP from September 1 through October 10.

- Columns A through D show the average scheduled quantities and LMPs for various tie points in the IFM and HASP. Columns E and F show the average difference in HASP and IFM schedules and LMPs, respectively, for each tie point.[19] For example, over this time period, prices on the Malin tie point during peak hours averaged $59/MWh in the IFM, compared to an average of $140/MWh in the HASP, representing an average difference of $81/MWh.
- The final three columns of Table 2 show the *percentage of hours* when HASP prices were either (a) at least $5 less than IFM prices, (b) within ± $5 of the IFM LMP, and (c) more than $5 greater than the IFM LMP. For example, during off-peak hours over this

[17] RA units under Limited Energy status units are required to submit Use Plans to the CAISO, describing how the units will bid and operate units to mange energy or other operational limitations.

[18] Excludes has-fired cogeneration capacity.

[19] The incremental change between the quantity scheduled in the IFM and HASP represents the net volume actually settled at the HASP prices.

time period, HASP prices on the Malin tie point were more than $5 higher than IFM prices about 85 percent of hours.

Under MRTU, participants would be expected to change their scheduling and bidding behavior if such significant and systematic price divergences for imports and exports persisted. For example, demand may increase in the IFM and additional supply may be offered in the HASP – both of which would tend to reduce price differences between the HASP and IFM. However, such price differences could also create an incentive for "implicit virtual bidding" at the inter-ties (i.e., submission of IFM bids and schedules that participants may not intend or be able to deliver or receive, but which they intend or expect to buy or sell back in the HASP in order to take advantage of price differences in these two markets). Such "virtual bidding" is not allowed under the initial MRTU market design, and is scheduled to be introduced – with appropriate rules and restrictions – 12 months after MRTU go-live.

Figure 41. Difference in HASP and IFM LMPs - Malin

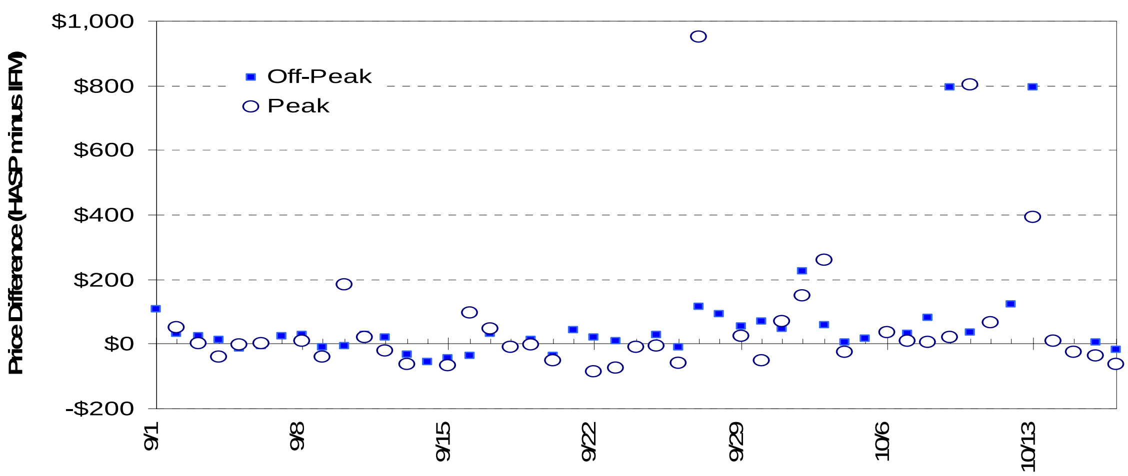


Table 2. Differences in IFM and HASP Prices and Quantities (Market Simulation, Sept 1-October 10)

