California ISO
Your Link to Power

California Independent
System Operator Corporation

July 30, 2009

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

Re: California Independent System Operator Corporation
Docket Nos. ER06-615-___, ER09-213-___, ER09-240-___, and ER09-241-____ (Not Consolidated)

ISO Quarterly Reports on Market Performance

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO")[1] hereby submits in these proceedings two quarterly reports: (1) the Post-Implementation Report prepared by the ISO's Department of Market Services and analyzing the performance of the ISO's new market[2] during the first three months of market operations (from April 1, 2009, through June 30, 2009) ('market services quarterly report"); and (2) the ISO's Department of Market Monitoring ("DMM") Quarterly Report on MRTU Design Issues analyzing aspects of the performance of the ISO's new market during the April 1-June 30 time period that are not covered by the market services quarterly report ("DMM quarterly report").[3]

As explained further below and in the attached reports, the ISO quarterly reports comply with the directive in the September 21, 2006, order in Docket Nos. ER06-615-000, *et al.* that the ISO, for the first year after implementation of the ISO's new market, "commence filing post-implementation performance reports on a quarterly basis within 30 days of the end of each calendar quarter,"[4] and the ISO quarterly reports also satisfy the other Commission directives on

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[1] The ISO is also sometimes referred to as the CAISO. Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definitions Supplement, Appendix A to the CAISO Tariff.

[2] The ISO's new market is also sometimes referred to as the Market Redesign and Technology Upgrade or MRTU. The ISO's new market became effective on March 31, 2009, for the Day-Ahead Market for the April 1, 2009, trading day.

[3] The market services quarterly report and the DMM quarterly report are referred to together as the "ISO quarterly reports."

[4] *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 1417 (2006) ("September 2006 Order").

quarterly reporting issued in the September 2006 Order, subsequent Commission orders as noted, and ISO requirements and commitments.

I. Overview of the Market Services Quarterly Report

The market services quarterly report addresses a number of different matters regarding the performance of the ISO's new market during the April 1-June 30 time period. These matters include the following:

- MRTU performance and characteristics, including discussion of loads, natural gas prices, inventories, and bilateral electricity prices;
- Market performance metrics, including discussion of the Day-Ahead Markets, Real-Time Markets, Residual Unit Commitments, Ancillary Services markets, Integrated Forward Market congestion, the post-Day-Ahead perfect hedge, and Exceptional Dispatch;
- The cost of the perfect hedge;
- Compliance with North American Electric Reliability Corporation ("NERC") Reliability Standards;
- Assessment of Ancillary Service control;
- Status of Business Practice Manual proposed revision requests;
- Bilateral transfers of Existing Contract import capability;
- Aggregate data on interim scheduling charges;
- Deferred functionality items;
- Evaluation of uneconomic adjustment parameters of the Real-Time Market, including discussion of Real-Time dispatch and Real-Time pre-dispatch in the Hour-Ahead Scheduling Process ("HASP");
- Use of the price cap, including a summary of the application of the price cap for the April 1-June 30 time period; and
- In-depth price cap analysis, including discussion of the effect of using lossless shift factors, localized congestion involving the movement of multiple resources, and system energy needs affected by inter-temporal ramping.

In the September 2006 Order, the Commission directed the ISO to "submit quarterly reports evaluating MRTU performance and operational issues for the first year [after implementation of the ISO's new market] and providing information on corrective actions."[5] The ISO developed the evaluative criteria itemized above in consultation with stakeholders as directed by the September 2006 Order.[6] The Commission also directed the ISO to "commence filing post-implementation performance reports on a quarterly basis within 30 days of the end of each calendar quarter."[7] The market services quarterly report is submitted in compliance with these directives.

The September 2006 Order also directed the ISO to include in its quarterly reports "(1) a demonstration of compliance with NERC reliability standards and (2) an assessment of the system's ability to meet the ancillary service control, capability and availability standards set forth in [CAISO] Tariff sections 8.4.2, 8.4.3, and 8.4.4."[8] The market services quarterly report includes a section specifically addressing the ISO's compliance with NERC Reliability Standards. In addition, the section of the market services quarterly report providing an assessment of Ancillary Service control addresses the system's ability to meet the Ancillary Service control, capability, and availability standards set forth in Sections 8.4.2, 8.4.3, and 8.4.4 of the CAISO Tariff, and includes discussion of five specific matters relating to these tariff standards that the September 2006 Order required the ISO to address in its quarterly reports.[9]

The Commission, in its July 17, 2008, order in Docket No. ER06-615-013, approved ISO tariff changes regarding interim scheduling reports provided by the ISO and directed the ISO to "include aggregate information from such interim scheduling reports in the previously-directed [quarterly] reports on MRTU performance."[10] The section of the market services quarterly report regarding aggregate data on interim scheduling charges provides this information.

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[5] *Id.*

[6] *See id.*

[7] *Id.*

[8] *Id.*

[9] "In order to ensure compliance with these standards, we direct the CAISO to include an assessment of the following in its quarterly, post-implementation performance reports: (1) the generating units of each participating generator scheduled to provide spinning reserve and non-spinning reserve are available for dispatch throughout the settlement period for which they have been scheduled; (2) the generating units of each participating generator scheduled to provide spinning reserve are responsive to frequency deviations throughout the settlement period for which they have been scheduled; (3) the ability of ancillary services providers to respond to signals from the CAISO Energy Management System to provide regulation when ACE [Area Control Area] exceeds the allowable CAISO Control Area dead band for ACE; (4) each provider of spinning or non-spinning reserve can provide its resource at the dispatched operating level within ten minutes after issuance of dispatch instructions; and (5) the generating units providing voltage support have automatic voltage regulators to correct the bus voltages within the prescribed voltage limits and within the machine capability in less than one minute." *Id.* at P 1417 n.591.

[10] *California Independent System Operator Corp.*, 124 FERC ¶ 61,043, at P 37 (2008).

In its January 30, 2009, order in Docket No. ER09-213-000, the Commission directed the ISO to discuss in its quarterly reports the status of its efforts to resolve the four "deferred functionalities" addressed in that proceeding: (1) enforcement of Forbidden Operating Region constraints for Generating Units in the Real-Time Market; (2) unlimited Operational Ramp Rate changes for Generating Units; (3) procurement of incremental Ancillary Services in the HASP; and (4) automation of the commitment process for Extremely Long-Start resources. The Commission directed the ISO to provide in its quarterly reports "a timeframe in which each of the deferred functionalities can be restored and implemented."[11] The section of the market services quarterly report regarding the deferred functionality items addresses these matters.

In its January 30, 2009, order in Docket No. ER09-241-000, the Commission noted with approval the ISO's statement that it "will address the functioning of [its] price cap in its quarterly MRTU performance reports.[12] In compliance with this statement, the market services quarterly report includes sections addressing price cap use and in-depth price cap analysis. These sections also provide information consistent with the ISO's statement in the price cap proceeding that it planned to "reserve detailed analysis of the performance of its markets for its quarterly reports where it will provide an analysis of the market conditions causing prices to rise above the cap or fall below the floor."[13]

The Commission, in its February 19, 2009, order in Docket No. ER09-240-000, found the ISO's proposed rules and software parameters under which the ISO will relax transmission constraints, procure ancillary services, or adjust the schedules of priority self-scheduling entities when economically or operationally sensible to be just and reasonable and noted with approval the ISO's commitment to "continually evaluate the parameters in the future, both before and after the MRTU 'go-live' date."[14] The section of the market services quarterly report providing an evaluation of uneconomic adjustment parameters of the Real-Time Market includes an updated ISO evaluation of the software parameters.

Section 40.4.6.2.2.2 of the CAISO Tariff requires the ISO to provide quarterly reports to the Commission on bilateral transfers of Existing Contract import capability. In compliance with this provision, information regarding bilateral transfers of Existing Contract import capability is provided in the market services quarterly report.

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[11] *California Independent System Operator Corp.*, 126 FERC ¶ 61,081, at PP 4, 30, 41, 58 (2009).

[12] *California Independent System Operator Corp.*, 126 FERC ¶ 61,082, at P 39 (2009).

