California ISO
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California ISO

Quarterly Report on Market Issues and Performance

June 2, 2010

Prepared by: Department of Market Monitoring

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Executive Summary

This report provides an overview of general market performance during the first quarter (Q1) of 2010 (January – March). The report also provides detailed analysis of two special issues: the SCE Percent Import Limit and implementation of minimum online constraints in the day-ahead energy market. Highlights from the report include:

- The day-ahead integrated forward market has continued to be very stable and competitive. Energy prices in the day-ahead market continued to be approximately equal to benchmark prices estimated under perfectly competitive conditions.
- Real-time prices in the SCE LAP increased to about seventeen percent above the day-ahead market competitive benchmark in January and February due to price impacts from more frequent congestion on the SCE Percent Import Limit. However, the overall market impact of higher real-time prices was relatively low since an average of about 97 percent of load was scheduled in the day-ahead market.
- The frequency of day-ahead congestion on inter-ties with other regions was significantly lower in Q1 2010 than in Q1 2009, with the exception of the Silver Peak inter-tie. This inter-tie was de-rated for a significant portion of Q1 2010.
- The SCE Percent Import Limit was binding more frequently in Q1, increasing prices in the SCE area in both day-ahead and real-time energy markets. Analysis by DMM indicates that manual adjustments made to conform market limits were generally consistent with the observed discrepancies between market and physical flows. In many cases, false congestion was averted by conforming the market limit higher. However, conforming is an imperfect manual solution to the problem of modeling inaccuracies.
- In February, minimum online constraints reflecting the G-217 and G-219 operating procedures were incorporated in the day-ahead energy market. Analysis by DMM indicates that this modeling modification has resulted in a more economically efficient commitment and dispatch of units compared to the prior process of adding these constraints in the residual unit commitment process.[1] When units needed to meet these constraints are committed in the day-ahead energy market, these resources can also be scheduled to provide additional energy and ancillary services. Analysis by DMM indicates that in hours when resources were committed by these constraints, additional energy from these units lowered the day-ahead market price slightly. This can also be expected to reduce bid cost recovery payments compared to the prior process of committing units to meet these constraints in the residual unit commitment process.

Provided below is a summary of the market issues and findings in the three sections of this report.

Energy markets

- The day-ahead integrated forward market has continued to be very stable and competitive. Energy prices in the day-ahead market during each month of Q1 continued to be approximately equal to

[1] Since August 2009, these constraints were incorporated in the residual unit commitment process performed after the day-ahead energy market.

benchmark prices estimated under perfectly competitive conditions. A very high portion of load and supply was scheduled in the day-ahead market (e.g., typically 95 to 100 percent).

- The frequency of prices in excess of the $500/MWh bid cap in the real-time market increased during January and February of 2010. This increased the average real-time prices significantly above the competitive baseline prices for the day-ahead market for that month. This was driven by more frequent congestion on the SCE Percent Import Limit during these months. Real-time market prices returned to competitive baseline levels in March 2010.
- Prices for the PG&E and SDG&E load aggregation points were highly consistent in the day-ahead, hour-ahead and real-time energy markets. However, for the SCE load aggregation point, hour-ahead and real-time prices were significantly higher than day-ahead prices in January and February. This divergence was driven by SCE Percent Import Limit binding.

Congestion

- The frequency of congestion on inter-ties with other regions was significantly lower in Q1 2010 than in Q1 2009, with the exception of the Silver Peak inter-tie.
- The frequency of day-ahead congestion on Mead in Q1 2010 was comparable to Q1 2009, but significantly higher than Q3 and Q4 of 2009. The Mead inter-tie was congested 38 percent of the time in the first quarter of 2010. Congestion occurred primarily during the peak hours. A primary driver of the high congestion was less scheduling flexibility on that inter-tie coupled with decreases in transmission availability.
- The frequency of congestion on Palo Verde decreased in Q1 2010 despite scheduled work in late January and increased demand for capacity on Palo Verde resulting from outages on other paths in the area. During this period Palo Verde was congested 14 percent of the time, with an average shadow price of $8/MW.
- The IPPDCADLN_BG was the most frequently congested constraint, with congestion occurring primarily in the day-ahead market. This constraint was congested 21 percent of the hours in the day-ahead market, with an average shadow price of $4/MWh.

Ancillary services

- Quarterly ancillary service costs were 37 percent lower in the first quarter of 2010 compared to the same months in 2009, prior to implementation of the new market design and co-optimization of ancillary services.
- The average day-ahead prices of regulation up in January and February were about $5.66/MW but increased to $8.41/MW in March due to tighter supply of regulation up.
- Prices for regulation down increased slightly compared to 2009 Q4 due to the increase in opportunity cost to provide regulation down in the early morning off-peak hours.
- Prices for spin and non-spin reserve cleared prices in the first quarter of 2010 remained low primarily due to lower requirements corresponding to lower seasonal loads during this period.

SCE percent import limit

The ISO implemented the SCE Percent Import Limit in the network model in November of 2009.[2] Since that time, this constraint has frequently been binding in both the day-ahead and real-time markets, with material impacts on energy prices in those markets.

The SCE Percent Import limit is dynamic, and measurement of the extent to which the constraint is binding in real time is susceptible to inaccuracies where actual physical flow and market calculated flow diverge. The constraint considers generation levels, import levels, and load all within the SCE area. Actual values for these three components may change from one interval to the next. However, the limit for this constraint that is used in real time relies on a static hourly load figure and limited changes in import levels in RTD. This difference between actual and market limits can result in a discrepancy that must be reconciled by grid operators in real time. Thus, operators may need to adjust or *conform* the constraint in real-time to account for two factors:

- Differences between the market limit in the software and the actual physical limit, taking into account actual generation levels, import levels, and load all within the SCE area; and
- Differences between actual flows and modeled flows on this import limit.

The second section of this report provides an analysis of this practice on the SCE Percent Import Limit. Key points from that section include:

- The SCE Percent Import Limit was binding more frequently in Q1, increasing energy prices in the SCE area in both day-ahead and real-time prices. The constraint was binding less frequently beginning early March as a result of operators conforming the constraint limit upwards.
- Analysis indicates that there are often differences between the physical and market flows on this constraint. Conforming the market limit higher averted false congestion prices in most cases. However, in a limited number of cases, congestion appeared in the market when the physical flow on this constraint was still below the limit.
- There were a few hours between April 1 and April 14 where the physical flow was at or above the constraint limit. In these cases the constraint conforming practice may have precluded congestion from being triggered in the real-time market when actual flows reached or exceeded the physical limit for this constraint.
- Analysis of one week in January indicates that the downward conforming practice was consistent with managing actual physical flows that were approaching or at the constraint limit, so that market congestion and prices in these circumstances reflected actual scarcity.
- DMM recommends regular analysis, reporting, and feedback on this issue (and similar constraints) to improve the process and provide timely information and transparency to participants.

[2] The SCE Percent Import Limit is a technical limit on the ratio of imported power to meet load within the SCE region. This limit is intended to ensure a minimum level of local generation in the unlikely event that the SCE area were to separate from the rest of the Western grid due to a significant drop in system-wide frequency. This constraint restricts total imports into the SCE area to be below 60 percent of SCE load, adjusted for pump load and the SCE share of San Onofre nuclear generation.

Minimum online constraints in the day-ahead energy market

Starting February 5, 2010, the ISO began enforcing the G-217 and G-219 operating procedures in the day-ahead integrated forward market using a newly created market model feature, referred to as a minimum online commitment (MOC) constraint. Since August 2009, the reliability requirements addressed through these operating procedures were met through an energy-based nomogram enforced only in the residual unit commitment process of the day-ahead market. Prior to that time the ISO enforced these operating procedures through exceptional dispatch.

DMM has performed an analysis of this new modeling feature by re-running the day-ahead market software for a sample of nine days with and without this constraint incorporated in the day-ahead energy market. This analysis shows that:

- Prices generally decreased slightly with the G-219 minimum online commitment constraint enforced in the day-ahead energy market. This results from the fact that when additional capacity is committed in the day-ahead market, this shifts the supply curve to the right and allows a slightly lower priced bid to set the marginal price.
- The application of the G-219 minimum online commitment constraint in the day-ahead market appears to have increased overall market efficiency. Specifically, our analysis shows that:
  - In all nine days included in this analysis, the minimum online commitment requirements under G-219 would not have been met by the day-ahead energy market solution without this constraint being enforced in the market software. As noted above, this would have required additional units be committed via residual unit commitment or exceptional dispatch before the time when this constraint was incorporated directly into the day-ahead energy market.
  - Generators committed to meet the minimum online commitment constraint were generally dispatched above their minimum operating level in the day-ahead market, particularly during peak hours. This indicates that these resources, once committed, were economic and were able to take advantage of revenue opportunities in the day-ahead market. It also indicates that bid-cost recovery uplift associated with the start-up and minimum load cost for these resources may be reduced since these units appear to earn significant revenues from energy sales in the day-ahead market.
  - Enforcement of the G-219 minimum online commitment constraint has not caused over-commitment of effective generators. On days where the G-219 minimum online commitment constraint was enforced, the market software only committed enough capacity to meet the constraint.

1 Review of market performance

1.1 Energy market

Monthly competitive index

This section provides an assessment of the overall competitiveness of the integrated forward market and real-time market. Key findings of this chapter include the following:

- The day-ahead integrated forward market has continued to be very stable and competitive, with a very high portion of load and supply being scheduled in the day-ahead market (e.g., typically 95 to 100 percent).
- Energy prices in the day-ahead market during each month of the first quarter of 2010 continue to be approximately equal to benchmark prices estimated under perfectly competitive conditions. These simulations produce competitive baseline prices that DMM develops by re-simulating the day-ahead market with default energy bids reflecting each unit's actual marginal cost.
- The frequency of prices in excess of the $500/MWh bid cap in the real-time market increased during January and February of 2010. This increased the average real-time prices significantly above the competitive baseline prices for the day-ahead market for that month. Real-time market prices returned to competitive baseline levels in March 2010.

Day-ahead scheduling of load

As shown in Figure 1.1 and Figure 1.2, the amount of load scheduled in the day-ahead market continues to be very high, with 95 to 99 percent of real-time load being scheduled in the day-ahead market in Q1 2010, consistent with Q4 2009 findings. The level of load scheduled in the day-ahead market can represent a key indicator of overall market efficiency and competitiveness. If the amount of load scheduled in the day-ahead market is close to the actual level of load in real-time, this generally indicates sufficient supply was made available and load bids were sufficiently flexible that a more efficient commitment and scheduling resulted. High levels of load scheduling in the day-ahead market can also indicate that markets are competitive and that market power is being effectively mitigated. Finally, when load scheduled in the day-ahead is near actual load, the impact of extremely high or low real-time prices is low, because a relatively small portion of demand and supply is actually being settled at the real-time price.

Off-peak hours generally have higher scheduling percentages compared to on-peak hours. This is due to the amount of excess energy from online resources running at minimum load to be available during higher load hours. During the evening load ramp, the percentage of scheduling is lower due to the sudden increase in load, which can be up to three thousand megawatts in an hour during winter months. This increase in load, and the subsequent move up the supply curve, causes price responsive load to procure less at these higher prices.

Figure 1.1 Day-ahead load scheduling by operating hour (Q1 2010)

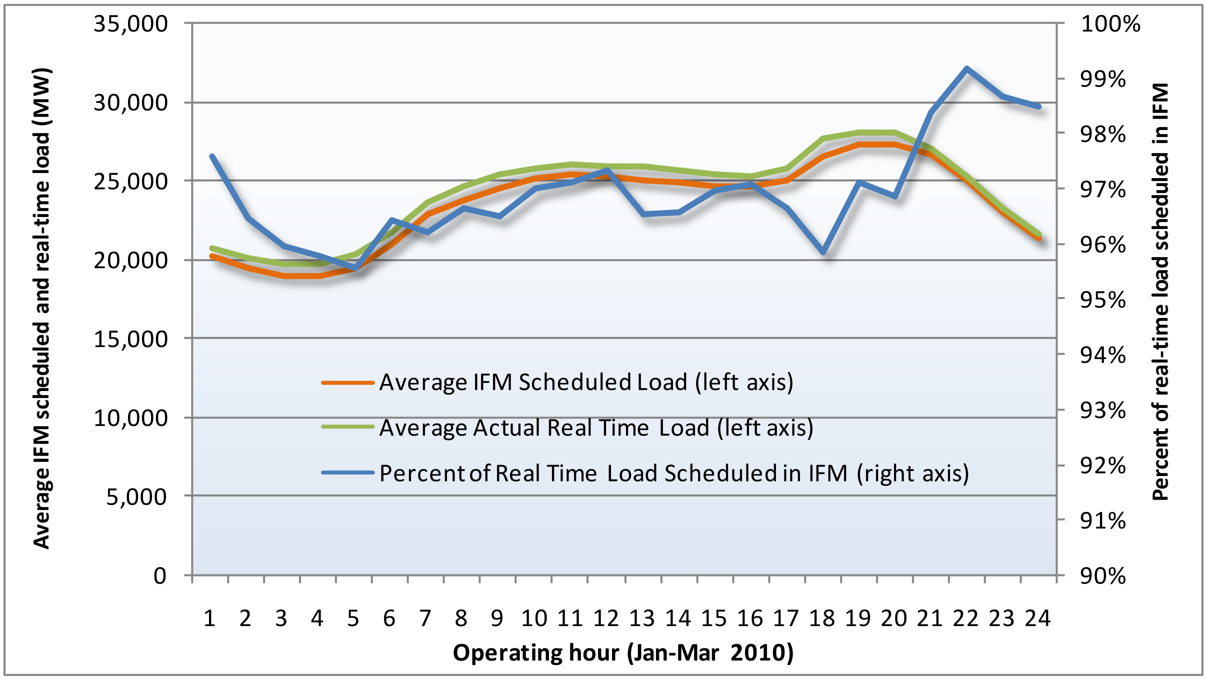
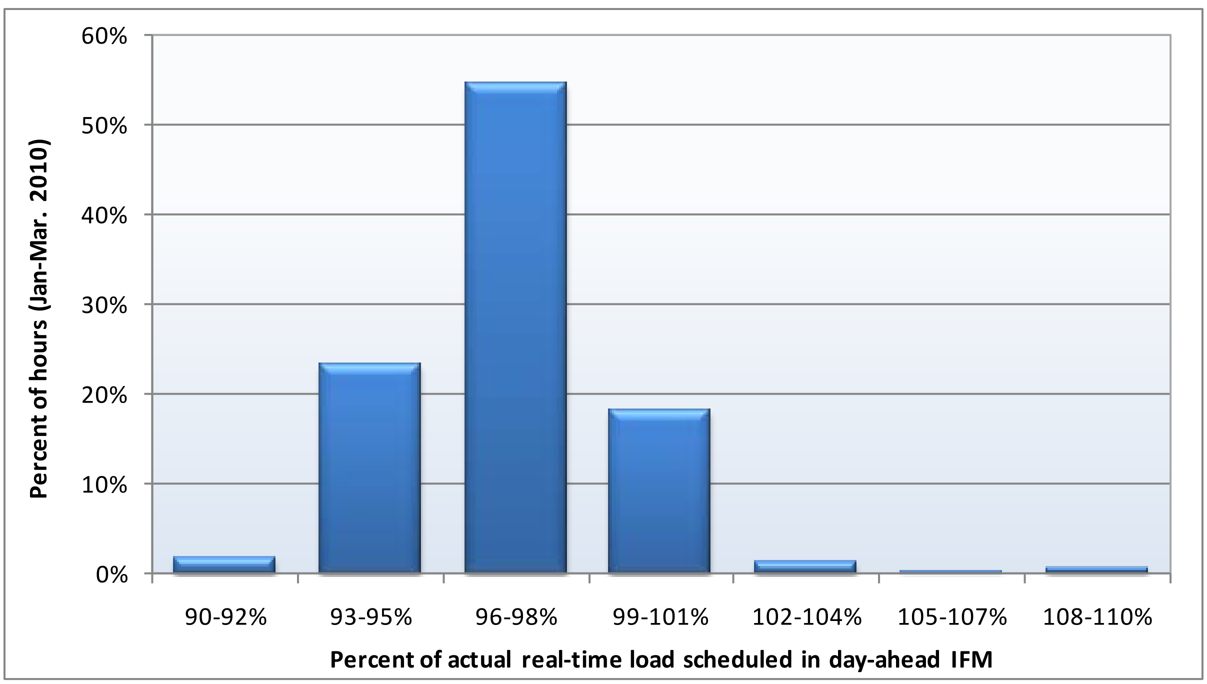


Figure 1.2 Percent of real-time load scheduled in the day-ahead IFM (Q1 2010)



Market competitiveness

To assess the competitiveness of the day-ahead market, DMM runs two simulations using its stand-alone copy of the day-ahead integrated forward market software.