		IFM		HASP		Difference Between HASP and LMP				
								Percent of Hours		
PNode	Period	Avg. MW [A]	Avg. LMP [B]	Avg. MW [C]	Avg. LMP [D]	Avg MW [C – A]	Avg. LMP [D – B]	HASP > $5 Lower than IFM	HASP +/- $5 of IFM	HASP > $5 Higher than IFM
MALIN_5_N101	Peak	2,507	$59	2,587	$140	80	$81	36%	14%	50%
	Off-Peak	1,912	$36	2,095	$99	184	$64	8%	7%	85%
PALOVRDE_ASR-APND	Peak	2,297	$11	2,030	$67	-267	$56	37%	9%	54%
	Off-Peak	2,038	$12	1,982	$53	-56	$41	23%	10%	67%
SYLMARDC_2_N501	Peak	871	$58	955	$223	84	$165	2%	4%	94%
	Off-Peak	475	$34	538	$116	63	$82	5%	3%	92%
MEADS_2_N101	Peak	521	$52	530	$149	8	$97	17%	9%	74%
	Off-Peak	462	$28	530	$106	68	$78	6%	6%	89%
MCCULLGH_5_N101	Peak	569	$59	622	$156	53	$98	13%	6%	81%
	Off-Peak	454	$29	492	$105	38	$76	6%	4%	90%
FOURCORN_3_N501	Peak	396	$53	430	$129	35	$76	17%	8%	75%
	Off-Peak	110	$28	186	$101	75	$73	6%	4%	89%
MERCHANT_2_N101	Peak	356	$37	349	$107	-7	$69	28%	6%	65%
	Off-Peak	284	$23	284	$97	0	$74	10%	6%	83%
MARKETPL_5_N501	Peak	269	$58	307	$151	38	$92	15%	7%	78%
	Off-Peak	117	$29	139	$105	22	$76	6%	4%	90%
VICTORVL_5_N101	Peak	192	$60	293	$175	102	$116	14%	7%	80%
	Off-Peak	132	$30	228	$106	96	$76	6%	4%	90%
NGILA1_5_N001	Peak	179	-$22	106	-$110	-73	-$88	30%	54%	17%
	Off-Peak	167	-$45	123	-$60	-44	-$15	27%	39%	34%
BLYTHE_1_N101	Peak	89	$29	93	$64	4	$35	23%	3%	75%
	Off-Peak	64	$37	77	$131	13	$94	11%	6%	83%
MEADN_2_N501	Peak	39	$57	51	$151	12	$94	16%	6%	78%
	Off-Peak	35	$29	52	$104	17	$76	6%	5%	90%

Appendix A – Market Simulation Scenarios

Trade Date	Day-Ahead Market	Real-Time Market
9/1		
9/2		
9/3		
9/4		
9/5		
9/6		
9/7		
9/8		
9/9	34a – Increase RUC net-short by 20%	34b – Excess RUC in RT – RTN load forecast is 20-30% below RUC load forecast.
9/10	29 – Major line outage (Gates - Los Banos, Moenkopi – Eldorado, Four Corners – Moenkopi)	
9/11		8 – Verify HASP Export Scheduling Priority – Derate Mead, NOB, and Tracy
9/12	25e – Derate Mead and Eldorado by 25%	
9/13	25d – Derate AdlantoVictovl-SP by 25%	
9/14		
9/15		
9/16	25a – Derate PACI, LLNL_1_Tesla, TRCYPP_2_TESLA by 25% 28a – Derate Bay Area import capability – Tesla-Ravenwood, Tesla – Newark 230	28b – Derate Bay Area import capability – Tesla-Ravenwood, Tesla – Newark 230-
9/17	39 – Test SCIT – Derate SCIT to 4,000 MW	35 – Under-procure RUC – increase RT load forecast by 2,000 MW. 15 – Exercise RT exceptional dispatch -
9/18		
9/19	25j – Derate SMUD ITC, NOB_ITC, SYLMAR_ITC by 25%.	
9/20	10 – Insufficient supply DA IFM – Reduce total supply by 30%.	5 – Verify Daily Energy Limits are only relaxed in RTPD to avoid compromising reliability – selected units.
9/21	4 – Verify Daily Energy Limits are relaxed in DAM only for specific units.	
9/22		
9/23	2a – Verify conversion of Conditionally Qualified Self-Provided A/S bids to Energy bids in DAM – Case 1 2b - Verify conversion of Conditionally Qualified Self-Provided A/S bids to Energy bids in DAM – Case 1	
9/24	25c – Derate Palo Verde by 25%.	13 – Exercise RT Contingency Dispatch 14 – Exercise RT Manual Dispatch
9/25	29 – Major line outage (Gates - Los Banos, Moenkopi – Eldorado, Four Corners – Moenkopi)	
9/26	24a – Create spinning reserve deficiency - IFM. 45 – Test interaction of zonal A/S constraints	24b - Create spinning reserve deficiency – HASP/RT.
9/27	11 – Test insufficient demand in DA IFM	
9/28		
9/29		
9/30		