[13] ISO Compliance Filing, Docket No. ER09-241-000 (Mar. 2, 2009), Transmittal Letter at 5 n.6.

[14] *California Independent System Operator Corp.*, 126 FERC ¶ 61,147, at P 82 (2009).

Further, in the transmittal letter for its August 3, 2007, compliance filing in Docket Nos. ER06-615-011 and ER07-1257-000 (at page 39), the ISO stated that, "[d]uring the first year of MRTU, when the CAISO is submitting quarterly post-MRTU implementation reports in accordance with Paragraph 1417 of the September [2006] Order, the CAISO commits to include all [Business Practice Manual proposed revision requests] reports to the CAISO Board in those quarterly reports." Consistent with this commitment, the market services quarterly report includes a discussion of the current status of proposed revisions to the Business Practice Manuals as reported to the CAISO Board.

II. Overview of the DMM Quarterly Report

The DMM quarterly report addresses the following specific matters, which are in addition to the matters discussed in the market services quarterly report:

- In its April 20, 2007, order in Docket Nos. ER06-615-001, *et al.*, the Commission directed the DMM to "monitor and report on the effects of market power mitigation in the day ahead using the CAISO's load forecasts instead of bid-in demand, including a comparison with an estimate of what the amount of mitigation would have been with bid-in demand, in the CAISO quarterly status reports in [Docket No.] ER06-615."[15] Section 2 of the DMM quarterly report contains an analysis that complies with these directives.

- In its June 25, 2007, order in Docket Nos. ER06-615-003 and ER06-615-005, the Commission directed the ISO to monitor frequently mitigated units, analyze "the effects of local capacity area [Resource Adequacy] resource requirements once phased into MRTU to assess whether units needed for local reliability are receiving adequate compensation from [Resource Adequacy] requirements," and "report its findings to the Commission in its quarterly reports."[16] Section 3 of the DMM quarterly report addresses these directives.

Further, in the September 2006 Order, the Commission directed the ISO to "use the three-pivotal-supplier test to identify those transmission paths that are non-competitive during the first year of MRTU implementation," and directed the ISO's Market Surveillance Committee ("MSC"), during that first year, to "examine whether an alternative competitive screen to identify market power opportunities for generation in load pockets should be considered" and report on its findings.[17] The MSC is still collecting information on non-competitive transmission paths and possible alternative approaches, and will submit a report on its findings after it

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15 *California Independent System Operator Corp.*, 119 FERC ¶ 61,076, at P 496 (2007).
16 *California Independent System Operator Corp.*, 119 FERC ¶ 61,313, at P 352 (2007).
17 September 2006 Order at P 1032.

has made the examination directed by the Commission. The ISO anticipates that the MSC will submit that report on January 30, 2010.

III. Contents of Filing and Service

In addition to this transmittal letter, the instant filing includes Attachment A, the market services quarterly report, and Attachment B, the DMM quarterly report. The ISO has served this filing on all parties on the official service lists for the above-referenced proceedings and has posted the filing on its website.

For the above-stated reasons, the attached ISO quarterly reports comply with the Commission's directives and the ISO's own commitments. Please contact the undersigned with any questions.

Respectfully submitted,

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Attachment A
Market Services Quarterly Report

California Independent
System Operator Corporation

California ISO

Post Implementation Report

July 30 2009

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Introduction

This FERC report is filed quarterly thirty days after the end of each quarter and is collated and organized by Market Services, which is part of the Operations division. Contemporaneously with this report the Department of Market Monitoring will be submitting a report which will speak to their specific responsibilities. The original reporting direction which gave rise to this report is FERC Order Paragraph 1417 of the September 21st 2006 order where FERC directed that the ISO will "as of the effective date of MRTU Release 1, commence filing post-implementation performance reports on a quarterly basis within 30 days of the end of each calendar quarter." In addition to this initial instruction FERC also gave a number of subsequent reporting directives. All of these directives are referenced via footnotes at the start of each section so that it is clear why each section is included in this report.

MRTU Performance[1]

Market Characteristics

Loads

For the reporting period April 1st, through June 30th, daily troughs were below the level of the previous year due to the weakness in the economy.

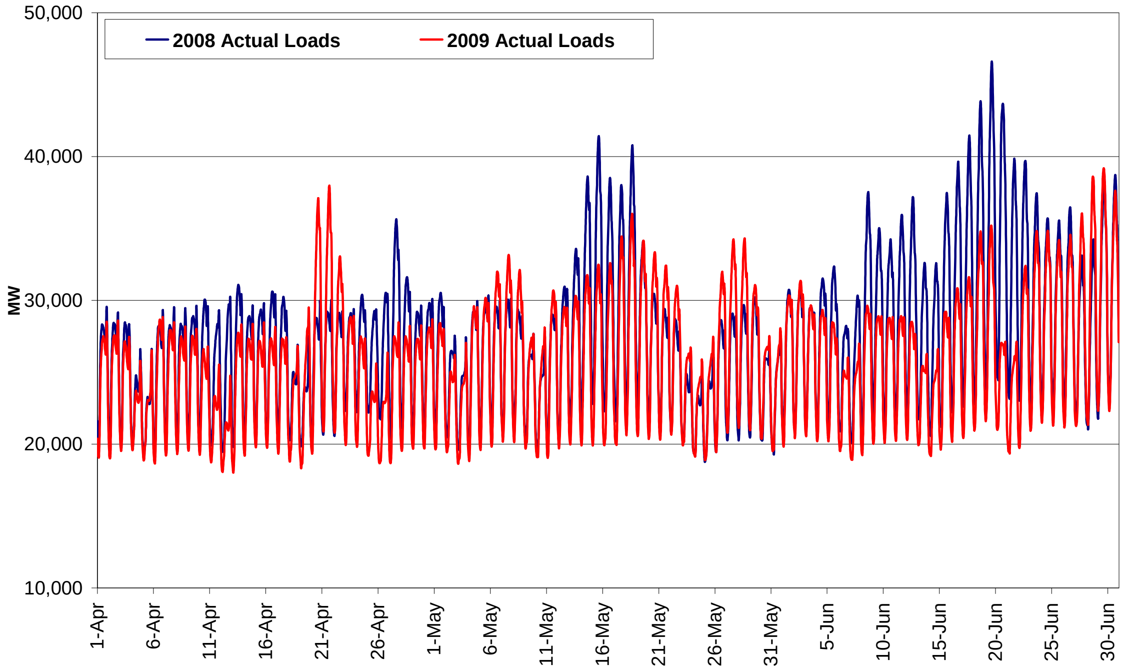
[1] This section of the report is based on instructions in paragraph 1417 of the September 21, 2006 FERC Order, in which the ISO was directed to file reports and provide an opportunity for market participants to contribute to the nature of the reports. To assist in this process the ISO held a series of stakeholder meetings starting in late 2007. During this consultation process the ISO proposed a preliminary set of market metrics to be filed with FERC every quarter. This report would contain numerous metrics which would highlight the performance of various markets operated by the ISO. Prior to the stake holder meeting, the ISO published a template document on its website which contained a set of metrics which the ISO intended to use to monitor the market performance. The stakeholders were generally supportive of this approach and had some suggestions. Whilst the vast majority of these requests have been accommodated there are a few that are still under development. The specifically requested metrics include the following:

1. The uplift payments paid to Scheduling Coordinators (SCs).
2. The Congestion Revenue Rights (CRR) revenue adequacy.
3. The statistics of availability of the ISO market software. Also, the effect of market application failure on market outcomes.
4. Accuracy of the ISO Day-Ahead and Real-Time load forecast compared to the Actual load.
5. The Locational Marginal Prices (LMPs) and aggregated prices of Metered Subsystems (MSS).
6. The exceptional dispatch of Resource Adequacy (RA) units in Day-Ahead and Real-Time Markets.
7. The RUC procurement target and RUC procured quantities.
8. The Ancillary Service requirements and costs.