- The first is a re-run of the market software using data for the applicable Save Case (the archive of market and system inputs and settings saved after completion of the final day-ahead market run). Results of this initial re-run are benchmarked against actual market results to validate that the DMM stand-alone system is accurately reproducing results of the actual market software.[3] Days for which the stand-alone system does not produce results comparable to the actual market run are excluded from the analysis.[4]
- The second run of the stand-alone day-ahead market software is designed to represent a perfectly competitive scenario which provides a competitive baseline against which the re-run of actual market prices can be compared. In this second run, bids for gas-fired generating resources are replaced with their respective default energy bids, which are designed to represent each unit's actual variable or opportunity costs.[5] This run reflects the assumption that under perfectly competitive conditions, each resource would bid at their marginal operating or opportunity costs. The percentage difference between actual market prices and prices resulting under this competitive baseline scenario represents the price-cost mark-up index for the day-ahead market. Generally, DMM considers a market to be competitive if the index indicates no more than a 10 percent mark-up over the competitive baseline.

Figure 1.3 through Figure 1.5 show monthly summary results of this competitive baseline analysis for each of the three load aggregation points in the system. The green bar (IFM Actual) represents the weighted average price for each load aggregation point for the days that were re-run using actual market inputs (see left vertical axis). The blue bar (Competitive Baseline) shows the weighted average price for each load aggregation point for these same days based on the re-run performed using default energy bids for gas-fired generation. The orange line in each figure represents price-cost mark-up, or the percentage difference between actual prices and the prices under the competitive baseline (see right vertical axis). As illustrated in these figures, the monthly price-cost mark-up ranged from -2 percent to -4 percent across the three months and three load aggregation points.

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[3] Results of the market software and DMM's stand-alone version can vary for several reasons. First, because these two systems are managed and updated independently, the DMM system may sometimes be running with a somewhat previous version of the actual market software. In addition, differences may occur due to changes in one or more settings that may have been made between the pre-IFM market power mitigation, integrated forward market and residual unit commitment runs. Data archived in Save Cases represent settings used in the final residual unit commitment run. Thus, if any changes in settings (such as the MIP gap, for example) are made between the pre-IFM market power mitigation, integrated forward market and residual unit commitment runs during actual market operations, a re-run based on the settings used in the final residual unit commitment run that are archived in the Save Case data may not duplicate the actual day-ahead market results.

[4] For this first quarter 2010 report, results were excluded for 5 out of 31 days in January; 13 out of 28 days in February; and 3 out of 31 days in March. DMM expects the portion of re-runs that do not accurately replicate market outcomes (and are therefore excluded from such analyses) to decrease as updates to the market software decline, and DMM is able to successfully perform a greater portion of re-runs with a smaller lag time from the date of actual market operations.

[5] Under the market power mitigation provisions of the tariff, cost-based default energy bids are increased by 10 percent to reflect potential costs that may not be entirely captured in the standard fuel and variable cost calculations upon which cost-based default energy bids are based (Section 39.7.1.1). Units such as use-limited resources may also have a default energy bid that reflects their opportunity costs under the negotiated cost option of the tariff (Tariff Section 39.7.1.3, and *Business Practice Manual for Market Instruments*, Version 1, Revised: Mar 26, 2009, D-3 to D-4).

Overall, the mark-up index indicates that monthly load aggregation point prices are within competitive ranges through the first nine months of the new market. The mark-up index for Q1 of 2010 shows slightly negative price-cost mark-ups, which are attributable to the fact that a significant amount of generators bid slightly below their default energy bids. Because cost-based default energy bids include a 10 percent adder above fuel and variable costs, these relatively small negative mark-ups are indicative of a competitive market and reflect the fact that actual bids for many units are designed to cover fuel and variable costs, but do not include the additional 10 percent multiplier included in default energy bids.

Meanwhile, average costs were generally higher during Q1 of 2010 relative to Q4 of 2009 in both the actual IFM and the competitive baseline scenario results. This increase can be explained by an increase of almost 10 percent in spot market prices for natural gas during 2010 Q1 compared to 2009 Q4.

Figure 1.3 PG&E LAP competitive baseline index (Q2-2009 through Q1-2010)

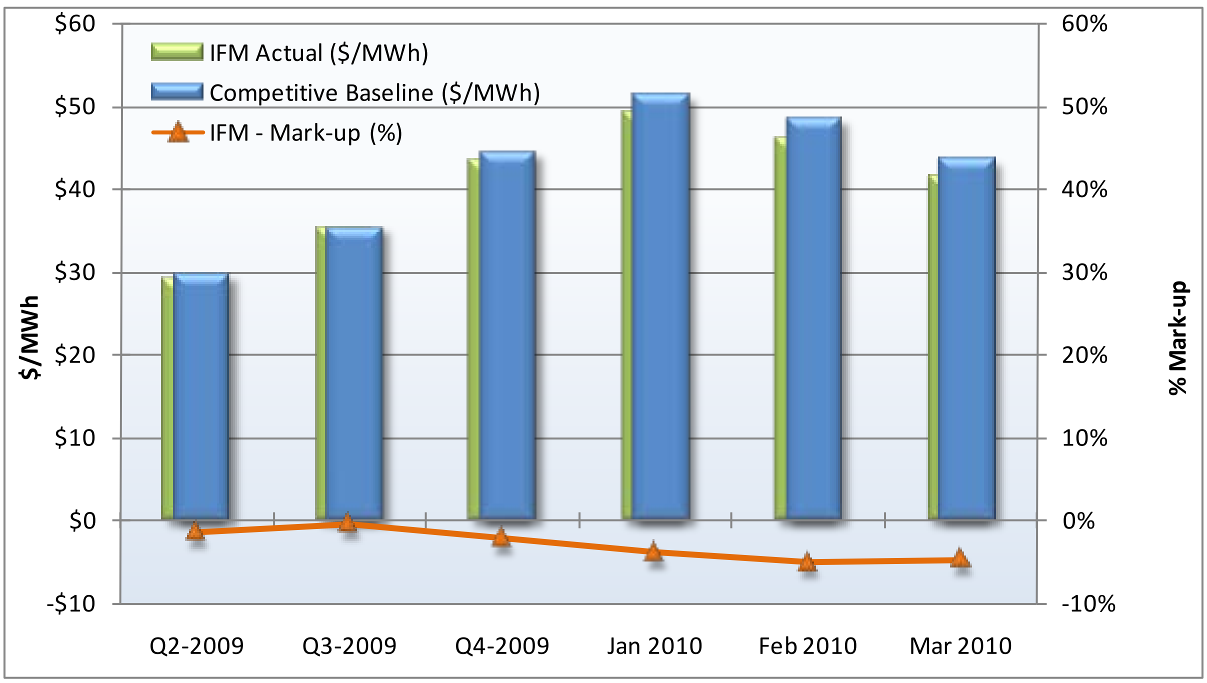


Figure 1.4 SCE LAP competitive baseline index (Q2-2009 through Q1-2010)

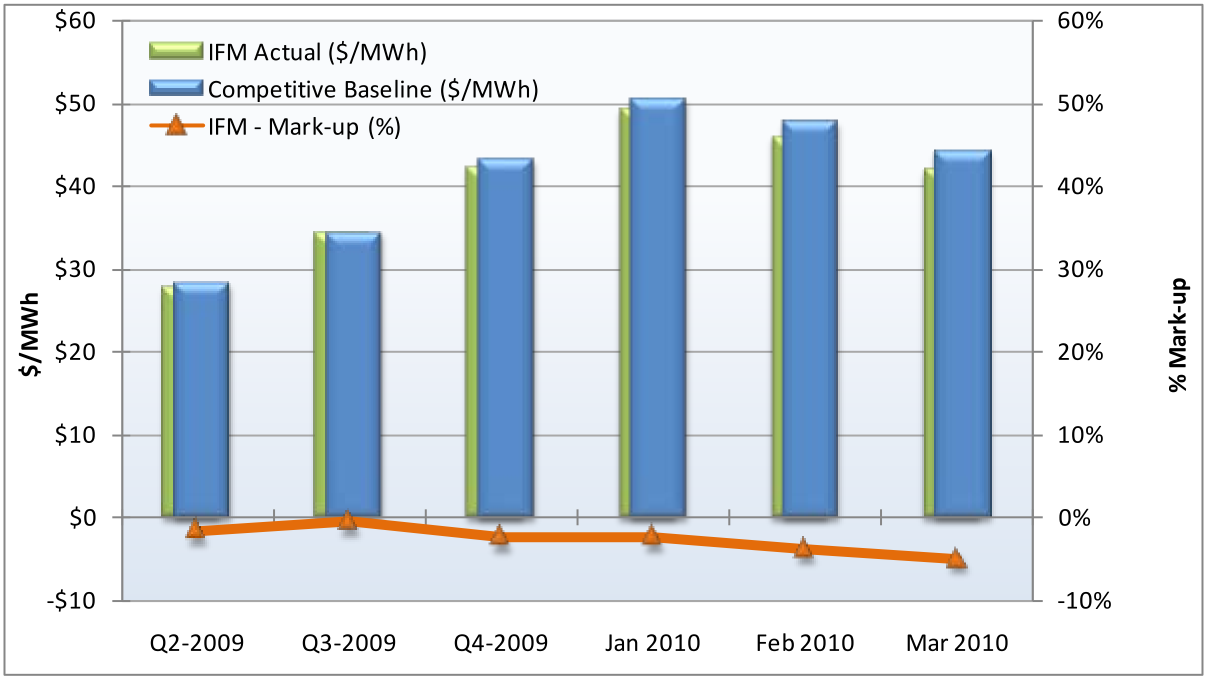


Figure 1.5 SDG&E LAP competitive baseline index (Q2-2009 through Q1-2010)

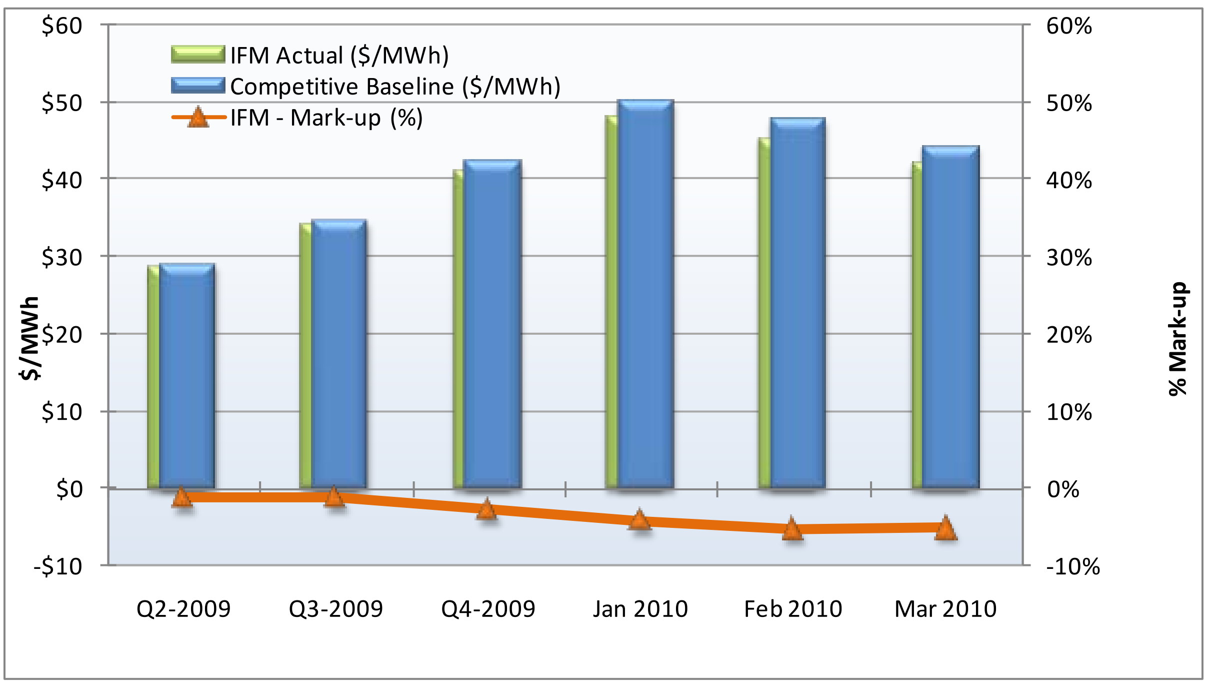
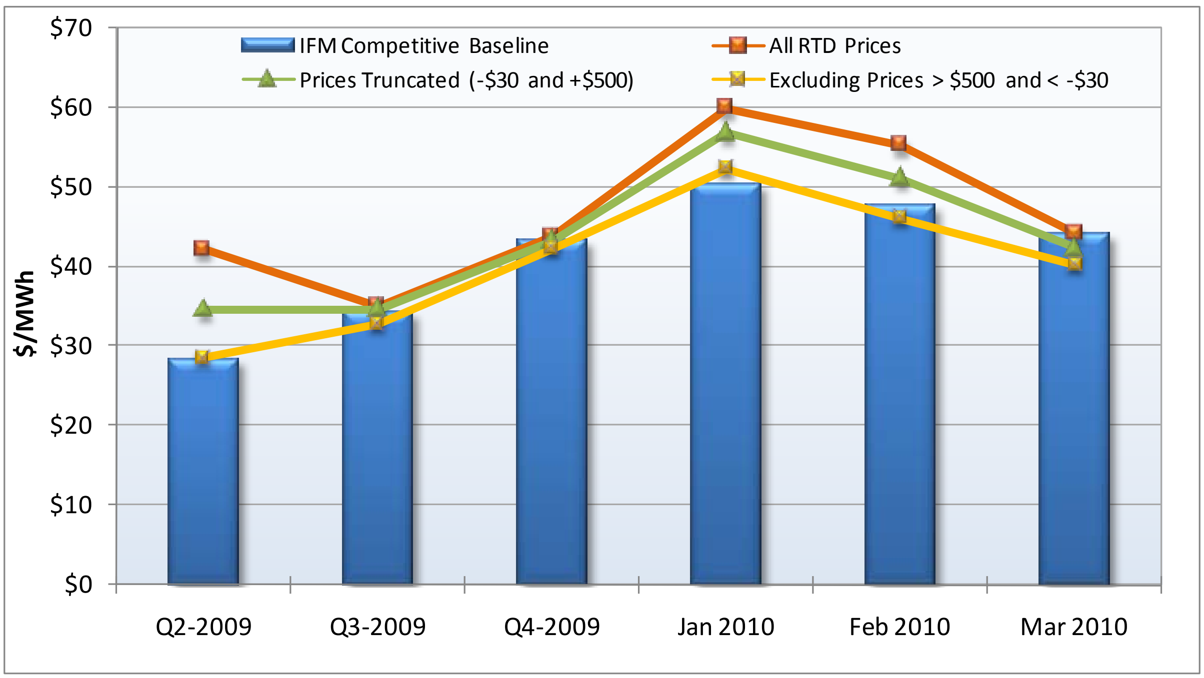


Figure 1.6 compares the competitive baseline price calculated by DMM using the IFM software for the SCE load aggregation point to three different averages of 5-minute real-time SCE prices. As shown in Figure 1.6, when extremely high or low real-time prices (greater than $500 or less than -$30) are excluded, average real-time prices for each of the three months are essentially equal to the competitive baseline estimate. For purposes of this comparison, we believe it is appropriate to exclude such extreme prices when making this comparison given that real-time prices reflect 5-minute operating constraints that cannot be captured in the competitive baseline estimate, which is produced using the day-ahead market software.