Appendix B – List of Competitive Paths

Table 1. Competitiveness of Candidate Paths (Corridors and Nomograms)

Corridors (Branch Groups)		
Candidate Path	**Competitive**	**MRTU Name**
Humboldt Bank	No	HUMBOLDT_XFBG
Monta Vista – Jefferson	No	MONTAVISTA_JEFSN_BG
PITSBRG_XFMRBG	No	PITSBRG_XFBG
SDGEIMP_LNXFMRBG	No	SDGEIMP_BG
HUMBOLDT_BG	Yes	HUMBOLDT_BG
Imperial Valley Bank	Yes	IVALLYBANK_XFBG
SDGE_CFEIMP_BG	Yes	SDGE_CFEIMP_BG
Serrano Bank	Yes	SERRANO_XFBG
SOUTHLUGO_BG	Yes	SOUTHLUGO_BG
Tesla to Delta Switchyard	Yes	TESLA_DELTASWYRD_BG
Tesla to Pittsburg	Yes	TESLAPITSBURG_BG
Vincent Bank	Yes	VINCNT_XFBG
Nomograms		
Candidate Path	**Competitive**	**MRTU Name**
Moss Landing to Metcalf	No	MOSSLDMETCALF_NG_SUM_OFFPK, MOSSLNDMETCALF_NG_SUM_ONPK, MOSSLNDMETCALF_NG_WIN
Vaca Bank & Tesla Bank 6	No	VACADX_TESLA_XFNG
MIGUEL_MAXIMP_LNXFMR BG	Yes	MIGUEL_MAXIMP_LXNF_NG
Pittsburg to San Mateo_E. Shore	Yes	PITSBRG_SANMAT_NG_SUM
Ravenswood Cutplane	Yes	RAVENSWD_NG_SUM, RAVENSWD_NG_WIN
Ravenswood to San Mateo	Yes	RAVENSWDSANMAT_NG_SUM, RAVENSWDSANMAT_NG_WIN
Tesla Banks 4 & 6	Yes	TESLA46_XFNG
Tesla Banks 6 & 4	Yes	TESLA64_XFNG
Victorville-Lugo (HA-NG)	Yes	VICTVLUGO_HANG_NG
Miguel 500/230 kV Banks	Yes	