In the FERC Quarterly Implementation Report for the second quarter of 2009, the ISO has included metrics in item numbers 2, 6, 7 and 8 shown above. On the 15th of every month the ISO files reports with FERC which address the Exceptional Dispatch and Market Disruptions (for example see: http://www.caiso.com/23ec/23ecc26d4b330.pdf). The Exceptional Dispatch and Market Disruptions report include the metrics mentioned in item numbers 3 and 6 shown above. The ISO will continue to develop metrics which will include all the remaining items mentioned above (1,4,&5) and incorporate those in the future FERC quarterly implementation reports. Further, in the light of experience the CAISO has reduced the number of metrics shown in this report to those metrics that paint a broad picture of the market's performance. For further information on market performance please see the monthly reports and the associated metric catalogues, which are publicly posted at: http://www.caiso.com/205c/205cb4c74bc40.html.

With the exception of three days between the April 20th, and April 22nd, when loads spiked due to an atypical heat wave, peak loads in April remained well below 30,000 MW. May had relatively mild load patterns and moderate weather. In June loads trended upwards due to the advent of warmer weather.

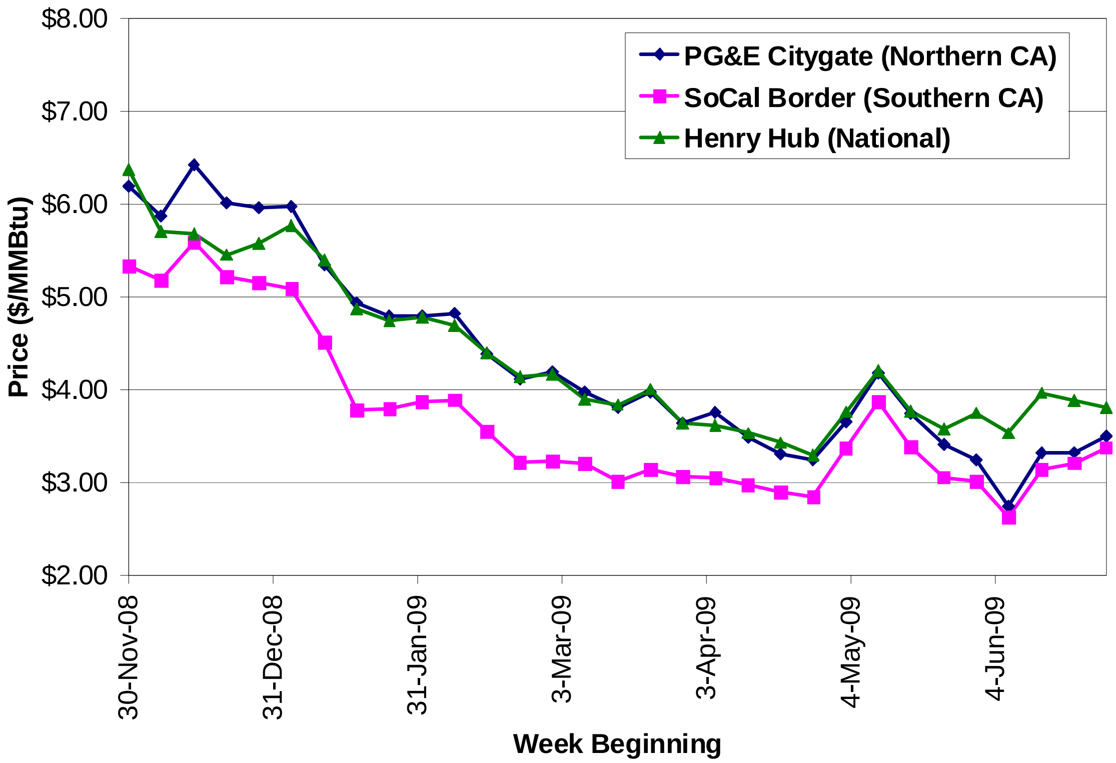
Figure 1: System Load Comparison –2009 v. 2008



Natural Gas Prices and Inventories

Natural gas prices fluctuated between $2.5 /MMBTU and $4.25 /MMBTU from April 1st, through June 30th. Prices declined in April mainly due to moderate weather, economic recession, and robust supply. The increase in crude oil prices, warm temperatures, and a weak US dollar prompted a brief increase in natural gas prices during the first half of May, but prices fall again during the second half due to continuing weakness of economy and moderate temperatures. Gas prices rose steadily in June mainly due to the increase in oil prices and the advent of warmer weather. The California Composite Average gas price inched up 6 cents to $3.35 per MMBtu on June 30th from $3.29 per MMBtu on April 1st.

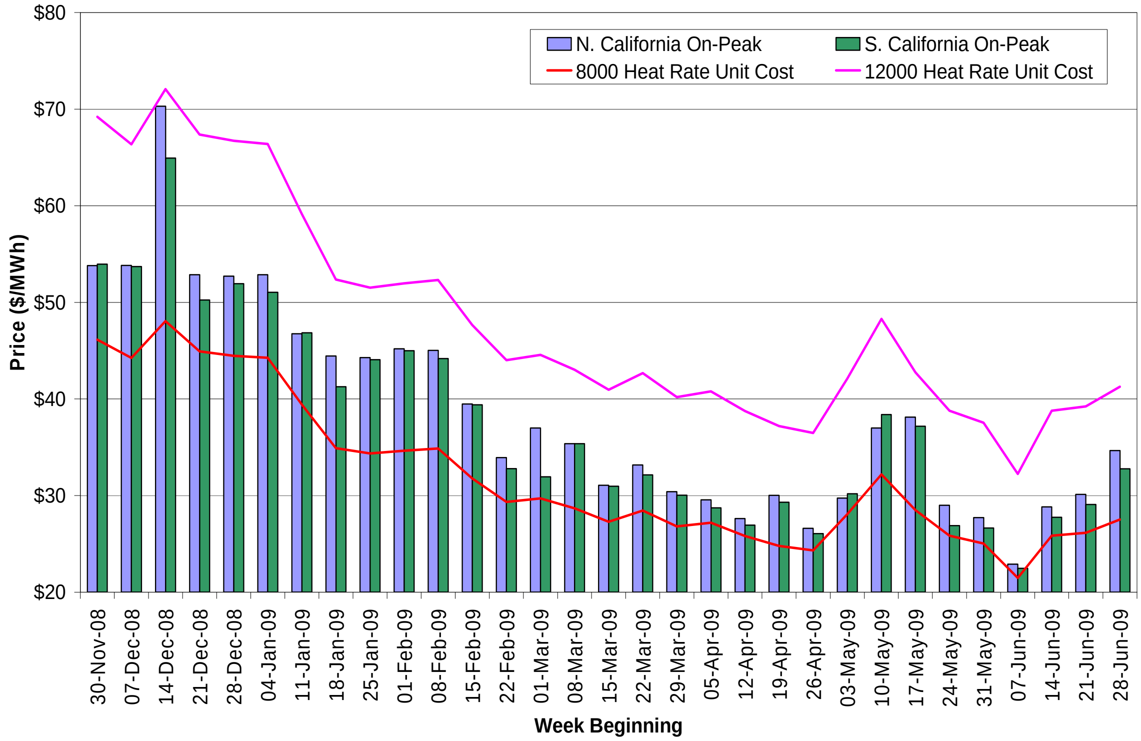
Figure 2: Weekly Average Natural Gas Spot Prices November 2008 to June 2009



Bilateral Electricity Prices

Day-ahead, on-peak power prices declined in April and the second half of May and climbed in the first half of May and June, following the trend in natural gas prices. The increase in electricity prices was driven by high temperatures across the West and rising natural gas prices. Figure 3 compares weekly average on-peak prices for Northern and Southern California with the nominal gas costs for two reference gas turbine generators.