Figure 1.6 also provides two additional comparisons based on real-time prices with less screening of extreme prices, including one that includes all 5-minute prices but truncates extreme prices at the bid caps (green line), and a second comparison that includes all 5-minute prices with no prices excluded or truncated (orange line). As shown in Figure 1.6, these other two comparisons were significantly higher than the competitive baseline in January and February of 2010, and then converged to the competitive baseline in March of 2010. The significant difference using these two other comparisons and the competitive baseline during January and February 2010 can be explained by the increased frequency of extreme real-time prices, which was caused largely by congestion on the SCE import branch group.

Figure 1.6 Comparison of SCE LAP competitive baseline to real-time prices

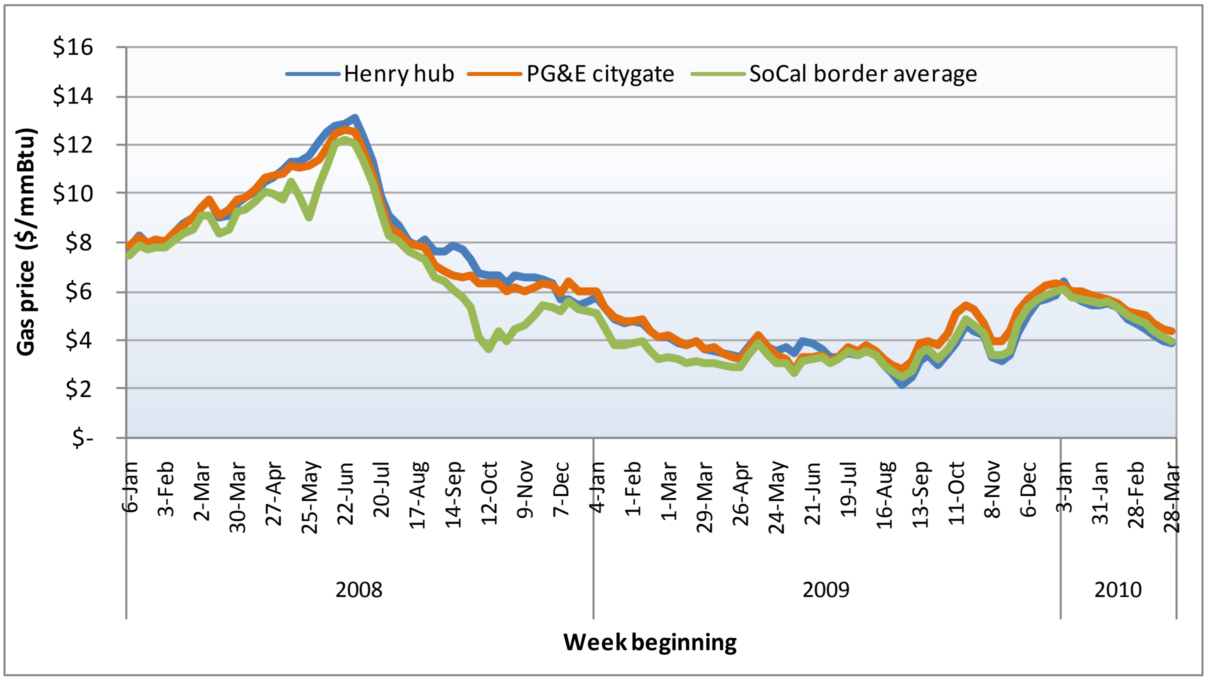


While SCE experienced higher frequency of real-time price spikes during Q1 of 2010 due largely to congestion on the SCE Import Branch Group, PG&E and SDG&E real-time load aggregation point prices were comparable to or just below the competitive baseline during the same period.

Natural gas prices by week for last 24 months

Natural gas prices had increased in December of 2009 to $6/mmBtu. In early January they began to decline and have done so steadily throughout the first quarter of 2010 to about $4/mmBtu by the end of March 2010.

Figure 1.7 Natural gas prices for Q1 2008 through Q1 2010



Monthly average prices

Monthly average prices for load aggregation points were slightly higher in the first quarter of 2010 than in the last quarter of 2009, as illustrated in Figure 1.8 and Figure 1.9.

In the SCE load aggregation point, prices in the hour-ahead and real-time markets were significantly higher than prices in the day-ahead market. This divergence was driven primarily by more frequent price spikes resulting from the SCE percent import limit binding. The impact of the SCE percent import limit on energy prices is covered in more detail in the second section of this report.

Monthly average prices in all three markets tracked downward over the quarter, reflecting the trend in spot market gas prices in the SCE load aggregation point in both January and February.

Energy prices in the PG&E and SDG&E load aggregation points converged well across the three temporal markets, and also exhibited the same downward trend across the quarter as the SCE load aggregation point. Convergence between hour-ahead and real-time prices for the PG&E load aggregation point are shown in Figure 1.10. Convergence in January and February was good in both peak and off-peak hours. In March, slightly higher off-peak prices in the hour-ahead scheduling process resulted in some divergence; however, the peak hour prices were highly consistent across the three energy markets.

Figure 1.8 Monthly average LAP LMP for the SCE LAP (peak hours)

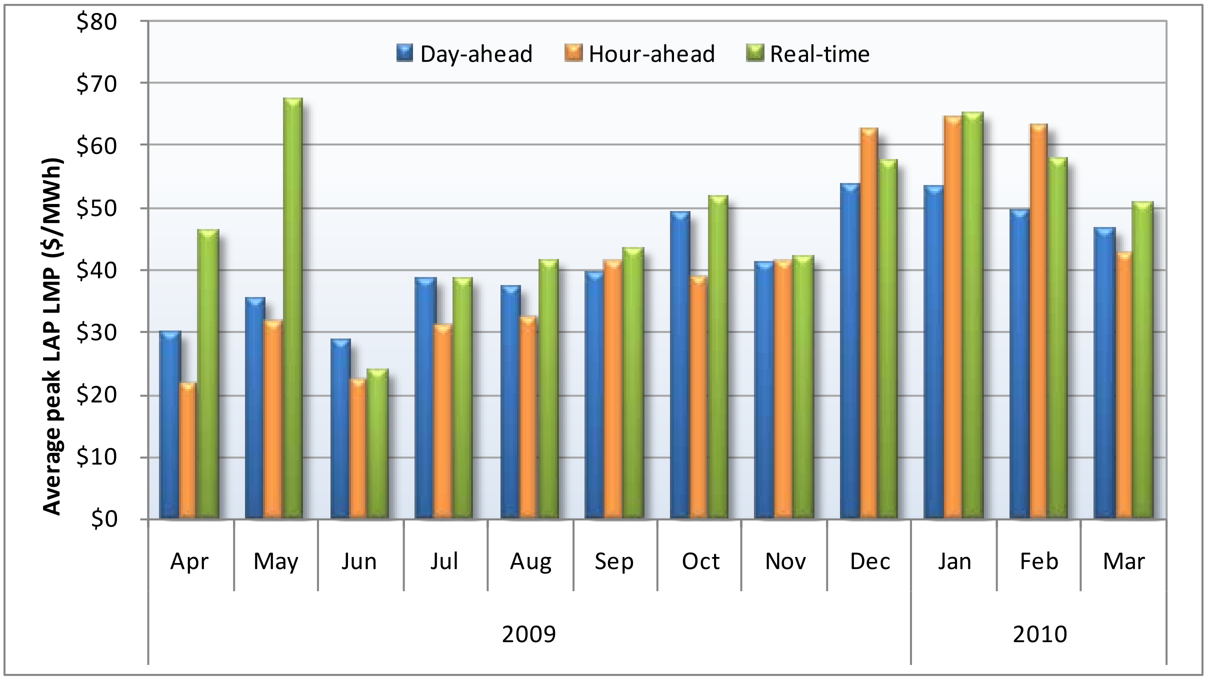


Figure 1.9 Monthly average LAP LMP for the SCE LAP (off-peak hours)

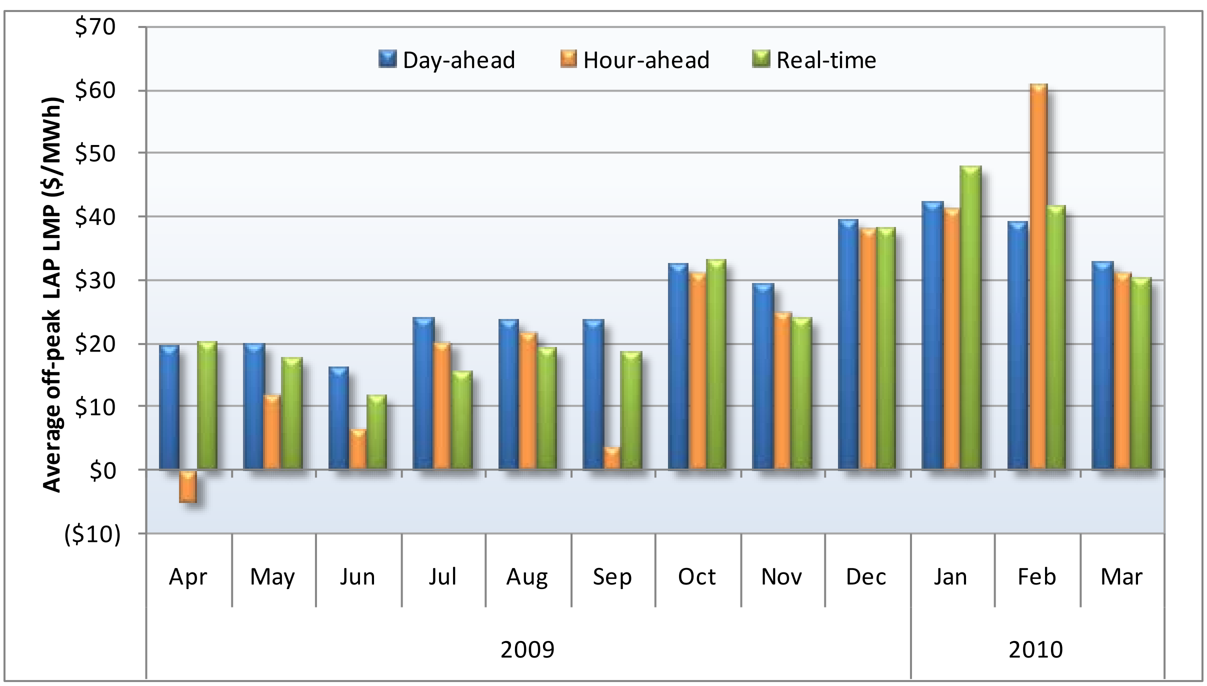
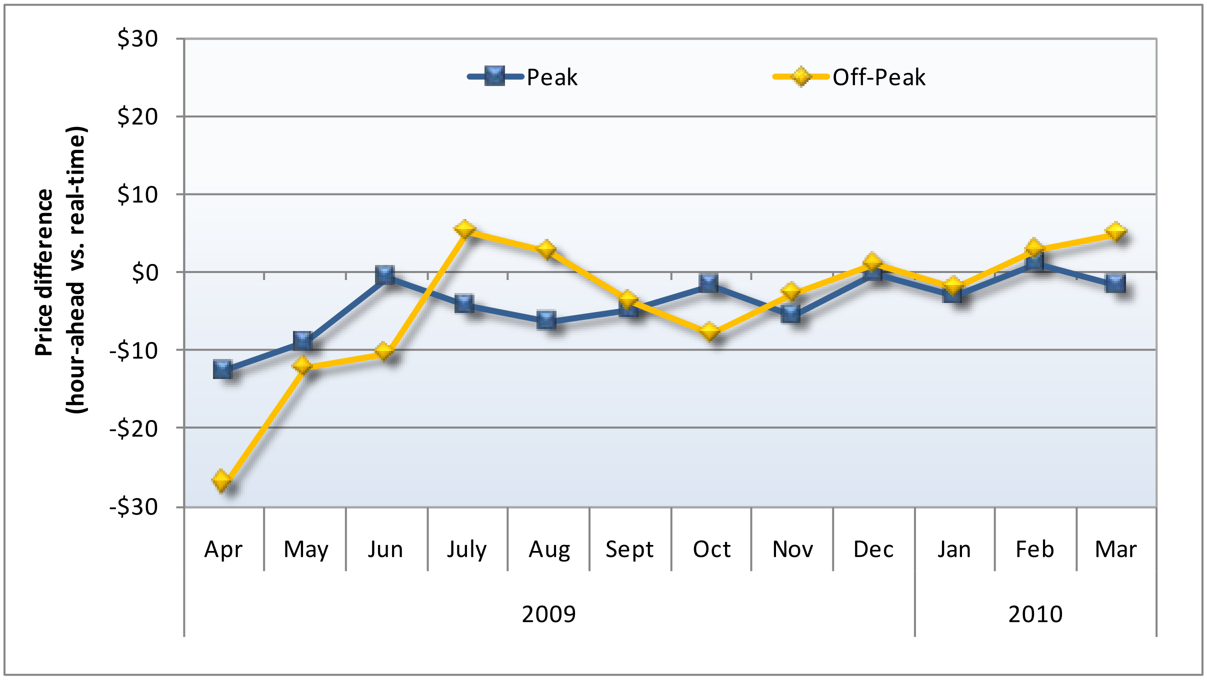


Figure 1.10 Convergence between hour-ahead and real-time LAP LMPs – PG&E LAP



1.2 Congestion, exceptional dispatch, and transmission conforming

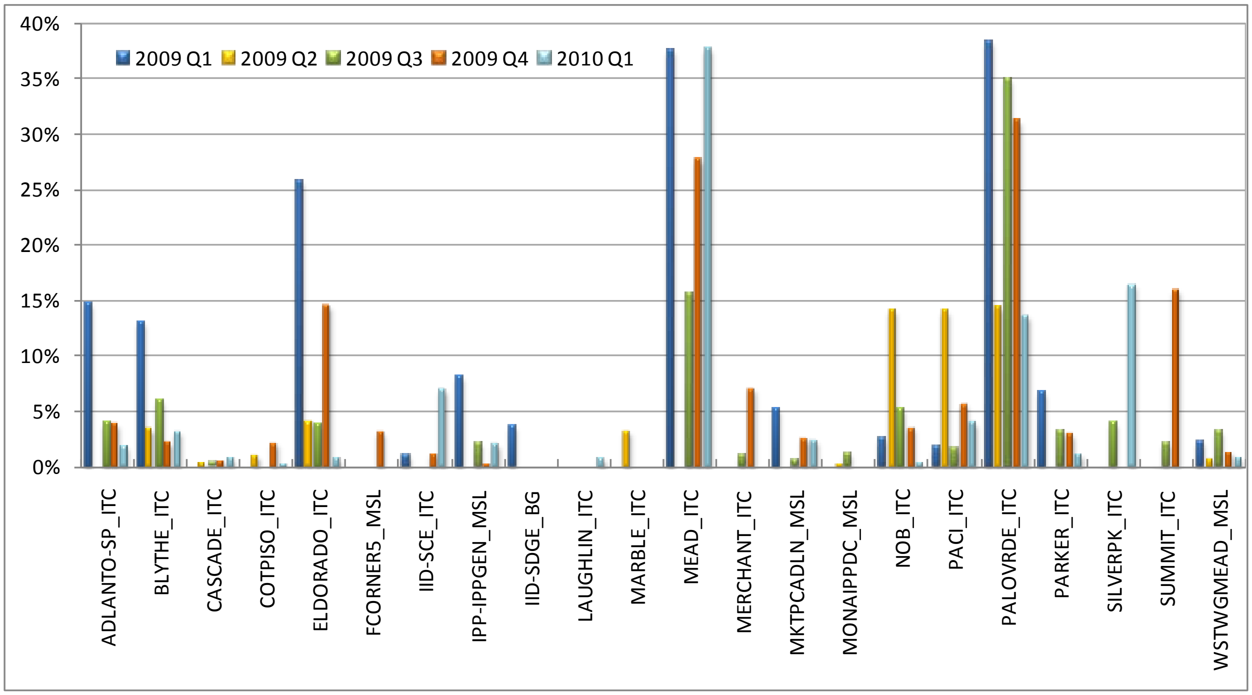
Congestion on external interfaces and scheduling limits

Figure 1.11 provides a comparison of the hours of day-ahead congestion on major inter-ties on a quarterly basis from Q1 2009 through Q1 2010. Table 1.1 provides the frequency of congestion and average shadow price on the inter-ties and scheduling limits in the day-ahead market in Q1 2010.