Table 2. Candidate Paths Modeled as Competitive Tie Points Flowgates Under MRTU

Competitive Path	MRTU Name
30435_LAKVIL 2_230_30540_SOBRNT 4_230_1_CKT	30435_LAKEVILE_230_30540_SOBRANTE_230_BR_1 _1
30437_CROKET 3_230_30540_SOBRNT 4_230_1_CKT	30437_CROCKTAP_230_30540_SOBRANTE_230_BR_1 _1
30465_BAHIA 2_230_30460_VACADX 3_230_1_CKT	30460_VACA-DIX_230_30465_BAHIA _230_BR_1 _1
30467_PRKWAY 1_230_30460_VACADX 3_230_1_CKT	30460_VACA-DIX_230_30467_PARKWAY _230_BR_1 _1
30472_PEABDY 1_230_30460_VACADX 3_230_1_CKT	30460_VACA-DIX_230_30472_PEABODY _230_BR_1 _1
30478_LMBEPK 5_230_30460_VACADX 3_230_1_CKT	30460_VACA-DIX_230_30478_LAMBIE _230_BR_1 _1
30527_PITTSP 5_230_30555_SANRAM 1_230_1_CKT	30527_PITSBRG _230_30555_SANRAMON_230_BR_1 _1
30560_EASTSH 2_230_30700_SANMAT 8_230_1_CKT	30560_E. SHORE_230_30700_SANMATEO_230_BR_1 _1
30700_SANMAT 8_230_30567_TESSUB 2_230_1_CKT	30567_TES JCT _230_30700_SANMATEO_230_BR_1 _1
30569_KELSO 1_230_30570_USWND4 1_230_1_CKT	30569_KELSO _230_30570_USWP-RLF_230_BR_1 _1
30630_NEWARK 3_230_30624_TESLA 3_230_1_CKT	30624_TESLA E _230_30630_NEWARK _230_BR_1 _1
30685_EMBARC 2_230_99160_MARTIN 3_230_1_CKT	30685_EMBRCDR _230_99160_MAR-EMBE_230_BR_1 _1
30715_JEFRSN 1_230_30710_SLAC 2_230_1_CKT	30710_SLACTAP1_230_30715_JEFFERSN_230_BR_1 _1
30717_JEFRSN 4_230_99170_MARTIN 5_230_1_CKT	30717_TRAN230B_230_99170_MAR-JEF1_230_BR_1 _1
30717_JEFRSN 4_230_99170_MARTIN 5_230_1_CKT	30717_TRAN230B_230_99170_MAR-JEF1_230_BR_1 _2
30717_JEFRSN 4_230_99170_MARTIN 5_230_1_CKT	30717_TRAN230B_230_99170_MAR-JEF1_230_BR_1 _3
30717_JEFRSN 4_230_99170_MARTIN 5_230_1_CKT	30717_TRAN230B_230_99170_MAR-JEF1_230_BR_1 _4
31080_HUMBSB 4_60_31092_MPLCRK 1_60_1_CKT	31080_HUMBOLDT_60.0_31092_MPLE CRK_60.0_BR_1 _1
31110_BRDGVL 4_60_31112_FRTLND 1_60_1_CKT	31110_BRDGVLLE_60.0_31112_FRUITLND_60.0_BR_1 _1
33200_LARKIN 2_115_33203_MISSIX 1_115_1_CKT	33200_LARKIN _115_33203_MISSON _115_BR_1 _1
33200_LARKIN 2_115_33204_POTRPP 1_115_1_CKT	33200_LARKIN _115_33204_POTRERO _115_BR_1 _1