Figure 3: Daily Peak-Hour Bilateral Contract Prices – Weekly Averages



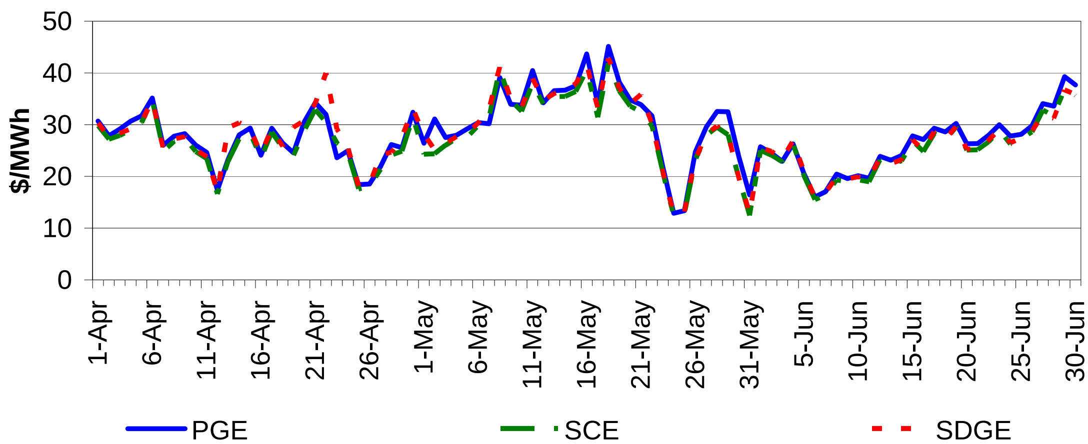
Market Performance Metrics

Day-Ahead Energy Markets

Prices

Figure 4 shows the daily weighted average Load Aggregation Point (LAP) prices for all trading hours during the reporting period. The day-ahead daily average prices were fairly stable, falling into the range of \$12 to \$46. The increasing trend of the prices in the first three weeks of May can be attributed to warm weather and rising natural gas prices. Slack electricity demand for Memorial Day, temperate weather, and slipping gas prices contributed to the slump of average prices from May 23rd to May 25th. The average LAP prices increased steadily in June except in the first few days of June, thanks largely to the warmer temperature and rising natural gas prices.

Figure 4: Day-Ahead Weighted Average LAP Prices (All Hours)



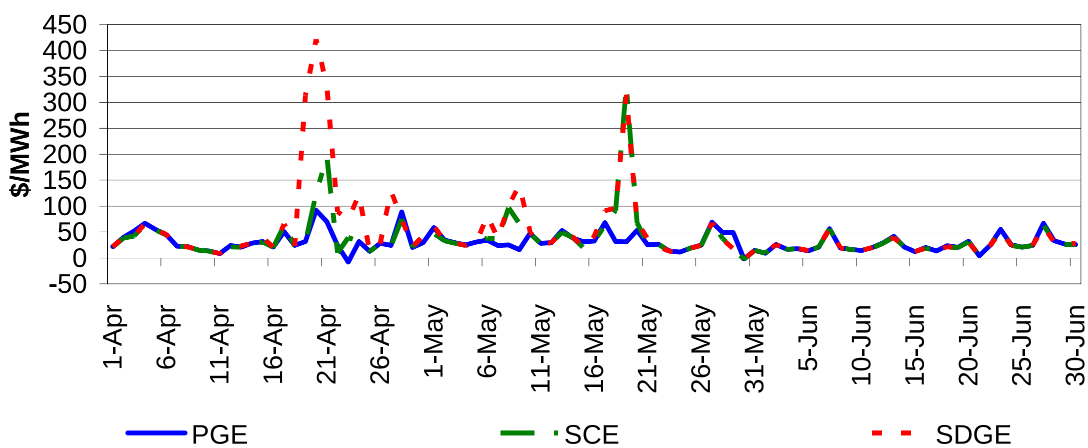
Real-Time Energy Markets

Prices

The daily real-time energy prices are shown in Figure 5 for three LAPs for the second quarter of 2009. Prices were generally stable for the quarter with a few exceptions in April and May, when prices in the SDGE and the SCE areas were elevated by congestion on certain transmission lines on several days. This congestion was mostly driven by de-rates on those lines due to scheduled outages. Prices were much less variable in June than in May and April, especially in the SCE and SDGE areas. Two main factors contributed to the relatively low prices in June: moderate load due to temperate weather and less congestion due to reduced scheduled maintenance work.

Most of the prices of the quarter fell into the range of $0 and $100. There were several days with prices higher than $100 for the SDGE area and the SCE area, 6 days and 3 days respectively. PG&E has the least variable prices among the three LAPs.

Figure 5: Real-Time Weighted Average LAP Prices (All Hours)

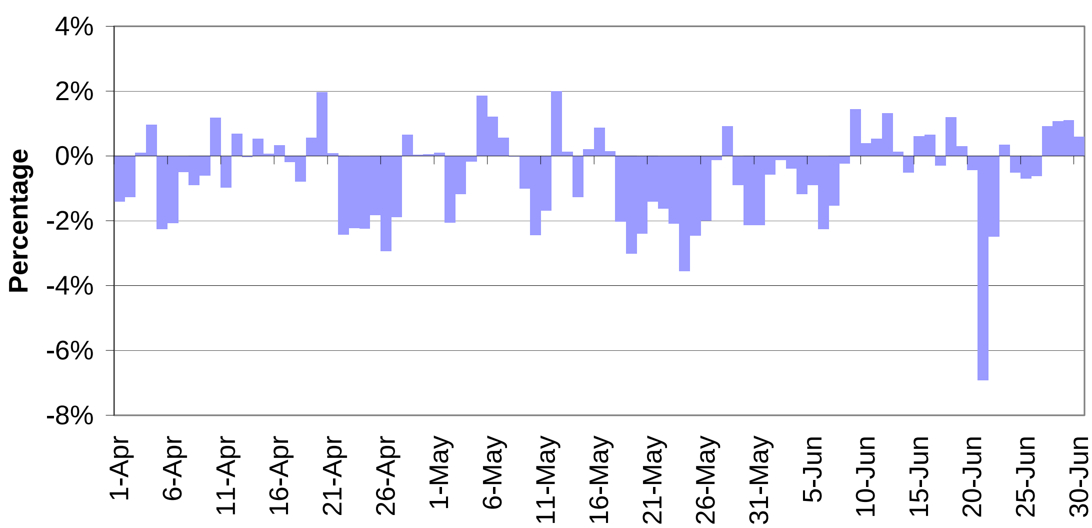


Residual Unit Commitments

The Residual Unit Commitment (RUC) process is a reliability run that occurs after the IFM. The RUC process differs from the IFM primarily in that it runs against the CAISO Forecast of CAISO Demand (CFCD) rather than bid-in demand. The purpose of this section is to show how often the RUC process backstops the IFM and the costs that are incurred as a result. RUC capacity is the positive difference between the RUC schedule and the greater of the IFM schedule and the minimum load level of a resource. The RUC award is the portion of RUC capacity in excess of Reliability Must-Run (RMR) capacity or the Resource Adequacy (RA) RUC obligation. All RUC awards are paid the RUC LMP. RA and RMR units do not receive the additional payment for their RUC capacity because they are already compensated through their RMR or RA contracts.

Figure 6 presents the daily average deviation of the RUC schedule from the IFM schedule for the second quarter of 2009, which is an average across all the trading hours for each trading day. The RUC schedule is the total hourly capacity award which includes the day-ahead schedule. As this is a daily average the positive deviations indicate that RUC capacity was procured on that trading day, however the negative deviations do not necessarily imply the absence of RUC capacity procurement. If the deviation is positive in any trade hour on a particular trading day, then RUC capacity was procured on that day. However, if there are negative deviations in other trade hours, the daily average deviation might be negative for that trading day. A negative deviation only implies that on average there is over-scheduling in the IFM compared with the CAISO Forecast of CAISO Demand (CFCD) on that trading day.

Figure 6: Daily Deviation of RUC Schedule from IFM Schedule



The daily average deviations of the RUC schedule from the IFM schedule were relatively small for the second quarter of 2009, as shown in Figure 6.

Approximately 79 percent of the deviations fell into the range of -2 percent and 2 percent, and the rest were all lower than -2 percent. The deviations peaked at approximately 2 percent on three days, when a relatively large amount of RUC capacity was procured. In contrast, on June 21st, the daily deviation reached the minimum at -6.9 percent, when the IFM schedule was well above the RUC schedule for most hours on that day.