In this section we focus on congestion in the day-ahead market in Q1 2010. Discussion of congestion that occurred in 2009 is reviewed in the *2009 Annual Report on Market Issues and Performance*.[6] The frequency of congestion on inter-ties with other regions was significantly lower in Q1 2010 than in Q1 2009, with the exception of the Silver Peak inter-tie.

[6] *2009 Annual Report on Market Issues and Performance*, http://www.caiso.com/2777/27778a322d0f0.pdf .

Figure 1.11 Frequency of IFM congestion on major inter-ties from Q1 2009 through Q1 2010



Key trends in Table 1.1 include the following:

- The Mead inter-tie was congested 38 percent of the time in the day-ahead market in the first quarter of 2010. The congestion occurred mostly during the peak hours. The average shadow price on this inter-tie was relatively low at $5/MW. The frequency of day-ahead congestion on Mead in Q1 2010 was comparable to Q1 2009 but significantly higher than Q3 and Q4 of 2009.

- The frequency of day-ahead congestion on Palo Verde decreased in Q1 2010. During this period Palo Verde was congested 14 percent of the time, with an average shadow price of $8/MW. Scheduled work in late January increased the frequency of congestion during that period. In addition, congestion in March was influenced by several scheduled outages on Palo Verde, as well as increased demand for transmission on Palo Verde resulting from outages on North Gila to Hassayampa, Devers to Palo Verde, and Imperial Valley to North Gila 500kV.

- The Silver Peak inter-tie was congested 16 percent of the time in the day-ahead market in Q1 2010. In mid-February, scheduled work on the Miller 55kV substation limited the Silver Peak inter-tie to 0 MW in the import direction and 13 MW in the export direction. The derate lasted until the end of May 2010. The average shadow price on this inter-tie was $17/MW.

One contributing factor to the high frequency of congestion on Mead is the use of existing transmission rights by scheduling coordinators. These transmission rights allow the participant to reserve transmission on a designated path until after the hour-ahead market is run if they are not released by the participant prior to the market's running. The participant may choose to schedule power or not on the reserved transmission. The reservation reduces in the day-ahead and hour-ahead markets the amount of transmission capacity available for the market to clear bids across whether the capacity is used by the participant or not.

In the case of Mead, the limit available to the market varied with the transmission rights exercised by the participants who hold them. To the extent other participants scheduling or bidding at this inter-tie did not account for this variation in available capacity, a reduction in available capacity due to reservations from these rights could result in congestion on the inter-tie.

Table 1.1 Frequency of IFM congestion and average shadow prices of inter-ties (Q1 2010)

Name	Congestion Frequency	Avg. Shadow Price
ADLANTO-SP_ITC	2%	$3
BLYTHE_ITC	3%	$22
CASCADE_ITC	1%	$4
COTPISO_ITC	0%	$1
ELDORADO_ITC	1%	$4
IID-SCE_ITC	7%	$22
IPP-IPPGEN_MSL	2%	$23
LAUGHLIN_ITC	1%	$1
MEAD_ITC	38%	$5
MKTPCADLN_MSL	2%	$25
NOB_ITC	0.4%	$13
PACI_ITC	4%	$6
PALOVRDE_ITC	14%	$8
PARKER_ITC	1%	$21
SILVERPK_ITC	16%	$17
WSTWGMEAD_MSL	1%	$2

Congestion on internal constraints

Figure 1.12 shows the impact of congestion on specific internal constraints on average day-ahead LMPs for the three load aggregation points during the hours when congestion occurred. Constraints shown in Figure 1.12 include either the most frequently congested internal flowgates and nomograms in the day-ahead market or those that had an impact on an LMP of at least $0.70.

As shown in Figure 1.12, congestion on some constraints had a significant impact on prices in the different load aggregation points during hours of congestion. However, because the frequency of this internal congestion was very low, this had a minimal impact on overall day-ahead energy prices in Q1. Other findings include:

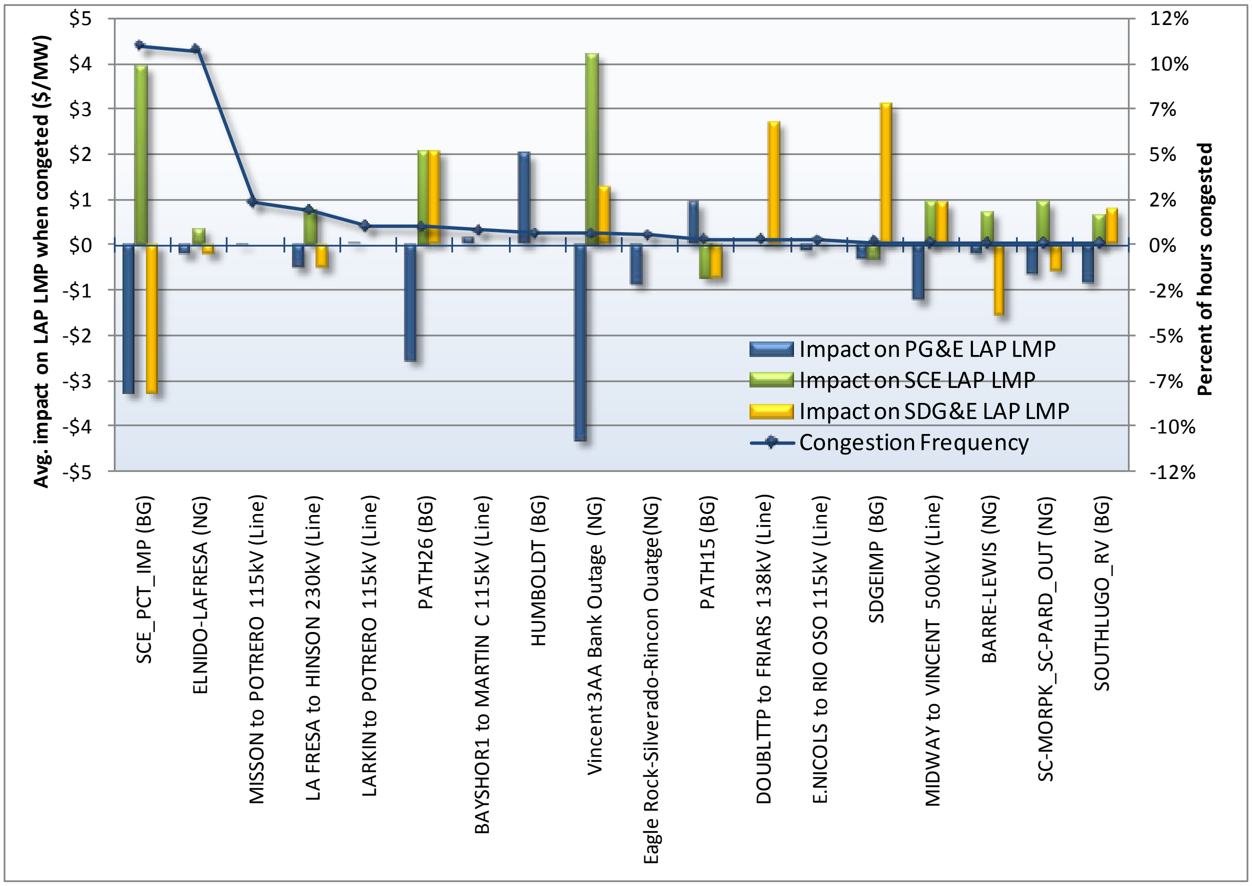
- The SCE import percent branch group limit was congested 10.5 percent of the time. This is a constraint on the percent of SCE load that is met by imports into that area.[7] The impact of this constraint on the SCE load aggregation point LMPs during hours when this constraint was binding averaged $3.93/MWh. The impact on the load aggregation point LMPs for PG&E and SDG&E was

[7] A technical bulletin was posted on December 1, 2009. See http://www.caiso.com/2479/247997c52e0f0.pdf.

negative, indicating that when this constraint was binding the price in PG&E and SDG&E areas was lower relative to both the SCE area LMP and the system marginal energy cost.

- The Vincent 3AA Bank outage had the highest impact on SCE's load aggregation point prices during hours where the constraint was binding, at $4.20/MWh. This constraint was binding less than 1 percent of hours in Q1 in the day-ahead market, so overall impact across the quarter was minimal.

Figure 1.12 Impact of congestion on internal constraints on LAP LMPs (Q1 2010)



Conforming constraint limits

Constraint limits in the market software are sometimes adjusted or conformed to account for differences in flows calculated by the market model and actual flows observed in real-time. Operators conformed constraints to manage a small number of all transmission constraints, but during a significant number of hours. Constraints tended to be conformed in the upward direction in real-time, increasing the limit on those constraints. This is typically done when the flow calculated by the market is significantly above the actual flow indicated through the energy management system (EMS). In such cases, the market is indicating a higher degree of scarcity of transmission capacity than actually exists. Grid operators will conform the constraint limit upward to more accurately reflect the available transmission capacity on the constraint. This practice avoids instances where the constraint artificially binds in the market and impacts prices when transmission was not in fact scarce.

Our analysis indicates that a total of 23 flowgates were conformed or adjusted more than 5 percent of the time in Q1 2010. Ten of these flowgates were conformed in the real-time market more than 50 percent of the time. There was strong consistency in conforming within the real-time markets (hour-ahead scheduling process and real-time dispatch) in both frequency and level of adjustment.

There was fairly infrequent constraint conforming in the day-ahead market. Operation engineers review congestion in the day-ahead market on a regular basis to indicate potential need for conforming.

Table 1.2 lists all flowgates and nomograms that were conformed in the real-time market, along with the percentage of hours that each were conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price. The statistics presented in this table are calculated only for intervals in which the conforming action moved the effective limit from the actual limit. For most of these transmission lines, the conforming level was maintained at a relatively constant level during the period in which they were conformed.

Of the 26 constraints listed in Table 1.2, 50 percent (13 constraints) were only conformed in the upward direction, to avoid congestion occurring in the market that was not actually occurring based on observed flows. Some of the major branch groups were conformed mostly downward (Path 26, Path 15, SDGE CFE import limit, SDGE import limit and Los Baños North branch group). Operators tend to conform down the operating limit of these major transmission lines to maintain an adequate reliability margin. The reliability margin ensures the flow on the grid line stays within the lines' operating limits even when sudden unpredictable changes in flows occur.

Table 1.2 shows conforming data for the real-time market and confirms that constraints were rarely congested during the time intervals that their operating limits were conformed upward. Most of the congestion occurred when downward conforming was applied, which was still very low. When ratings were conformed down, the actual real-time flows were approaching the constraint operating limit more rapidly than the market real-time flow, and in some cases even exceeded the limit. In these circumstances, Grid Operators conform the constraint limit downward to get the market to manage flows by dispatching resources to relieve the constraint at a lower limit.

Table 1.2 Real-time congestion frequency and conforming limits for flowgates (Q1 2010)

Flowgate Name	Conformed Intervals	Conformed Upward				Conformed Downward			
		Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price	Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price
SSONGS (BG)	100.0%					100.00%	85		
HUMBOLDT (BG)	98.9%	76.2%	150	0.05%	$107	22.65%	80	0.17%	$457
SDGE_CFEIMP (BG)	93.5%	1.3%	148			92.20%	94	0.14%	$280
SCE_PCT_IMP (BG)	90.6%	74.1%	106	0.52%	$199	16.52%	98	2.20%	$171
SILVERGT to MLMS3TAP 230kV (Line)	80.8%	80.8%	120						
HUMBOLDT 1 (XF)	80.8%	80.8%	110						
ORO LOMA to EL NIDO 115kV (Line)	77.2%	77.2%	110						
ELNIDO-LAFRESA (NG)	65.4%	57.0%	107	0.03%	$5	8.41%	97	0.83%	$79
MISSON to POTRERO 115kV (Line)	59.1%	59.1%	110	0.19%	$603				
BARRE-LEWIS (NG)	49.3%	49.3%	104	0.01%	$21	0.01%	32		
POTRERO (MSL)	37.1%	37.1%	100	1.54%	$525				
SDGEIMP (BG)	35.7%	0.3%	102	<0.01%	$8	35.44%	90	0.34%	$51
ALHAMTP1 to SOBRANTE 115kV (Line)	19.9%	19.9%	160						
MARTINEZ to ALHAMTP1 115kV (Line)	19.9%	19.9%	160						
VINCENT 4 _P (XF)	19.8%	19.8%	110						
MARTINEZ to ALHAMTP2 115kV (Line)	18.6%					18.63%	65	0.02%	$463
BKRSFLD to BKRSFDJ2 230kV (Line)	18.5%	18.5%	158						
PATH15 (BG)	12.8%					12.83%	86	0.51%	$23
E.NICOLS to RIO OSO 115kV (Line)	12.0%	12.0%	125	0.03%	$18				
PALERMO to E.MRY J2 115kV (Line)	11.3%	11.3%	105	<0.01%	$41				
E.MRY J2 to E.NICOLS 115kV (Line)	11.3%	11.3%	105						
VICTVL (BG)	8.8%	8.8%	115						
PATH26 (BG)	4.7%	0.6%	101	0.12%	$6	4.07%	97	0.05%	$79
LOSBANOSNORTH (BG)	4.0%					3.98%	80		
LCIENEGA to LA FRESA 230kV (Line)	3.9%	3.9%	110						
HA_NGILA (NG)	3.6%					3.58%	91		

Table 1.3 lists all flowgates and nomograms that were conformed in the day-ahead market, along with the percentage of hours that each flowgate or nomogram was conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price.