33200_LARKIN 1_115_33204_POTRPP 1_115_1_CKT	33200_LARKIN _115_33204_POTRERO _115_BR_1 _1
33200_LARKIN 2_115_33208_MARTIN 1_115_1_CKT	33200_LARKIN _115_33208_MARTIN C_115_BR_1 _1
33203_MISSIX 1_115_33204_POTRPP 1_115_1_CKT	33203_MISSON _115_33204_POTRERO _115_BR_1 _1
33205_HUNTER 1_115_33203_MISSIX 1_115_1_CKT	33203_MISSON _115_33205_HNTRS PT_115_BR_1 _1
33205_HUNTER 1_115_33203_MISSIX 1_115_2_CKT	33203_MISSON _115_33205_HNTRS PT_115_BR_2 _1
33205_HUNTER 1_115_33204_POTRPP 1_115_1_CKT	33204_POTRERO _115_33205_HNTRS PT_115_BR_1 _1
33206_BAYSHR 1_115_33204_POTRPP 1_115_1_CKT	33204_POTRERO _115_33206_BAYSHOR1_115_BR_1 _1
33205_HUNTER 1_115_33208_MARTIN 1_115_1_CKT	33205_HNTRS PT_115_33208_MARTIN C_115_BR_1 _1
33206_BAYSHR 1_115_33208_MARTIN 1_115_1_CKT	33206_BAYSHOR1_115_33208_MARTIN C_115_BR_1 _1
33208_MARTIN 1_115_33307_MILBRA 1_115_1_CKT	33208_MARTIN C_115_33307_MILLBRAE_115_BR_1 _1
30625_TESLA 5_230_37585_TRCYPP 5_230_1_CKT	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1
30625_TESLA 5_230_37585_TRCYPP 5_230_2_CKT	37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1
30560_EASTSH 2_230_99100_PITTSP 7_230_1_CKT	99100_PIT-ESH1_230_30560_E. SHORE_230_BR_1 _1
30560_EASTSH 2_230_99100_PITTSP 7_230_1_CKT	99100_PIT-ESH1_230_30560_E. SHORE_230_BR_1 _2
30624_TESLA 3_230_30040_TESLA 6_500_1_CKT	30040_TESLA _500_30624_TESLA E _230_XF_2 _P
30685_EMBARC 1_230_99158_MARTIN 7_230_1_CKT	30685_EMBRCDR _230_99158_MAR-EMBD_230_BR_2 _1
30701_SANMAT 5_1_30700_SANMAT 8_230_1_CKT	33310_SANMATEO_115_30700_SANMATEO_230_XF_5 _P
30702_SANMAT 6_1_30700_SANMAT 8_230_1_CKT	33310_SANMATEO_115_30700_SANMATEO_230_XF_6 _P
30704_SANMAT 7_1_30700_SANMAT 8_230_1_CKT	33310_SANMATEO_115_30700_SANMATEO_230_XF_7 _P
30715_JEFRSN 1_230_30712_SLAC 3_230_1_CKT	30712_SLACTAP2_230_30715_JEFFERSN_230_BR_2 _1
30735_METCLF 4_230_30042_METCLF 5_500_1_CKT	30735_METCALF _230_30042_METCALF _500_XF_11
30735_METCLF 4_230_30042_METCLF 5_500_2_CKT	30735_METCALF _230_30042_METCALF _500_XF_12
30735_METCLF 4_230_30042_METCLF 5_500_3_CKT	30735_METCALF _230_30042_METCALF _500_XF_13