The daily RUC award and the weighted average RUC LMP are represented in Figure 7 for the second quarter of 2009. The weighted RUC LMP is not specified if there was no RUC award on that trading day. For the quarter, the average daily RUC award procurement is 3.02 MWs, and the average price is $4.15. There were RUC awards on approximately two-thirds of the days in the quarter, however only on one third of the total days were the procured RUC awards greater than 5 MWs. The daily RUC award peaked at 27 MWs on April 20th due to a large increase in load during a heat wave. The RUC LMP peaked at $21 on May 27th due to congestion on the Victorville-Lugo branch group.

Figure 7: Daily RUC Award and LMP

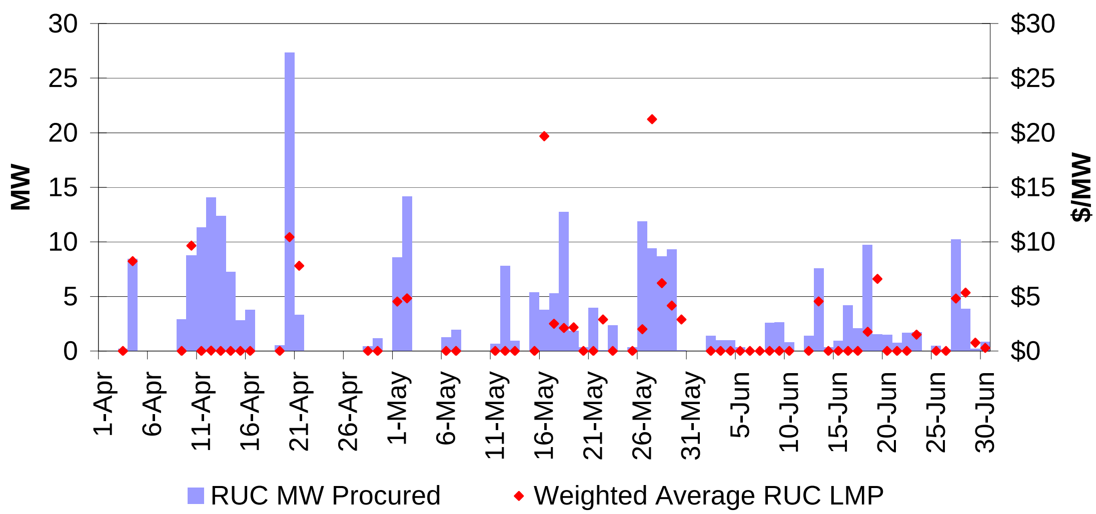
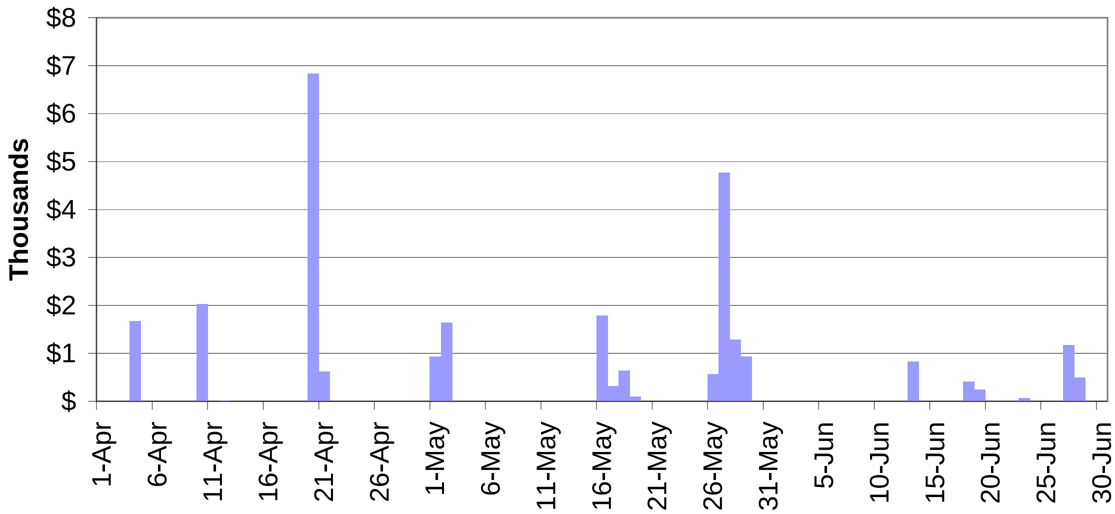


Figure 8 shows the daily cost of RUC procurement for each trading day for the second quarter of 2009. The total RUC procurement costs were $11,181, $12,997 and $3,236 in April, May and June, respectively. The daily RUC cost peaked at $6,843 on April 20th. Overall these graphs show that the RUC process was not relied on particularly heavily and when it was it was not excessively costly.

Figure 8: Total RUC Cost

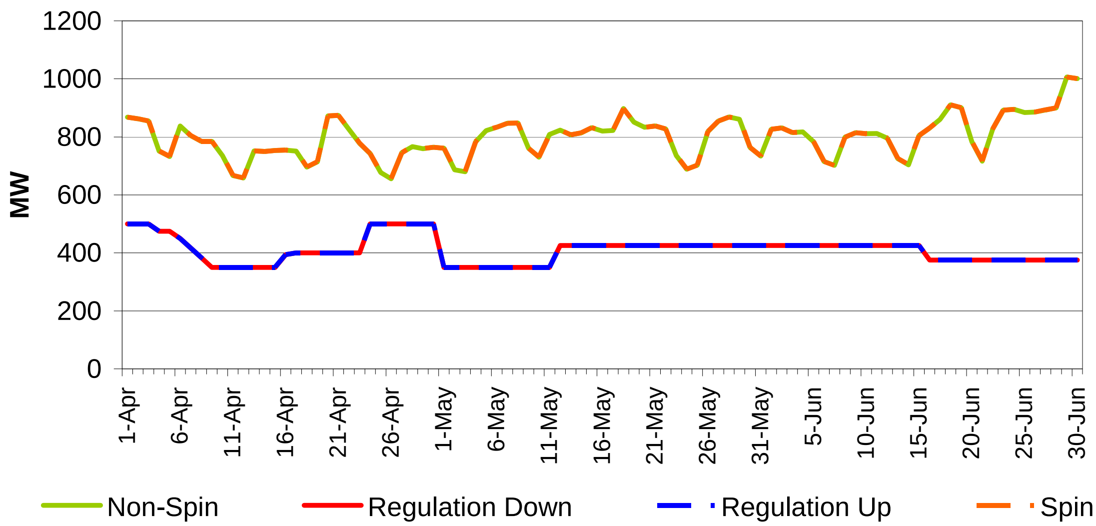


Ancillary Service Markets

Requirements and Prices

Figure 9 below shows the day-ahead average daily Ancillary Service requirements for the second quarter of 2009. Requirements for the start of the nodal market (April 1st, 2009) were increased somewhat compared to what the ISO had traditionally procured. The hourly regulation requirements prior to go-live were 350 MW, but were increased to 500 MW on April 1st. The Operating reserve requirements were also increased to 6.9 percent of the load forecast. By April 10th, the operating reserve requirements were reduced to six percent of load forecast and the regulation requirements were reduced back to 350 MW, the pre-go live level. The Operating reserve requirements were again increased from April 20th, to April 26th, when the ISO system was experiencing a heat wave. The regulation requirements were also increased from April 24th till April 30th to 500 MW. In May and June the hourly regulation reserve requirements hovered between 350 MW and 425 MW and the operating reserve requirement hovered between 6.0 and 6.3 percent of the load forecast.