As shown in Table 1.3, only 4 constraints were conformed in the day-ahead market more than 1 percent of the time. All of these constraints were conformed down to almost 90 percent of their operating limit, mostly to sustain a safe reserve margin. The San Bernardino to Devers 230 kV line was conformed downward during the forced outage of Devers to Valley 500 kV line.

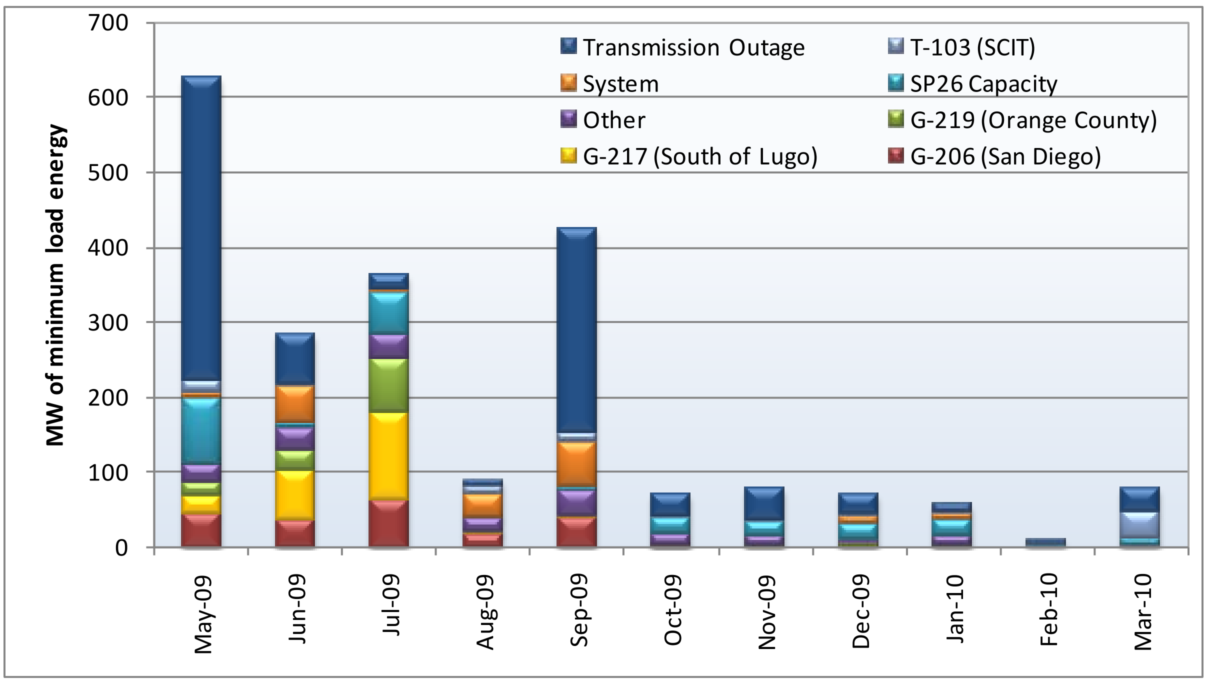
Table 1.3 Day-ahead conforming limits and congestion frequencies for flowgates for Q1 2010

Flowgate Name	Conformed Hours	Average Conformed Limit	Congested Intervals	Average Shadow Price
ELNIDO-LAFRESA (NG)	8.7%	90	3.5%	$10
SDGEIMP (BG)	1.5%	95		
SDGE_CFEIMP (BG)	1.5%	95		
SANBRDNO to DEVERS 230kV (Line)	1.1%	93		

Exceptional dispatch unit commitment

Minimum-output energy from generation committed in the day-ahead through exceptional dispatch remained relatively steady, averaging approximately 50 MW per hr across the quarter. This was less than levels seen in previous quarters. Minimum-output energy from resources committed via exceptional dispatches was particularly low in February, averaging below 10 MW per hour. The primary drivers of exceptional dispatch during the quarter were to support requirements for the Southern California Import Transmission nomogram and SP26 capacity. These requirements occurred during an annual refueling outage of the San Onofre 2 nuclear generator. In March, an additional San Onofre resource was reduced to 50 percent power for fuel conservation. An outage of the Imperial Valley-North Gila 500kV transmission corridor also required unit commitment in March to support reliability requirements. Figure 1.13 shows monthly average energy from minimum-output generation committed through exceptional dispatch.

Figure 1.13 Monthly average minimum-output energy from generation committed in day-ahead through exceptional dispatch



1.3 Ancillary Services

Ancillary service costs in the first year of the new market, April 1, 2009, to March 31, 2010, totaled about $80 million. Over $16 million, or 20 percent, of that cost occurred in the first quarter of 2010.

Figure 1.1 shows the total cost of procuring all four products by region and month over the first 12 months of the new market.[8] Key trends in the ancillary service market over this 12 month period include the following:

- Most ancillary service capacity was procured from capacity within the ISO. In the first twelve months of the new market, the cost of procuring from internal capacity was 86 percent of the total ancillary services cost.
- In the first year of the new market, 37 percent of the total ancillary services cost was from procurement of spinning reserve. The cost of procuring regulation up, regulation down and non-spinning reserve capacity were 27, 24, and 13 percent of the total ancillary service cost, respectively.
- Quarterly ancillary service costs dropped from $0.49/MWh of load served in the first quarter of 2009 to $0.31/MWh of load served in 2009.
- Cost for procuring regulation up was highest (for the twelve month period) in March 2010. This was driven by a reduction in supply of certified regulation capacity.

Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 1.15 shows the weighted average market clearing prices for each ancillary service product by month in the day-ahead market. Day-ahead prices ranged from approximately $0.50/MW to $9/MW. Key findings from Figure 1.15:

- The average day-ahead prices of regulation up in January and February were about $5.66/MW but increased to $8.41/MW in March. The tighter supply of regulation up contributed to the higher prices as well as a significant price spike in the day-ahead market on March 30 where the price was over $500/MW in the SP26 Expanded region.
- From January to March 2010, the monthly average price for regulation down increased slightly. The increase in average price for regulation down was primarily driven by the increase in opportunity cost to provide regulation down in the early morning off-peak hours.
- Spin and non-spin reserve cleared prices in the first quarter of 2010 remained low. The low clearing prices were mostly due to lower requirements corresponding to lower loads during this period.

Prices in the real-time market were low and stable, with monthly average prices for all services ranging from $0/MW to $3.50/MW. The market procures 100 percent of the forecasted requirement in the day-ahead, so volumes in the real-time market are very low.

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[8] The total cost figures from April 2009 through March 2010 account for day-ahead capacity that is unavailable in real-time and charged back to the specific unit(s) at the average of the real-time price. Resources that sell ancillary services receive the prices for all regions within which they are located. For example, a resource located in SP26 and selling spinning reserve will receive the ancillary service price for the SP26, ISO, SP26 Expanded, and ISO Expanded regions. Ancillary services have been procured from four of the 10 pre-defined regions, ISO, ISO Expanded, South of Path 26, and South of Path 26 Expanded regions, in the day-ahead and real-time pre-dispatch markets.

Figure 1.14 Ancillary service cost by region

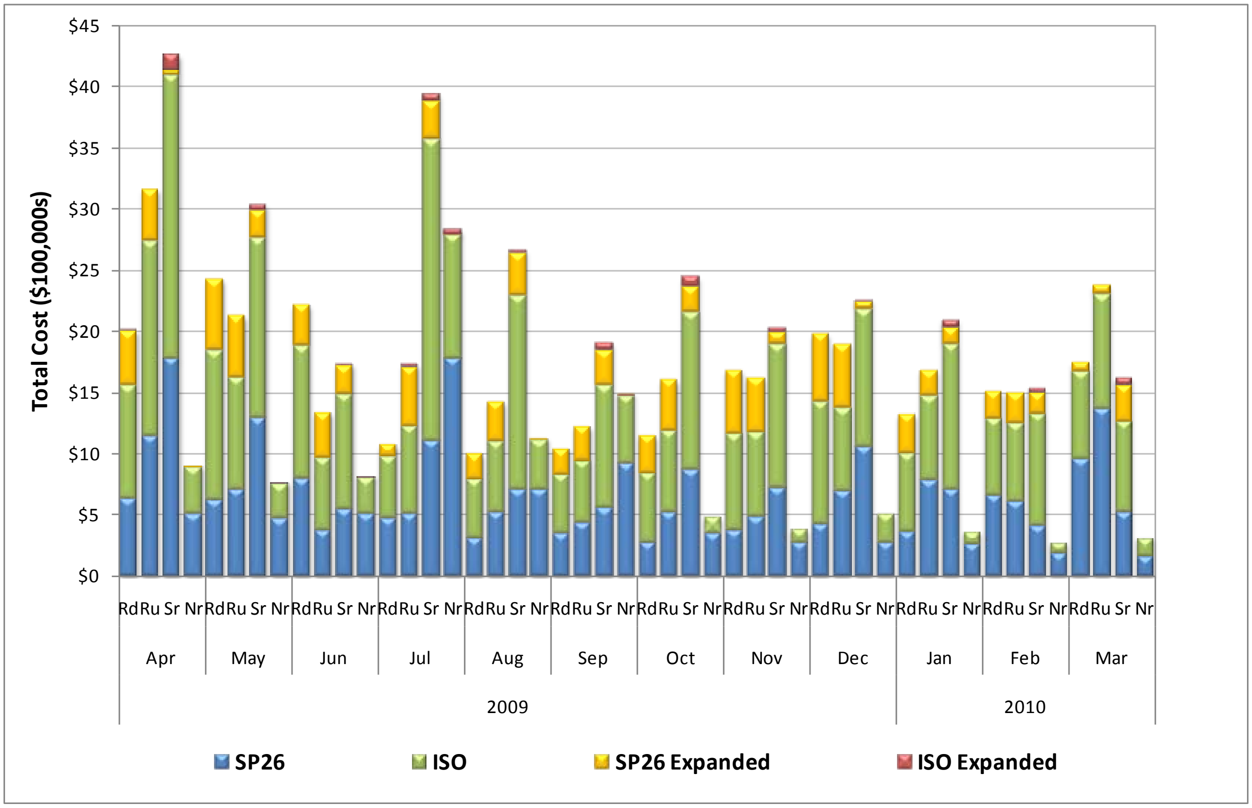
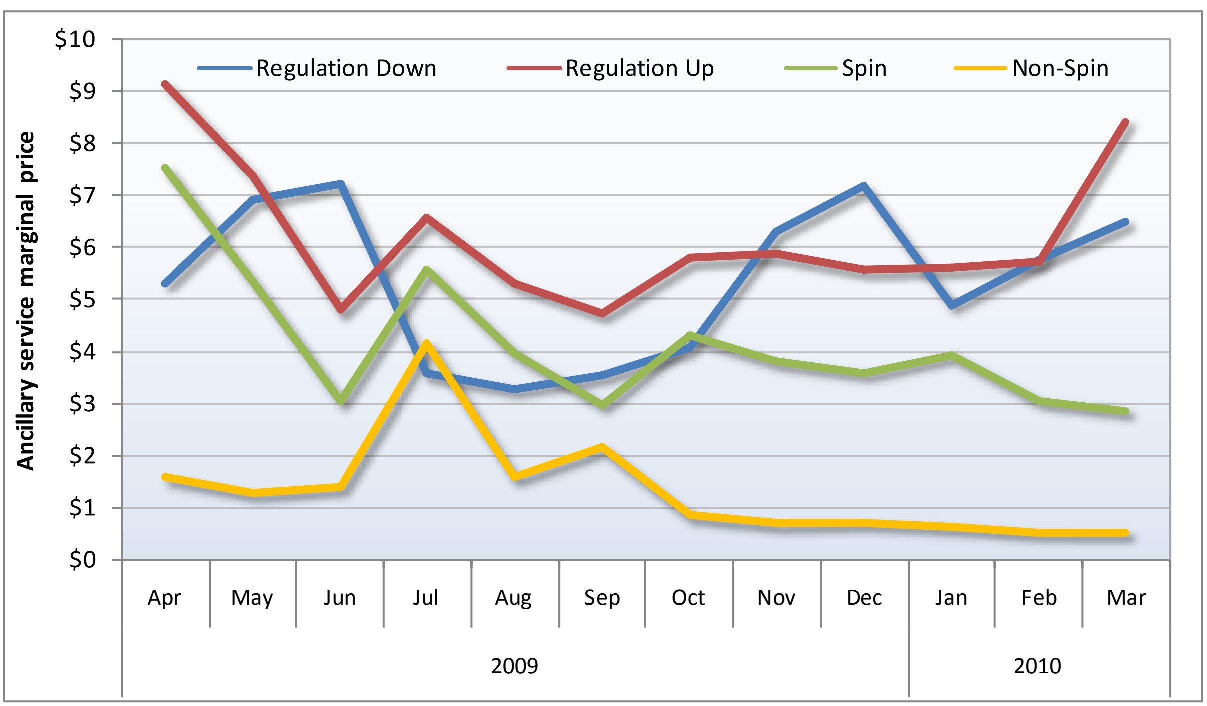


Figure 1.15 Day-ahead ancillary service market clearing prices



2 SCE Percent Import Limit

The SCE Percent Import Limit is a reliability constraint on the amount of power imported to meet load within the SCE region. This limit is intended to ensure a minimum level of generation within the SCE area in the unlikely event that the SCE area were to separate from the rest of the Western grid due to a significant drop in system-wide frequency.[9] This constraint restricts total imports into the SCE area to be less than 60 percent of SCE load, adjusted for pump load and the SCE share of San Onofre nuclear generation. The SCE Percent Import Limit is enforced as a constraint in the market optimization software in the integrated forward market, hour-ahead scheduling process, and real-time market. The constraint considers load and generation within the SCE area as well as imports into the SCE area. The limit is described in detail in a Technical Bulletin[10] issued by the ISO and is enforced pursuant to Operating Procedure E-503.

Frequency of congestion and impact on price

The SCE Percent Import Limit continued to bind more frequently in the day-ahead than in the real-time market. This can be attributed primarily to two factors. First, the hour-ahead market tends to produce lower net imports than the day-ahead. The reduction in net imports into the SCE area will lower the percent of SCE area load that is served by imports, thereby reducing the frequency that this constraint will bind in real-time compared to the day-ahead. Second, the constraint limit often requires adjustment (conforming) due to differences between actual flow and the market-calculated flow as well as intra-hour changes in load and generation that change the constraint measure.

In the day-ahead market, the limit is based on, among other things, a single forecasted load for the hour. In real time, load can change as much as 1,500 MW within the hour. This fast rate of change in load creates a very dynamic constraint limit, where the limit may change as much as 900 MW within the hour. The base limit for this constraint in real time is calculated using the hourly figure from the day-ahead, and does not automatically adjust within the hour to reflect changes in load. Because of this, it is necessary for grid operators to monitor and manage the market limit via adjustments. In hours where the actual flows are near the actual limit, there is a greater amount of operator management of the market adjusted limit When the actual flow does not approach the actual limit, the operator does not have to actively manage the limit and may set a higher conforming limit while monitoring for cases where the limit must be more actively managed.

Congestion costs attributable to the SCE Percent Import Limit were at least an order of magnitude higher in real-time than in the day-ahead market. This difference can be explained by the fact that the day-ahead market has more flexibility in resources and the amount of load that clears as well as ramping capability available to relieve the constraint. The following chart shows the frequency of binding for the SCE Percent Import Limit and associated average congestion shadow prices between November 2009 and early April 2010.