Competitive Path	MRTU Name
30750_MOSSLD11_230_30045_MOSSLD13_500_1_CKT	30750_MOSSLD _230_30045_MOSSLAND_500_XF_9
33205_HUNTER 1_115_33208_MARTIN 1_115_2_CKT	33205_HNTRS PT_115_33208_MARTIN C_115_BR_1 _1
33207_BAYSHR 2_115_33204_POTRPP 1_115_1_CKT	33204_POTRERO _115_33207_BAYSHOR2_115_BR_2 _1
33207_BAYSHR 2_115_33208_MARTIN 1_115_1_CKT	33207_BAYSHOR2_115_33208_MARTIN C_115_BR_2 _1
33208_MARTIN 1_115_30695_MARTIN 2_230_1_CKT	33208_MARTIN C_115_30695_MARTIN C_230_XF_7
33208_MARTIN 1_115_30695_MARTIN 2_230_2_CKT	33208_MARTIN C_115_30695_MARTIN C_230_XF_8
33208_MARTIN 1_115_33310_SANMAT 1_115_1_CKT	33208_MARTIN C_115_33310_SANMATEO_115_BR_3 _1
33208_MARTIN 1_115_33322_UNTDQF 2_115_1_CKT	33208_MARTIN C_115_33322_UAL TAP _115_BR_5 _1
33303_EGRAND 1_115_33208_MARTIN 1_115_1_CKT	33208_MARTIN C_115_33303_EST GRND_115_BR_2 _1
33303_EGRAND 1_115_33308_SFIAMA 1_115_1_CKT	33308_SFIA-MA _115_33303_EST GRND_115_BR_2 _1
22052_BQUTOS 2_138_22648_PQUTOS 3_138_1_CKT	22052_BATIQTP _138_22648_PENSQTOS_138_BR_1 _1
22227_ENCINA 6_230_22716_SANLUS 2_230_1_CKT	22227_ENCINATP_230_22716_SANLUSRY_230_BR_1 _1
22052_BQUTOS 2_138_22228_ENCINA 4_138_1_CKT	22228_ENCINA _138_22052_BATIQTP _138_BR_1 _1
22260_ESCNDO 6_230_22844_TALEGA 2_230_1_CKT	22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1
22227_ENCINA 6_230_22261_PALOMR 4_230_1_CKT	22261_PALOMAR _230_22227_ENCINATP_230_BR_1 _1
22260_ESCNDO 6_230_22261_PALOMR 4_230_1_CKT	22261_PALOMAR _230_22260_ESCNDIDO_230_BR_1 _1
22260_ESCNDO 6_230_22261_PALOMR 4_230_2_CKT	22261_PALOMAR _230_22260_ESCNDIDO_230_BR_2 _1
22464_MIGUEL 1_230_22504_MSSION 1_230_1_CKT	22464_MIGUEL _230_22504_MISSION _230_BR_1 _1
22464_MIGUEL 1_230_22504_MSSION 1_230_2_CKT	22464_MIGUEL _230_22504_MISSION _230_BR_2 _1
22464_MIGUEL 1_230_22832_SXCYN 2_230_1_CKT	22464_MIGUEL _230_22832_SYCAMORE_230_BR_1 _1
22464_MIGUEL 1_230_22832_SXCYN 2_230_2_CKT	22464_MIGUEL _230_22832_SYCAMORE_230_BR_2 _1
22464_MIGUEL 1_230_22596_OLDTWN 1_230_1_CKT	22596_OLD TOWN_230_22464_MIGUEL _230_BR_1 _1
22504_MSSION 1_230_22596_OLDTWN 1_230_1_CKT	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1
22504_MSSION 1_230_22596_OLDTWN 1_230_2_CKT	22596_OLD TOWN_230_22504_MISSION _230_BR_2 _1
22596_OLDTWN 1_230_22652_PQUTOS 1_230_1_CKT	22652_PENSQTOS_230_22596_OLD TOWN_230_BR_1 _1
22232_ENCINA 5_230_22716_SANLUS 2_230_1_CKT	22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1
22504_MSSION 1_230_22716_SANLUS 2_230_1_CKT	22716_SANLUSRY_230_22504_MISSION _230_BR_1 _1
22504_MSSION 1_230_22716_SANLUS 2_230_2_CKT	22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1
22261_PALOMR 4_230_22832_SXCYN 2_230_1_CKT	22832_SYCAMORE_230_22261_PALOMAR _230_BR_1 _1
24804_DEVERS 4_230_24132_SBERDO10_230_1_CKT	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1
24804_DEVERS 4_230_24132_SBERDO10_230_2_CKT	24804_DEVERS _230_24132_SANBRDNO_230_BR_2 _1
24804_DEVERS 4_230_24901_VISTA 3_230_1_CKT	24901_VSTA _230_24804_DEVERS _230_BR_1 _1
33307_MILBRA 1_115_33310_SANMAT 1_115_1_CKT	33307_MILLBRAE_115_33310_SANMATEO_115_BR_1 _1
33312_BELMNT 1_115_33310_SANMAT 1_115_1_CKT	33310_SANMATEO_115_33312_BELMONT _115_BR_1 _1
99102_PITTSP 6_230_30567_TESSUB 2_230_1_CKT	99102_PIT-TES1_230_30567_TES JCT _230_BR_1 _1
99102_PITTSP 6_230_30567_TESSUB 2_230_1_CKT	99102_PIT-TES1_230_30567_TES JCT _230_BR_1 _2
33306_SFARPT 1_115_33322_UNTDQF 2_115_1_CKT	33322_UAL TAP _115_33306_SFIA _115_BR_5 _1
33310_SANMAT 1_115_33306_SFARPT 1_115_1_CKT	33306_SFIA _115_33310_SANMATEO_115_BR_5 _1
33310_SANMAT 1_115_33308_SFIAMA 1_115_1_CKT	33310_SANMATEO_115_33308_SFIA-MA _115_BR_2 _1
37514_TRACY5 1_230_30035_TRACY5 3_500_1_CKT	30035_TRACY _500_37514_TRACY1 _230_XF_1
37515_TRACY5 2_230_30035_TRACY5 3_500_1_CKT	30035_TRACY _500_37515_TRACY2 _230_XF_2
99106_SANMAT10_230_99106_SANMAT11_230_1_CKT	
24805_DEVERS 1_115_24804_DEVERS 4_230_1_CKT	24805_DEVERS _115_24804_DEVERS _230_XF_1
24805_DEVERS 1_115_24804_DEVERS 4_230_2_CKT	24805_DEVERS _115_24804_DEVERS _230_XF_4
24805_DEVERS 1_115_24804_DEVERS 4_230_3_CKT	24805_DEVERS _115_24804_DEVERS _230_XF_3