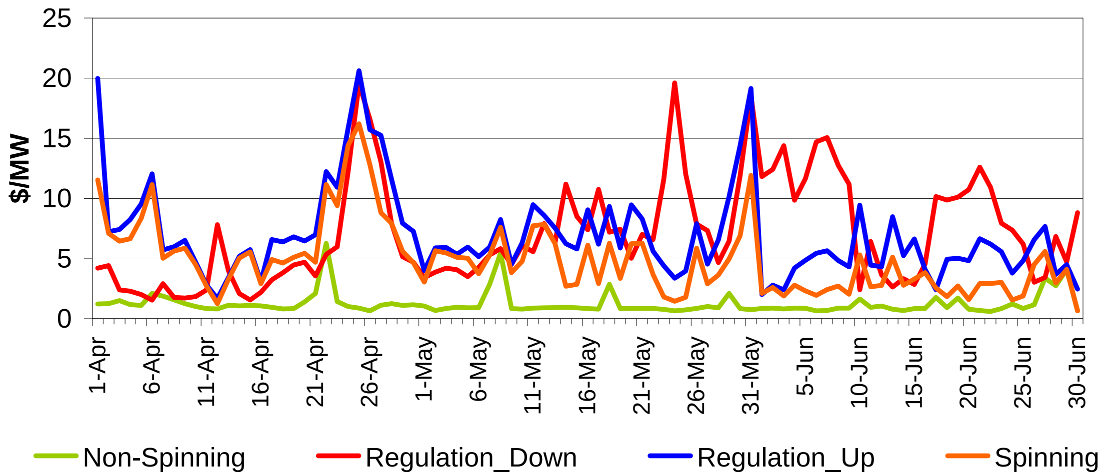
Figure 9: Day-Ahead Ancillary Service Average Requirements



The ISO procures 100 percent of its Ancillary Service requirements in the IFM market based on the day-ahead load forecast. An increase in load forecast in real-time results in incremental procurement, however, if the load forecast reduces in real-time no changes are made to the Ancillary Services procured in the IFM market. Figure 10 below shows the daily IFM (day-ahead) average prices for the second quarter of 2009. The daily average price for each type of ancillary service is calculated as the average of the hourly price for all trading hours. The hourly price is equal to the total cost of procuring non-self scheduled ancillary service divided by the total non-self scheduled procurement.

All four types of Ancillary Services saw some price excursions on April 1st, and from April 20th, to April 27th, primarily driven by the increase in requirements during those days. The regulation down price excursions in the second week of May and on numerous days in June were motivated by higher prices in the early morning off-peak hours. During those hours, the system was experiencing light loads and most of the units were dispatched at their minimum operating levels, which were also their economic operating levels. In order to provide regulation down Ancillary Service, some of the units were dispatched above their economic operating point. The opportunity cost to a resource of dispatching it above its economic operating point to provide regulation down is the forgone revenue in the energy market. Therefore, all resources that are awarded regulation down receive a payment equal to or greater than the sum of its regulation down bid price and opportunity cost arising from its dispatch in the energy market. The elevated prices for regulation down were motivated by the opportunity cost in the energy market.

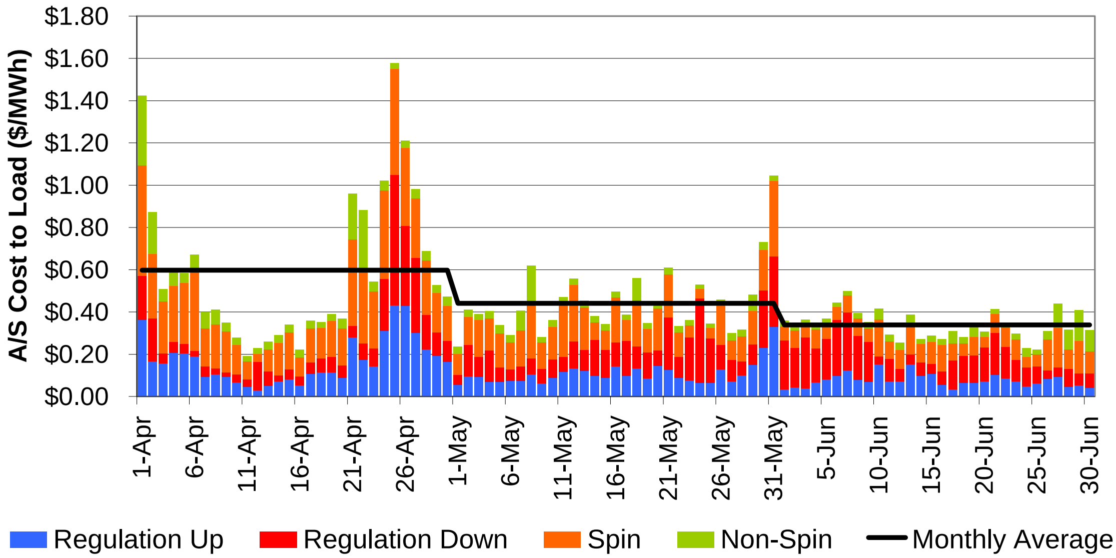
Figure 10: IFM Ancillary Service Average Price



Cost to Load

Figure 11 below shows the total system (day-ahead and real-time) average cost to load for Ancillary Services procurement for the second quarter of 2009. The monthly average cost to load declined steadily during the second quarter from $0.60/MWh in April to $0.34/MWh in June. The steady decline in cost to load is attributed largely to a steady decline in the Ancillary Service requirement.

Figure 11: System (Day-Ahead and Real-Time) Average Cost to Load

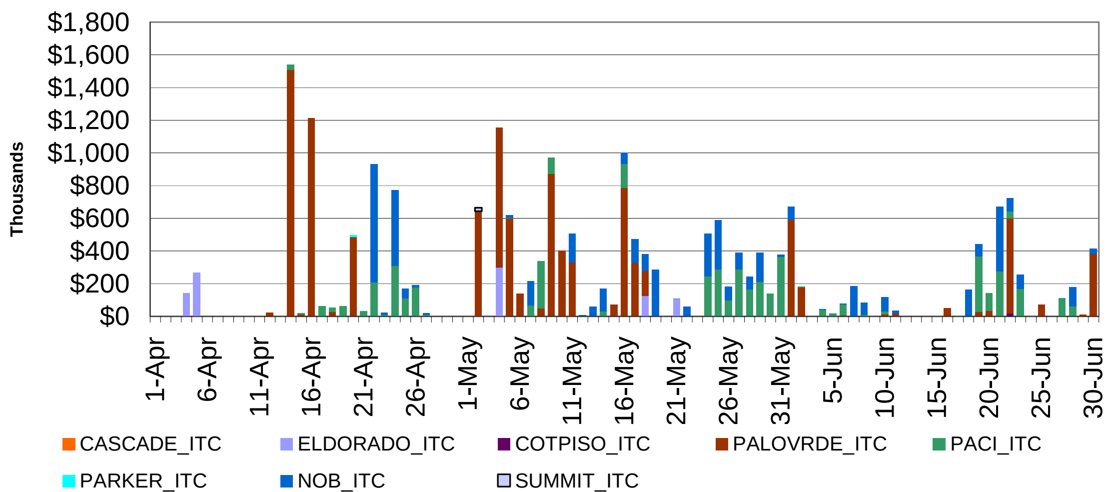


IFM Congestion

Congestion on Interties in IFM

Figure 12 below illustrates the daily total IFM congestion rents by inter-tie for the second quarter of 2009, while Table 1 provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by intertie. The Congestion rent for an intertie is calculated as the shadow price multiplied by the flow limit. The cumulative total congestion rent for the second quarter of 2009 was approximately $21 million. Of the total, the vast majority of rents occurred on three interties: Palo Verde (49 percent), PACI (22 percent) and NOB (23 percent).

Figure 12: IFM Congestion Rents by Intertie (Import)



During spring months, mid March through May, loads are relatively light and it is an opportune period for maintenance. In April and May, numerous transmission and generation owners had scheduled outages which motivated congestion on various interties and branch groups. On some days, congestion was also driven by over-scheduling on interties when scheduling coordinators were importing cheap energy from the neighboring states and the total bid-in schedules exceeded the available capacity.

On April 14th, and April 16th, the Palo Verde intertie was derated sharply by approximately 1500 MW due to scheduled maintenance on Devers- Palo Verde 500 kV line. This contributed to 26 percent of total congestion rents on the Palo Verde intertie. Congestion rents on the PACI and NOB interties in May and June were driven by a combination of over-scheduling and path capacity derates in turn caused by scheduled transmission line maintenance. The availability of cheap hydro power in Pacific Northwest contributed to over-scheduling on the PACI and NOB interties.