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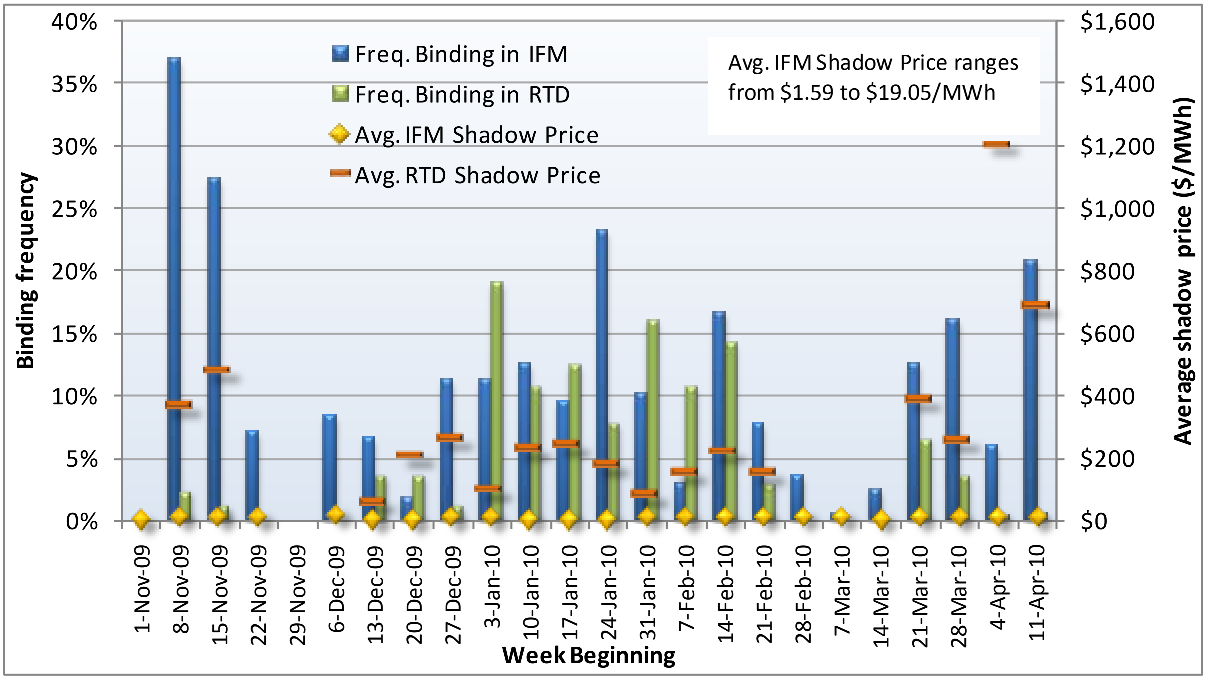
[9] It should be noted that the physical violation of a percent import limit does not itself compromise the integrity of grid assets, as would the violation of a flow constraint on a transmission line. Adherence to these limits is necessary to avoid severe load shedding in the event of a larger system-wide underfrequency event.

[10] Technical Bulletin on Import Definition and Management in Support of Underfrequency Load Shedding, December 1, 2009, http://www.caiso.com/2479/247997c52e0f0.pdf.

Figure 2.1 Weekly frequency of binding SCE percent import limit and average shadow prices



In the day-ahead market, the congestion shadow price was typically set by the difference in bid prices of the lower- and higher-cost resources and bid-in load that are redispatched to relieve the constraint. This resulted in a shadow price in the range of $1 to $20/MWh when the SCE Percent Import Limit was binding in the day-ahead market.

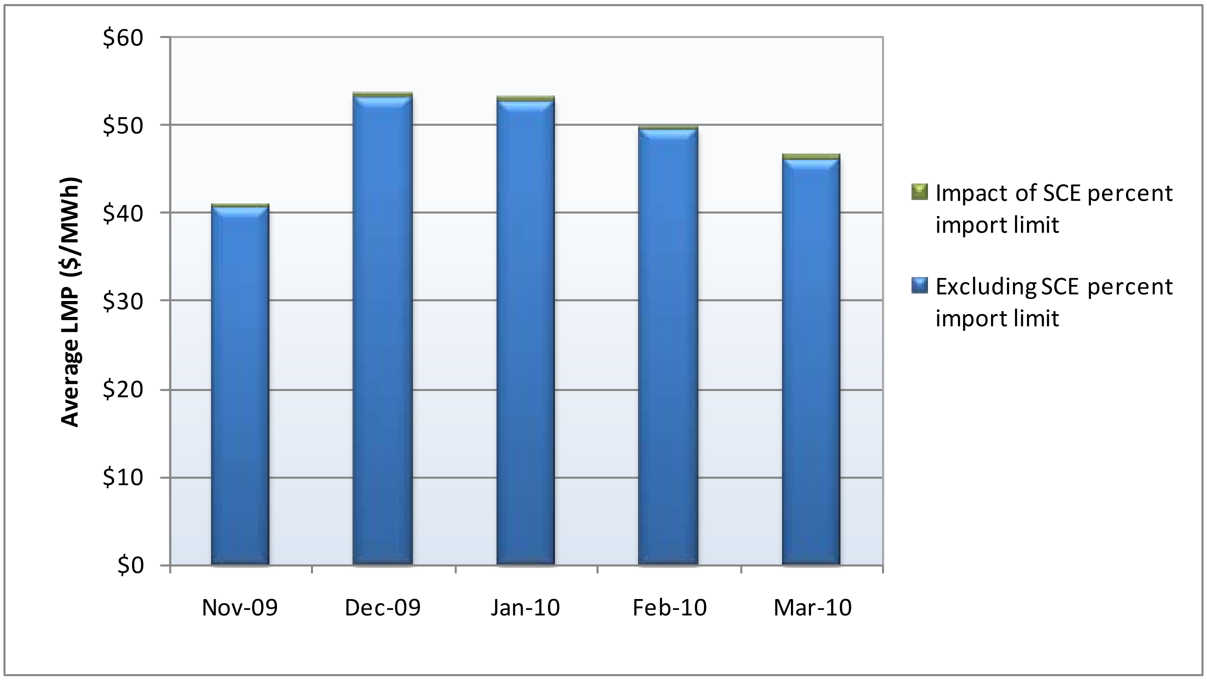
Congestion indirectly affects the price charged to load-serving entities for the power they procure in the market. The congestion shadow price indicates the increased cost imposed by the constraint to serve an additional megawatt-hour of load. This shadow price is a weighted factor in the congestion component of the LMP, which is charged to load.[11] The impact of congestion on the SCE Percent Import Limit on LMPs for the load aggregation points is shown in Figure 2.2 and Figure 2.3 below, and quantified in more detail for the day-ahead market in Figure 1.12.

The low day-ahead shadow prices associated with the SCE Percent Import Limit resulted in minimal impact on the day-ahead load aggregation point LMPs. The impact of the SCE Percent Import Limit on the monthly average LMP in the SCE load aggregation point ranged between $0.30 and $0.60/MWh. Despite the low average impact on price, congestion on this constraint has been frequent enough to significantly impact CRR revenue adequacy. Initial estimates covering the enforcement of the limit on November 11 through March 31 indicate a CRR revenue shortfall of $11 million resulting from congestion on the SCE Percent Import Limit.[12] Figure 2.2 compares the monthly average day-ahead LMP in the SCE load aggregation point, including and excluding hours in which the SCE Percent Import Limit was binding.

[11] The relationship of the shadow price and LMP congestion component is explained in detail in the Appendix of the *Annual Report on Market Issues and Performance*, http://www.caiso.com/2777/277789c42ac70.html.

[12] This figure was provided by the Market Performance group and is an estimate of the impact on CRR revenue adequacy.

Figure 2.2 Average day-ahead SCE LAP price with and without congestion on the SCE percent import limit



The real-time market has fewer supply resources available to relieve congestion, and must work within the five-minute ramp limitations of the available supply resources.[13] On heavily constrained days in March, many short-start resources were either unavailable due to outages or were unavailable for economic dispatch due to awards of contingency-only reserve. This further limited the market to only the 5-minute ramping capability of on-line internal resources.

The real-time market may be able to relieve a constraint through re-dispatch of supply resources. However, this may not be possible in some cases. When the constraint cannot be relieved through re-dispatch, the constraint may be exceeded or violated in real time. In these cases, there is a penalty price associated with that violation.[14] The penalty price is intended to provide a disincentive for the market to rely on constraint violations to reach a solution. If triggered, the penalty price for constraint violation will have an impact on energy LMPs.

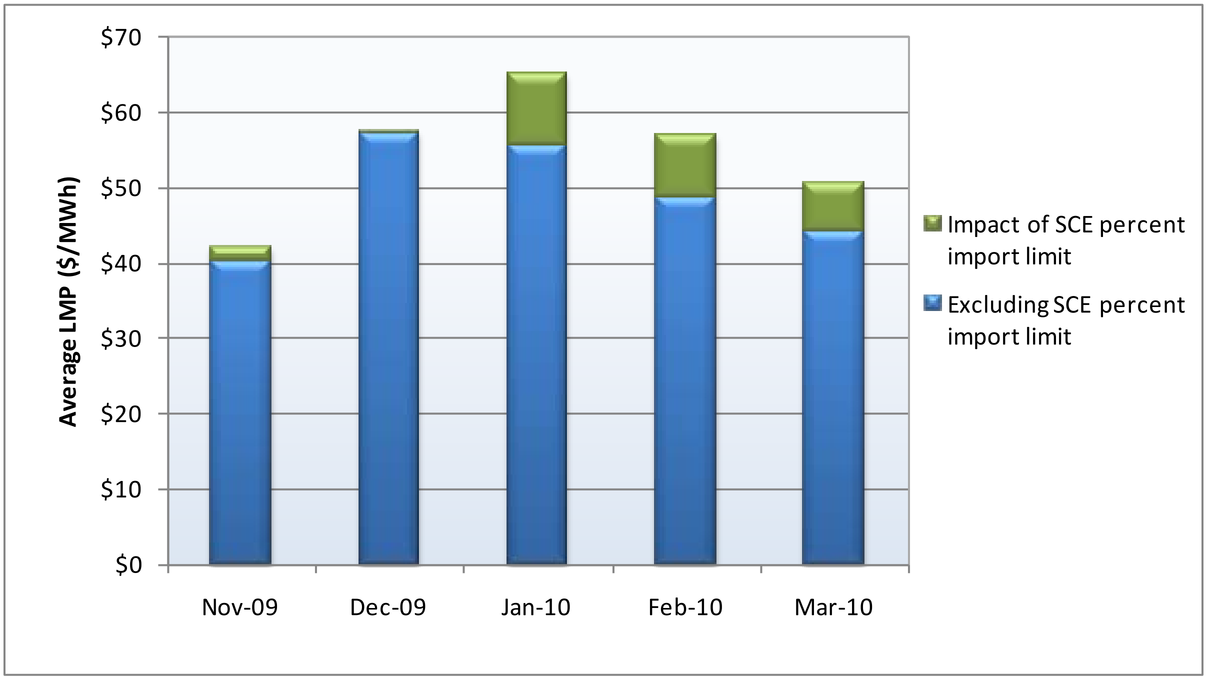
In Q1 2010, the SCE Percent Import Limit was binding fairly frequently in the real-time market. Consequently, the SCE load aggregation point LMP often featured a congestion component of approximately $500/MWh or greater in these intervals. These higher shadow prices had a larger price impact on SCE load aggregation point prices in the real-time market. The impact of the SCE Percent Import Limit on the monthly average real-time LMP in the SCE area ranged between $6.30 and

[13] Some mid- to long-start resources would not be available in real-time if they were not already committed and running that day, and the 5-minute imbalance market is very limited in the amount of import resources that can be dispatched.

[14] The penalty price for constraint violation was $500/MW (equal to the energy bid cap) through the first quarter of 2010 and was increased to $750/MW on April 1, 2010, along with the energy bid cap.

$9.50/MWh in Q1. Figure 2.3 compares the monthly average day-ahead LMP in the SCE area, including and excluding hours in which the SCE Percent Import Limit was binding.

Figure 2.3 Average real-time SCE LAP price with and without congestion on the SCE percent import limit



Manual conforming of the SCE Percent Import Limit

This section provides an analysis of the ISO's conforming practices with respect to the SCE Percent Import Limit. Conforming is the practice of manually adjusting constraint limits observed by the market to correct for discrepancies between modeled limits and flows and actual limits and flows. The purpose of this practice is to keep the market aware of transmission availability in cases where the market calculation and actual flow deviate so that the market will dispatch and price most efficiently. Constraint conforming typically results in either (a) relieving congestion in the market that should not have existed due to flow discrepancies or (b) inducing congestion in the market to force re-dispatch of resources to keep actual flows below actual constraint limits.

Analysis by DMM presented in this section indicates that manual adjustments made to conform market limits were generally consistent with the observed discrepancies between market and physical flows. However, conforming is an imperfect manual solution to the problem of modeling inaccuracies.[15]

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[15] One reason the real-time limit may be conformed is the intra-hour change in load in real time compared to the hourly load forecast (and consequent constraint limit) from the day-ahead market. The day-ahead load forecast may be quite close to the actual load across the hour in real-time. However, during sharp ramp hours the load in real time may ramp up two to three thousand megawatts. This changes the constraint limit – as load changes intra-hour the amount of imported power can increase as well (depending on changes in the internal generation levels). In this circumstance, the limit may be increasing

Manually conforming a constraint limit can be imprecise. The accuracy of this action depends on the timeliness and accuracy of the information used to determine the need for, and magnitude of, an adjustment to the limit. Discrepancy between actual physical flow and market calculated flow, and abrupt changes in either load or inter-tie flow, can cause the market model to be imprecise. Abrupt changes are difficult to adjust for with manual conforming of the constraint limit. The ISO must manage the limit in the market such that violations of the market constraint coincide with violations of the physical constraint as closely as possible. In the case where actual physical flow is (materially) below the market calculated flow, the ISO manually selects an adjusted value for the market limit that is above the current market calculated flow. This allows the market to clear the flow on that constraint at a higher level and avoid triggering a congestion price signaling scarcity on the constraint where there is none.

The default (or *un-conformed*) limit for the SCE Percent Import Limit is calculated one day in advance of operation. This un-conformed forecast limit is defined to be 60 percent of the ISO's forecast of SCE load, adjusted for load from pumps and generation from the San Onofre nuclear plant. Adjustments to this limit are applied in the real-time market to account for changes in the factors that determine the limit in the day-ahead. The market considers the constraint binding, and calculates a shadow price, whenever its calculation of the flow is at or above the conformed limit.

Manual conforming of the SCE Percent Import Limit was fairly frequent in late 2009 and Q1 2010, and increased significantly in March and April 2010. The constraint is predominantly conformed upward, indicating the real-time flow calculated by the market is often (significantly) above the actual physical flow and the market flow is approaching the (un-conformed) limit. If not corrected, this would result in congestion on the SCE Percent Import Limit when the constraint was not binding based on physical flows. This *false congestion* would increase prices in the SCE load aggregation point area.

Figure 2.4 shows the daily average conforming percentage with daily average day-ahead and real-time shadow prices for the SCE Percent Import Limit from January through late April 2010. Shadow prices exist only when the constraint is binding in the hour-ahead scheduling process (HASP) or 5-minute real-time dispatch (RTD).

Through most of February, the SCE Percent Import Limit was conformed intermittently in real-time, usually in the downward direction. Starting in late February, conforming in real-time was generally upward and not adjusted as frequently from day-to-day. The conforming adjustment remained at 110 percent of the day-ahead limit from February 28 until March 23. On April 4, the conforming adjustment increased to 130 percent, and then was reduced again to 120 percent for much of the remainder of April.

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beyond what is provided in the real-time market. As imports increase relative to internal generation, the market may see the constraint bind intra-hour when in fact the constraint limit should be higher as a result of the increased load. In this circumstance grid operators will conform the constraint upward. Another potential reason the real-time limit was conformed is to adjust for changes in the conditions used in the day-ahead to establish the limit: forecast load, pump load, and scheduled generation from San Onofre. DMM evaluated the relationship between the real-time conforming practice and changes in the load forecast for the SCE area between day-ahead and real-time, and did not find a significant correlation.

Figure 2.4 Weekly average shadow prices and manual conforming of the SCE Percent Import Limit in the hour-ahead and real-time market

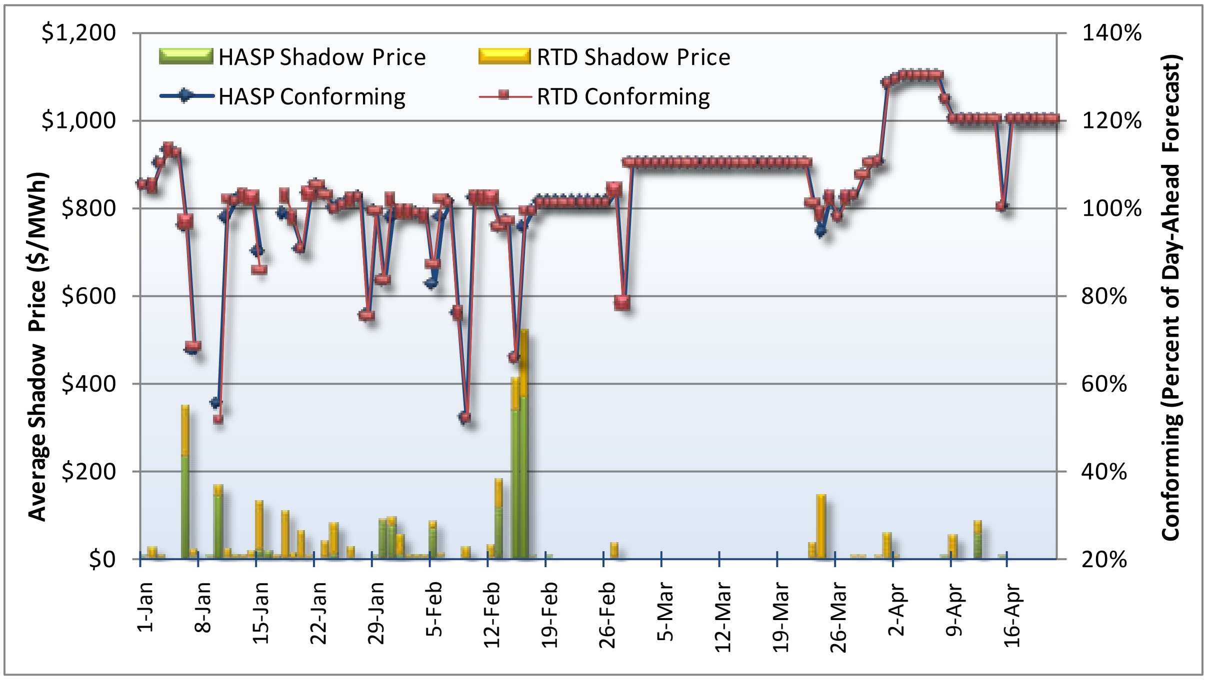


Figure 2.5 and Figure 2.6 show three key measures that can be used to assess the impact that upward conforming of this constraint that occurred beginning in March had on the frequency of congestion and congestion prices in the real-time market. These series are all represented on the left-hand axis as a percent of the applicable limit, normalized to zero (i.e., a zero value indicates that the flow equals the limit).

- The blue series shows the *physical import ratio*, or the actual physical imports as a percent of the actual physical limit.
- The green series shows the un-conformed *market import ratio*, or market imports as a percent of the un-conformed market limit.
- The red series shows the conformed *market import ratio, or* market imports as a percent of the conformed market limit.
- The purple line plotted on the right-hand axis represents the degree to which the constraint was conformed during this period.

Figure 2.5 shows the physical, estimated conformed market, and estimated un-conformed market import-limit ratios for January 5 through 11.[16]

[16] Market import flows were not saved as output from the software for analysis prior to trade date April 1, 2010. As a proxy, this analysis used base flows saved by the network application. Base flows are the ex-ante values that the ISO uses for conforming, and are provided as output whenever they are at least 85% of the conformed binding limit. DMM has verified that base flows were usually within 10% of the conformed limit when the limit was binding. Since April 1, 2010, the market software

- The period illustrated in Figure 2.5 indicates that the practice of conforming averted false congestion in many hours, and may have prevented congestion from occurring in the market when the physical limit may have been exceeded in only a few hours. However, the manual process of constraint conforming is by nature not an exact science and is susceptible to error and/or inaccuracy.

- On January 6 and 7, conforming of the market import limit was in the downward direction. This caused the market import to be higher relative to the import limit. As can be seen from the chart, this conforming action was appropriate, as the conformed limit ratio (red) was closer to the physical limit ratio (blue) than was the un-conformed limit ratio (green).

- During the early morning low-load periods of January 10 and 11, conforming was in the upward direction; the ISO increased the market limit approximately 5 percent above the day-ahead forecast limit. This had the effect of lowering the ratio of the market-calculated import to the market import limit. However, during this period, the level of physical imports was actually above the import limit. In this instance, it appears conforming in the opposite direction would have been appropriate. The relative difference between the market import and the conformed limit (red) was actually farther from the relative difference between the physical import and limit (blue) than was the relative difference between the market import and the unconformed limit (green). This is indicative of the potential occasional error in a manual process such as conforming.

Figure 2.6 shows similar analysis for the period from April 1 through 14.[17]

- As shown by the blue series, actual imports exceeded this constraint during a relatively small portion of intervals during this two week period.

has preserved final import flows whenever they are at least 85 percent of the conformed binding limit. These data provide a basis for more accurate analysis of actual versus market flows and the impact of the practice of conforming constraints.

[17] No market import data are shown between April 4 and 6 because market-calculated imports were less than 85 percent of the limit. When market flows are less than 85 percent of the market limit, flow data are not saved by the market software. Because physical imports were also below the physical limit at this time, the market properly identified the absence of congestion.

Figure 2.5 Real-time conforming percent and the relationship between real-time flows and limits on the physical grid and the market for January 5 - 11, 2010[18]

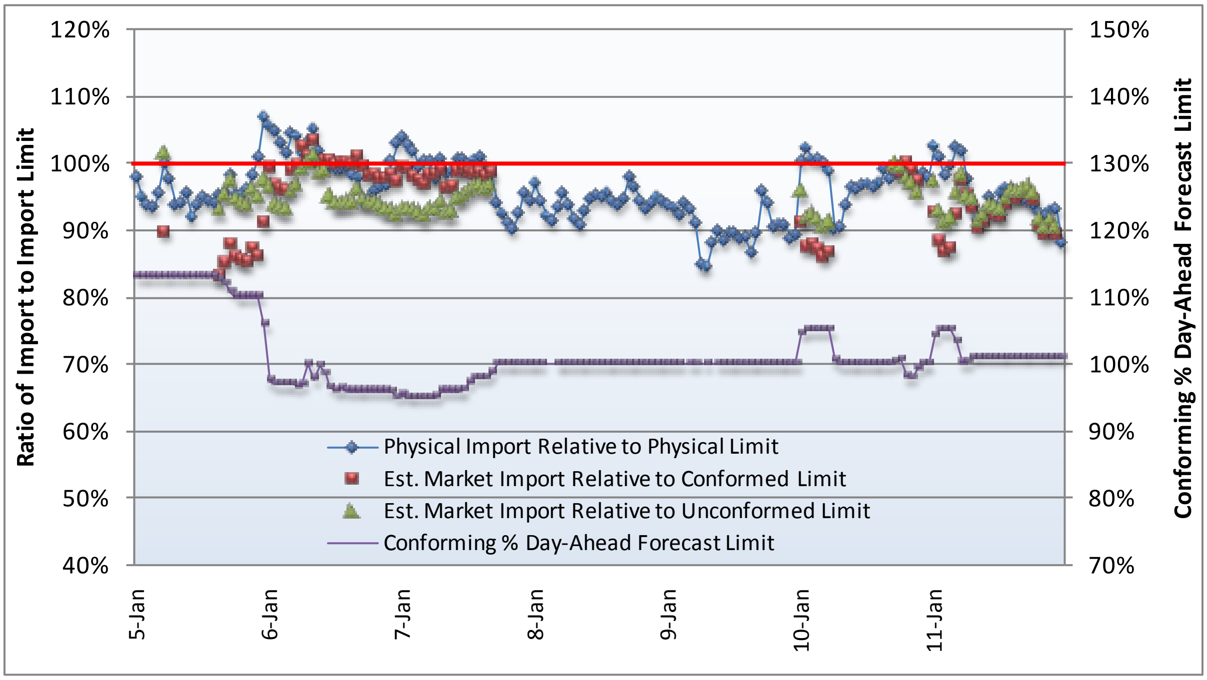
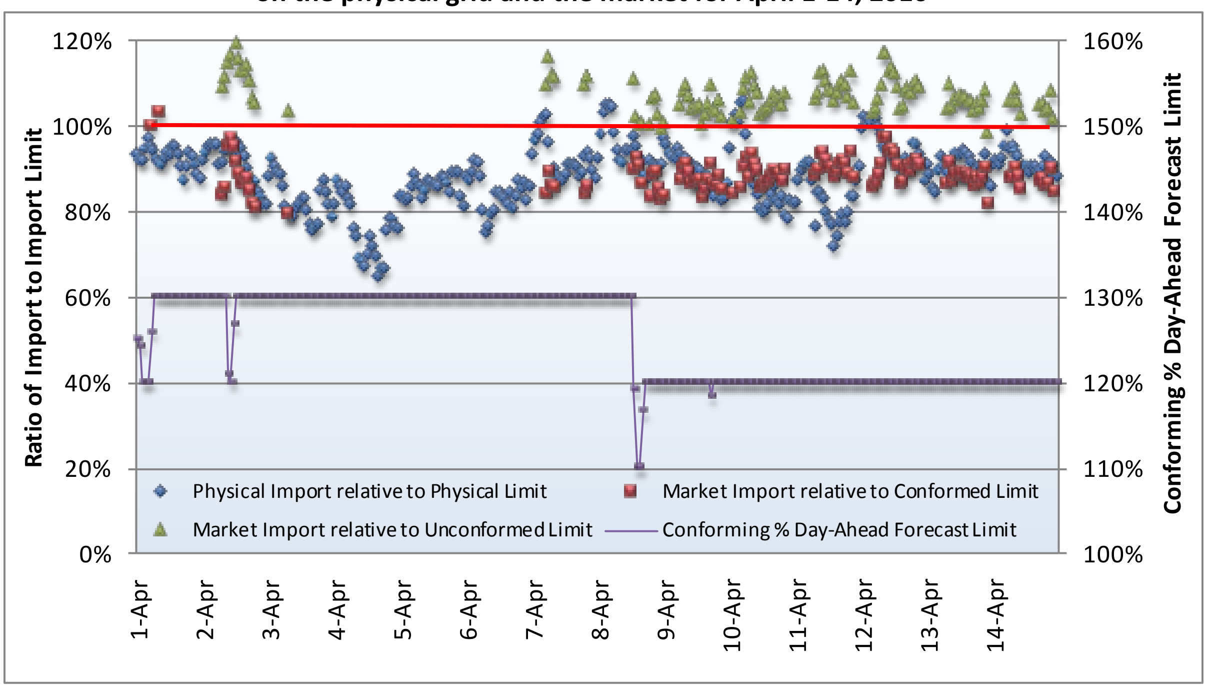


Figure 2.6 Real-time conforming percent and the relationship between real-time flows and limits on the physical grid and the market for April 1-14, 2010[19]



[18] Ibid.

[19] Physical difference calculated as (physical import – physical limit)/physical limit. Conformed market difference calculated as (market import – conformed market limit)/conformed market limit. Unconformed market difference calculated as (market import – unconformed market limit)/unconformed market limit. Conformed percentage equal to (conformed market limit – day-ahead forecast limit)/day-ahead forecast limit.

- As shown the by the green series in Figure 2.6 (representing market imports as a percent of the un-conformed market limit), market imports during this period were often above the un-conformed limit for this constraint. If the constraint had not been conformed upwards during these intervals, congestion would have occurred in the real-time market. Since actual physical flows (blue) were lower than the physical limit for most of this period, conforming prevented the market from binding the import limit when this constraint was not physically binding.
- The red series in Figure 2.6 shows that that conforming aligned the market import ratio more closely to the physical import ratio. The conformed market import ratio and physical import ratio during this period were almost always lower than 100 percent, whereas the un-conformed market ratio was usually above 100 percent. Consequently, the market showed no congestion in cases where the physical flow (blue) was not binding. Without conforming, the market would have improperly imputed a congestion price for the limit whenever the un-conformed market ratio (green) exceeded 100 percent.
- The purple line plotted on the right-hand axis represents the degree to which the constraint was conformed during this period. As shown in Figure 2.6, the import limit was conformed to about 130 percent of the day-ahead forecast limit from April 1 to 8, and was conformed to about 120 percent from April 8 to April 14.

Some stakeholders have expressed concern that the practice of conforming transmission constraints is not transparent enough to provide confidence that the process is achieving the desired goals and that accurate price signals are being produced by the market. DMM's analysis of the SCE Percent Import Limit for a sample week in January and the first two weeks of April indicates that the practice of conforming constraints has generally been working as intended in this circumstance.

However, DMM believes this type of analysis and development of tools for improving constraint conforming is important to further refine the practice and improve the outcomes. The ISO has developed a tool to provide a more accurate calculation that may be subject to testing in the upcoming months.

Challenges exist for more systematic automated analysis of the effectiveness and impact of constraint conforming. For example, the market software does not currently provide market flow data in intervals for which that flow is less than 85 percent of the conformed limit. Further, the data for actual flow is not integrated with the data warehouse that houses the market data and must be extracted manually one day at a time.

Southern California inter-tie separation limit

The ISO has proposed replacing the SCE Percent Import Limit and the unmodeled SDG&E Percent Import Limit with a single limit to cover all imports into Southern California. This new limit is known as the Southern California Inter-tie Separation Limit (SCISL). The ISO has proposed this unified import limit that models the SCE and SDG&E systems as remaining as one island, rather than splitting into two islands, in an extreme under-frequency event. This more accurately models the physical flow that would occur in such an event. The ISO is working with the affected transmission owners to form a consensus on this issue, and is responsible for enforcing the constraints that the transmission owners deem necessary for grid reliability.

3 Minimum online constraints in the day-ahead market

Starting February 5, 2010, the ISO began enforcing the G-217 and G-219 operating procedures in the day-ahead market using a newly created market model variable referred to as a *minimum online commitment* constraint (or MOC). Prior to this date, the ISO enforced these operating procedures through exceptional dispatch and, later, through an energy-based nomogram enforced only in the residual unit commitment process of the day-ahead market. This section describes these operating procedures and the methods used in enforcing them since the inception of the new market, and presents an analysis that DMM completed to assess the impact the enforcement of the operating procedures had on the day-ahead market.