Table 1: IFM Congestion Statistics by Inter-Tie (Import)

Inter-Tie	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
BLYTHE_ITC	Apr-2009	0	98	25
COTPISO_ITC	Apr-2009	25	4	7
ELDORADO_ITC	Apr-2009	702	23	25
NOB_ITC	Apr-2009	1591	20	41
PACI_ITC	Apr-2009	2277	5	98
PALOVRDE_ITC	Apr-2009	1948	27	68
PARKER_ITC	Apr-2009	196	56	1
CASCADE_ITC	May-2009	80	16	1
COTPISO_ITC	May-2009	24	54	3
ELDORADO_ITC	May-2009	913	16	36
MARBLE_ITC	May-2009	0	65	24
NOB_ITC	May-2009	1530	10	152
PACI_ITC	May-2009	2444	8	120
PALOVRDE_ITC	May-2009	1695	19	167
SUMMIT_ITC	May-2009	45	457	1
COTPISO_ITC	Jun-2009	24	60	12
NOB_ITC	Jun-2009	1489	9	115
PACI_ITC	Jun-2009	2698	5	88
PALOVRDE_ITC	Jun-2009	2497	11	79

Congestion on Branch Groups in IFM

Figure 13 illustrates IFM daily total congestion rents on branch groups, while Table 2 provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by branch group. The daily total congestion rent is the sum of hourly congestion rents for all trading hours. The hourly congestion rent is calculated as the shadow price multiplied by the flow limit. For the second quarter of 2009, the total branch group congestion rent was approximately $7.54 million. The majority of branch group congestion rents occurred on the SDGE_CFEIMP branch group (45 percent), the Path15 branch group (12 percent), IPPDC branch group (15 percent) and the Los Banos-North branch group (11 percent).

Approximately 50 percent of the total congestion rents on SDGE_CFEIMP branch group occurred on April 30th where the branch group was derated due to scheduled maintenance on the Encina-Penasquitos 230 kV line. On May 1st, the Moss Landing-Los Banos 500 kV line was out for scheduled maintenance and this motivated significant congestion rents on the Los Banos-North branch group. Most of the congestion on Path-15 occurred from May 28th through May 31st, driven by path capacity derates, in turn motivated by scheduled maintenance of the Diablo-Gates 500 kV line.

Figure 13: IFM Congestion Rents by Branch Group

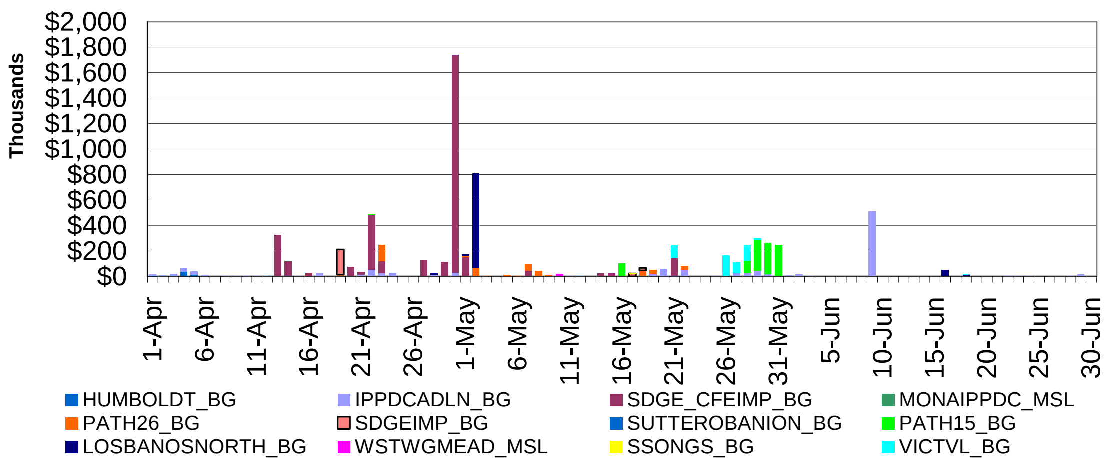


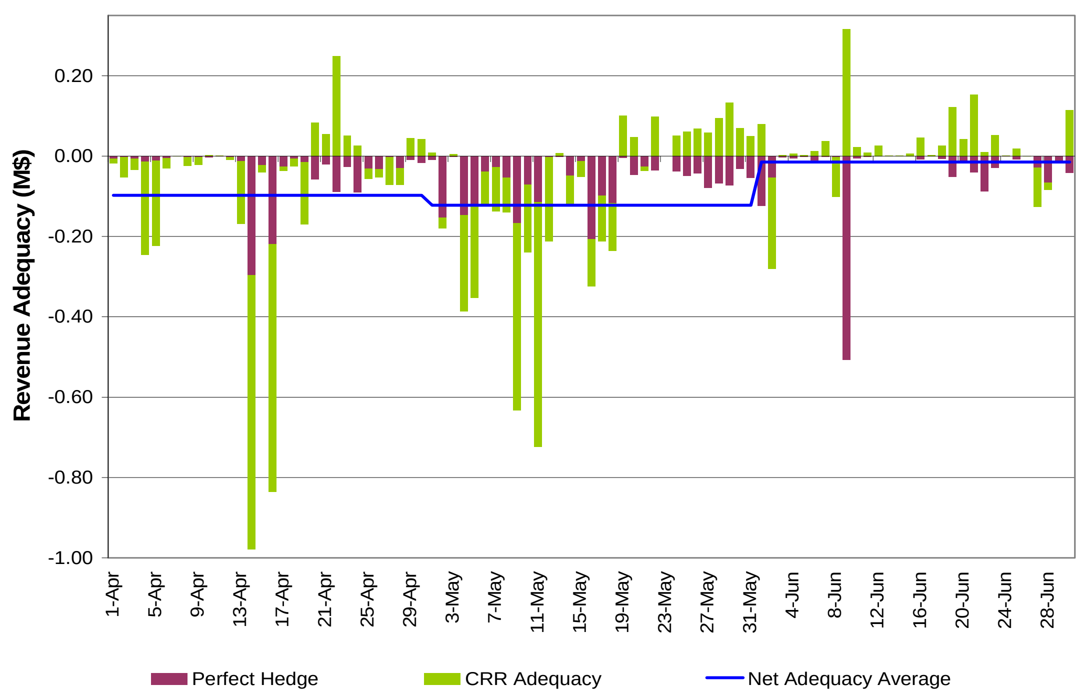
Table 2: IFM Congestion Statistics by Branch Group

Branch Group	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
HUMBOLDT_BG	Apr-09	39	55	34
IPPDCADLN_BG	Apr-09	444	3	203
LOSBANOSNORTH_BG	Apr-09	2168	3	3
MONAIPPDC_MSL	Apr-09	236	4	3
PATH15_BG	Apr-09	2800	1	1
PATH26_BG	Apr-09	2000	5	15
SDGEIMP_BG	Apr-09	1650	13	9
SDGE_CFEIMP_BG	Apr-09	2461	19	66
SUTTEROBANION_BG	Apr-09	525	0	1
HUMBOLDT_BG	May-09	43	23	1
IPPDCADLN_BG	May-09	644	4	100
LOSBANOSNORTH_BG	May-09	2218	31	11
MONAIPPDC_MSL	May-09	236	11	1
PATH15_BG	May-09	2528	9	43
PATH26_BG	May-09	1391	6	39
SDGEIMP_BG	May-09	1231	3	11
SDGE_CFEIMP_BG	May-09	2164	5	34
SSONGS_BG	May-09	1520	0	3
SUTTEROBANION_BG	May-09	525	2	1
VICTVL_BG	May-09	2400	6	36
WSTWGMEAD_MSL	May-09	116	15	10
HUMBOLDT_BG	Jun-09	43	14	10
IPPDCADLN_BG	Jun-09	549	27	49
LOSBANOSNORTH_BG	Jun-09	1964	3	9
SDGEIMP_BG	Jun-09	2550	0	1
VICTVL_BG	Jun-09	2400	1	1
WSTWGMEAD_MSL	Jun-09	186	1	1

Congestion Revenue Rights[2]

Figure 14 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the second quarter of 2009. Net positive values indicate that there is a surplus and net negative values indicate there is a shortfall. Revenue adequacy for CRRs reflects the extent to which the hourly net congestion revenues collected from the Integrated Forward Market (IFM) are sufficient to cover the hourly net payments to CRR holders. Another factor affecting CRR revenue adequacy is the congestion credits for holders of existing rights (TOR, ETC and CVR) who are exempt from IFM congestion charges in accordance with the perfect hedge provisions of the ISO tariff. The perfect hedge reduces the net IFM congestion revenues available for paying CRR holders, and therefore the ISO accounts for the expected impact of the perfect hedge on CRR revenue adequacy in the process for releasing CRRs and in quantifying revenue adequacy.