Description of G-217 and G-219 operating procedures

The G-217 and G-219 operating procedures provide minimum capacity commitment requirements of predetermined localized generators used in mitigating potential thermal overloads and voltage issues in SCE's service area.[20] The G-217 operating procedure provides minimum capacity commitment guidelines for the South-of-Lugo area of the SCE service territory. The G-219 provides similar guidelines for the Orange County area of the SCE service territory. These operating procedures specify the minimum amount of capacity required to be committed, based on the load levels in the area, to maintain reliability on the local system.[21]

Past and present methods of enforcement

During the new market operation starting April 1, 2009, the G-217 and G-219 operating procedures have been enforced using three different methods. Table 3.1 presents the primary method of enforcement and the time frames each was used in meeting the G-217 and G-219 operating procedures. As shown in Table 3.1, at the beginning of the new market, the G-217 and G-219 operating procedures were enforced primarily by exceptional dispatch. Starting on July 27, 2009, the operating procedures were primarily met through enforcement of an energy-based nomogram modeled in the residual unit commitment process of the day-ahead market. Finally, since February 5, 2010, the constraints have been met primarily by enforcement of a minimum online commitment constraint enforced in the day-ahead market.[22]

[20] For more information, please refer to the Minimum Online Commitment Constraint technical bulletin located at the following link: http://www.caiso.com/271d/271dedc860760.pdf.

[21] Details of the G-217 and G-219 operating procedures are not publicly available due to security reasons.

[22] Since the implementation of G-217 and G-219 operating procedures into the day-ahead market, load levels in SCE have not warranted the G-217 minimum online commitment to be modeled in the market software.

Table 3.1 G-217 and G-219 methods of enforcement

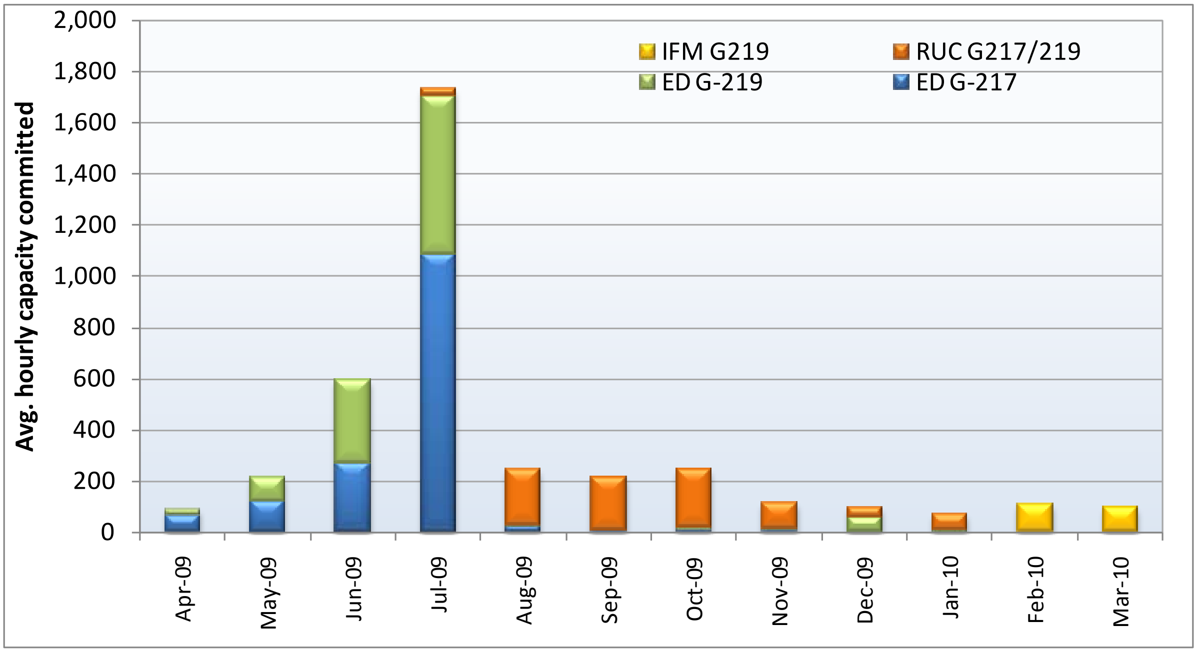
Date Range	Enforcement Method
April 1, 2009 to July 26, 2009	Exceptional Dispatch
July 27, 2009 to February 4, 2010	RUC Energy Nomogram Constraint
February 5, 2010 -	IFM Minimum Online Capacity Constraint

Figure 3.1 illustrates the average daily capacity committed for the G-217 and G-219 operating procedure by month by enforcement method. Because each method enforced the G-217 and G-219 operating procedures in a different approach, it may be misleading to simply compare the numbers depicted in Figure 3.1 without an understanding of these differences. The following points describe the results of each enforcement method shown in Figure 3.1:

- ***Exceptional dispatch period –*** The reported average hourly capacity committed for G-217 and G-219 during the "exceptional dispatch period" represents the capacity that units were exceptionally dispatched in the day-ahead market for these specific operating procedures.
- ***RUC nomogram period –*** The reported average hourly capacity committed for G-217 and G-219 during the "RUC nomogram period" reflects only commitment of units during the residual unit commitment process. For example, consider a G-219 unit that was committed during the day-ahead market process for the first 22 hours of a day, and committed further for the final two hours of the day during the residual unit commitment process to meet the G-219 energy-based nomogram constraint. In this example, only the commitment capacity for the two incremental commitments in residual unit commitment are counted.
- ***IFM MOC period –*** The reported average hourly capacity committed for G-219 during the "IFM MOC period" reflects the amount of capacity committed during the day-ahead market process to meet the day-ahead enforced G-219 minimum online commitment.[23] This method differs from the method for the "RUC nomogram period" because it is not easily discernable if the unit would have been committed in the day-ahead market without the day-ahead minimum online commitment constraint enforced in the market model. Consequently, for this period, all hours were averaged where the day-ahead minimum online commitment was enforced.

[23] See footnote 22.

Figure 3.1 G-217 and G-219 average capacity committed by enforcement method

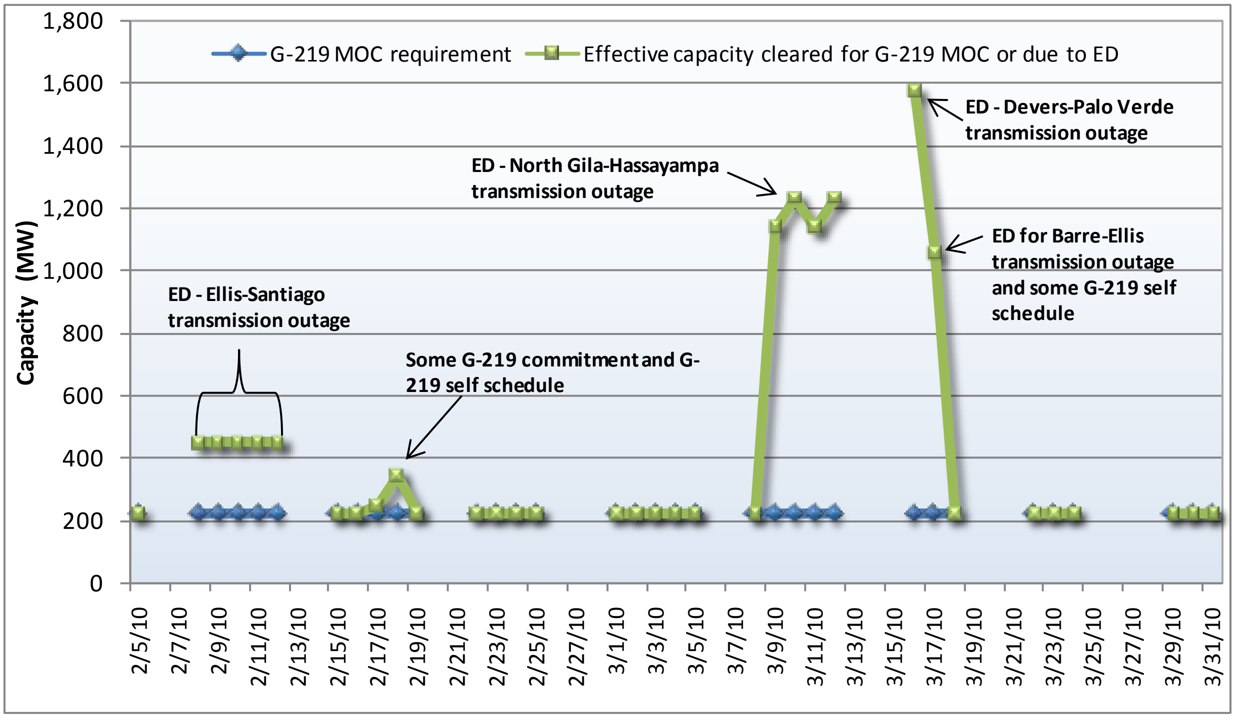


While the use of the first two methods met the requirements of the G-217 and G-219 operating procedures in day-to-day operations, these were not optimal methods as prices settled in the day-ahead market did not reflect the commitment of additional generation due to post-market exceptional dispatch or those committed due to the energy-based nomogram in residual unit commitment. Further, the enforcement of energy-based constraints in residual unit commitment could potentially cause over-procurement of energy when the schedules of the units committed because of the energy-based constraint in residual unit commitment are combined with total day-ahead market schedules.

The ISO's latest approach to meeting the requirements of G-217 and G-219 through a minimum online commitment constraint that is enforced in all day-ahead market passes (market power mitigation, integrated forward market, and residual unit commitment) is a major enhancement that allows energy and ancillary services to be settled consistently across each day-ahead market pass with each pass utilizing the same set of constraints.

Figure 3.2 shows the daily maximum G-219 capacity committed (green line) during peak hours to meet the G-219 minimum online commitment (the blue line) as modeled in the day-ahead market from February 5, 2010, through March 31, 2010. On days where transmission outages did not call for exceptional dispatch, the G-219 minimum online commitment constraint was always met. Missing dates reflect days that the G-219 was not enforced.

Figure 3.2 IFM G-219 MOC requirement and commitment (daily maximum of peak hours)



Analysis of minimum online commitment constraint in the day-ahead market

To assess the impact of enforcing the minimum online commitment in the day-ahead market, DMM performed an analysis of nine sample dates between February 5, 2010, and March 31, 2010, where the day-ahead minimum online commitment for G-219 was enforced.[24] For each of these nine trade dates, DMM re-ran the day-ahead market software for two scenarios. The first case was simply a rerun of the market using the original market settings and inputs, which served as a baseline for comparison.[25] For the second case, the minimum online commitment requirement was removed from the market requirement's constraint list, and the day-ahead market was rerun. Output from these two cases were then compared to assess the impact of the G-219 minimum online commitment on prices in each load aggregation point and unit commitments.

Results of the analysis of the nine sample days are summarized in Table 3.2. The following points detail the key findings of this analysis:

- ***Prices decreased with G-219 MOC enforced –*** In eight of the nine trade dates analyzed, daily average load aggregation point prices with the minimum online commitment enforced in the day-ahead were 1 to 3 percent lower than those in the scenario without the minimum online

[24] See footnote 22.

[25] Because versioning of software can have an impact on older trade dates being analyzed, rerunning each sample date with original market inputs and comparing the results to the actual market results shows if there is a possible problem with vintage of the Save Case and versioning of the software. In instances where this base rerun of the market shows significant differences compared to original market results, the trade date was excluded from the analysis.

commitment enforced in the day-ahead.[26] This finding is due to the fact that the minimum online commitment process commits units into the day-ahead market that may not necessarily have been committed, shifting the supply curve to the right, and allowing a lower priced unit to set the marginal price.

- ***G-219 MOC not met without enforcement in market model –*** Results show that on each of the nine days analyzed, sufficient capacity effective at meeting G-219 units would not have been committed and the constraint would not have been met without the G-219 minimum online commitment enforced.
- ***G-219 MOC never binding –*** The G-219 minimum online commitment has been met through commitment by the market software on all days that it has been enforced. On days that it was not enforced, load conditions did not warrant modeling of the constraint in the market model.
- ***No over-commitment of units due to G-219 MOC –*** This analysis shows no over-commitment of units due to the G-219 minimum online commitment constraint. On a few occasions, a unit effective at meeting G-219 requirements was self-scheduled in the day-ahead market. However, the effective capacity of the unit was less than the minimum online commitment requirement. Under this circumstance the market software committed an additional G-219 unit to meet the requirement, exceeding the capacity requirement by a large amount.
- ***Energy above minimum load –*** Units committed to meet the G-219 minimum online commitment were dispatched well above minimum load during each of the nine cases analyzed where the minimum online commitment would not have been met without enforcement in the day-ahead market. Figure 3.3 shows the average hourly dispatch as a percent of maximum capacity for the sample days where the units were committed in the day-ahead market solely to meet the G-219 constraint. This provides an indication that incorporating G-219 requirements in the day-ahead energy market increases market efficiency by allowing these units to also be scheduled to provide energy in the day-ahead market. This also increases potential revenues for these generating units and can be expected to reduce bid cost recovery payments compared to the prior approach of committing units needed to meet these requirements in the residual unit commitment process.

[26] In one of the nine trade dates analyzed (March 24), daily average load aggregation point prices increased marginally by 0.7 to 1.7 percent with the minimum online commitment constraint enforced in the day-ahead. On this particular day, the case without the G-219 minimum online commitment constraint enforced showed that a G-219 unit was economically committed into the market and had a similar energy schedule to the case with the constraint enforced. In this circumstance, the difference in prices could be considered within the model's "margin of error." Such results can be attributed to the fact that relatively small changes in day-ahead market input parameters can cause the software to take a different "search path," which can result in different solutions at the point that the minimum MIP gap requirements are met and the software stops.

Table 3.2 Impact of G-219 MOC enforcement in day-ahead energy market

DA TRADE DATE	LAP	AVG LMP	AVG DIFF (w/G219 MOC)	% DIFF (w/G219 MOC)	MOC MET WITHOUT MOC ENFORCED?	Unit Dispatched Above PMin?	Notes
2/24/2010	PGAE	45.25	-0.34	-0.8%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	44.39	-0.43	-1.0%			
	SDGE	44.53	-0.44	-1.0%			
2/25/2010	PGAE	42.46	-0.52	-1.2%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	41.04	-0.55	-1.3%			
	SDGE	41.21	-0.57	-1.4%			
3/1/2010	PGAE	40.90	-0.47	-1.1%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	41.36	-0.98	-2.4%			
	SDGE	41.54	-0.98	-2.4%			
3/4/2010	PGAE	40.13	-0.35	-0.9%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	39.18	-0.48	-1.2%			
	SDGE	39.49	-0.49	-1.2%			
3/5/2010	PGAE	43.08	-0.41	-1.0%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	41.77	-0.59	-1.4%			
	SDGE	41.85	-0.61	-1.5%			
3/22/2010	PGAE	41.12	-0.57	-1.4%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	40.95	-0.74	-1.8%			
	SDGE	41.32	-0.74	-1.8%			
3/23/2010	PGAE	41.68	-0.54	-1.3%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	42.01	-1.47	-3.5%			
	SDGE	42.48	-0.78	-1.8%			
3/24/2010	PGAE	38.23	0.20	0.5%	No	Yes	G-219 unit was committed for 23 hours of the day even when MOC was not enforced.
	SCE	43.90	0.50	1.1%			
	SDGE	39.73	0.68	1.7%			
3/30/2010	PGAE	35.87	-0.32	-0.9%	No	Yes	No effective units committed when the G219 MOC Requirement is not enforced.
	SCE	35.97	-0.44	-1.2%			
	SDGE	36.58	-0.44	-1.2%			

Figure 3.3 Average hourly energy dispatch as a percent of maximum capacity for units committed due to G-219 MOC