Figure 14: Daily Revenue Adequacy of Congestion Revenue Rights



The hourly CRR revenue adequacy amounts (net congestion revenues minus net payments to CRR holders, as reflected in the green bars in Figure 14) and the congestion credit for the perfect hedge are aggregated across all hours of each month to obtain the net revenue adequacy and supplemented by the net CRR

[2] The metrics presented in this section and also in the sections of Post-DA Perfect Hedge and Cost of the Perfect Hedge are based on preliminary Settlements data. For the months of April and May, the metrics are based on T+38B data, while for the month of June the metrics are based on T+7B.

auction revenues collected by the ISO for the month through the mechanism of the CRR Balancing Account. Auction revenues are not incorporated in Figure 14. The net surplus or deficit in the CRR Balancing Account at the end of each month is then allocated to all measured demand exclusive of demand associated with accepted self-schedules utilizing existing rights (ETC, CVR, TOR) in accordance with the ISO tariff. Thus, in accordance with the principle of full funding of CRRs, any deficit in the CRR Balancing Account at the end of a month does not adversely affect the payments to CRR holders. In Figure 14, the cost of the perfect hedge is independently depicted to better visualize its extent, even though it is also a component of the net revenue adequacy. The blue line in Figure 14 shows the monthly average of the daily net revenue adequacy, which includes the impact of both the CRRs payments and the cost of the perfect hedge on revenue deficiency.

Revenue deficiencies have been observed during the first three months of the new ISO markets. The ISO has adjusted its monthly CRR release processes aiming to attain revenue adequacy on a monthly basis using only the IFM congestion revenues including the effects of the perfect hedge minus net payments to CRRs, without relying on the CRR auction revenues. At the same time, the ISO is trying to ensure revenue adequacy without adversely affecting the quantity of CRRs released. There are two adjustments the ISO uses for this purpose:

a) Modeling of outages in the monthly CRR release processes. Because transmission outages play an important role in revenue adequacy, a critical element of the ISO's monthly CRR release process is to account for the impact of expected transmission outages in the monthly CRR releases. However, with no historical data from actual operation under the new market paradigm, the ISO was not able to estimate the likely impact of outages. The ISO tariff requires that Participating Transmission Owners submit requests to the ISO to schedule significant outages at least 30 days prior to the start of the month in which the outage will occur. This 30-day rule provides a critical mechanism for the ISO to account for significant transmission outages when determining the network capacity available for each monthly CRR release process. However, this rule has only been in effect since March 31, 2009, and therefore the ISO did not have any 30-day rule information to model planned outages for releasing monthly CRRs for April. Starting with the release of May CRRs, the ISO was able to utilize information provided by the 30 day-rule to improve the modeling of outages. For May, only the transmission elements with outages with a duration of 10 days or longer were removed from the network model used in the monthly CRR release process. With actual operational data becoming available, however, the ISO subsequently identified the need to also model outages of transmission facilities with durations of less than 10 days. As Figure 14 illustrates, major impacts on monthly revenue adequacy were concentrated on a few days each month when short duration outages on major interfaces were driving significant revenue deficiencies. Effectively for the June-and-onwards monthly processes, outages with duration of less than 10 days have also been modeled with pro-rata derates to reflect the portion of the month they were planned to be out of service.

b) Global Derating Factor. Outages that cannot be captured by the 30-day rule, such as unscheduled outages, cannot be explicitly reflected in the CRR release process. To account for the likelihood of unscheduled outages, the monthly CRR process employs a global derating factor which reduces the system-wide transmission capacity available in the release process and thereby limits the number of CRRs released. For the month of April and in lieu of the 30-day rule, a global derating factor of 2.5 percent was used; it turned out, however, that this was a grossly insufficient percentage to account for the impact of all the outages. For the month of May, the global derating factor was increased to 10 percent, but only for Tier 2 of the allocation and the auction. Tier 1 of the allocation was still processed with a derating factor of 2.5 percent because the ISO did not yet have sufficient market results to indicate the need for larger derating at the time the Tier 1 process was conducted. Again it turned out that the global derating factors for May were still insufficient preserve revenue adequacy. The global derating factor used for June through August is 15 percent. For June, this derating factor was still insufficient to ensure revenue neutrality, though the revenue deficiency for June was much less than for April and May.

The main factor that drove revenue deficiency in this second quarter was the significant volume of outages, for which the modeling of the 30-day rule outages and the global derates discussed above were not sufficient to ensure revenue adequacy. Due to light loads, late spring is typically chosen as a time for routine maintenance on transmission lines, and April and May 2009 were no exception. All major revenue deficiencies observed in this quarter were driven by outages and derates on several major transmission facilities, with derates on Palo Verde being the most significant contributor throughout the quarter even though its derates were of short duration. For instance, the outages that required derates on the Palo Verde inter-tie on April 14th and 16th accounted for approximately 60 percent of the total revenue deficiency of the entire month. Revenue surpluses, in contrast, have been more frequent since the end of May, when the number of outages started declining. As shown in Figure 14, the daily average of revenue deficiency has been $97,655, $122,334 and $14,970 for April, May and June, respectively.

Table 3 provides a summary of the monthly statistics for CRRs for the second quarter. The Net Adequacy accounts for both the CRR adequacy and the cost of the perfect hedge. The Revenue Adequacy Ratio is the ratio of the money collected from the IFM to the money paid to both the CRR entitlements and the Perfect Hedge. The auction revenues reflect both the monthly shares of the annual auction and the individual monthly auction processes. Once the auction revenues are used to offset the revenue deficiencies in the monthly clearing process, the net amount to be allocated to measured demand was negative only for the month of May. Although auction revenues can be used to offset any CRR revenue deficiency that results from the IFM, the intention of the ISO's CRR release process is that proceeds from the IFM should be sufficient to cover both the CRR payments and the cost of the perfect hedge over the course of each month, so that the auction revenues can be returned to measured demand as fully as possible. The annual and monthly processes to release CRRs through allocations and auctions are designed and conducted based upon this concept.

Table 3: Summary of Monthly Revenue Adequacy

	April	May	June
Congestion Rents	$9,615,368.01	$14,836,219.36	$6,442,759.92
CRR Payments	$11,484,090.75	$16,689,162.38	$5,772,604.08
CRR Adequacy	-$1,868,722.74	-$1,852,943.02	$670,155.84
Perfect Hedge	-$1,060,950.28	-$1,939,427.46	-$1,119,271.10
Net Adequacy	-$2,929,673.0	-$3,792,370.5	-$449,115.3
Adequacy Ratio	76.6%	79.6%	93.5%
Auction Revenues	$3,315,470.4	$3,485,874.2	$3,570,311.5
Monthly Net Balance	$385,797.3	-$306,496.3	$3,121,196.2

For each month, auctions revenues were used to offset the revenue deficiencies, with still some surplus left in the balancing account for April and June (Monthly Net Balance) to be distributed to measured demand. In May, in contrast, there is a net revenue deficiency that will be allocated to measured demand. Through the quarter, the revenue adequacy ratio has improved from 76.6 percent to 93.5 percent, as deficiencies have decreased from $2.92 million to $0.45 million while auction revenues have been above the $3 million mark.

Post-DA Perfect Hedge

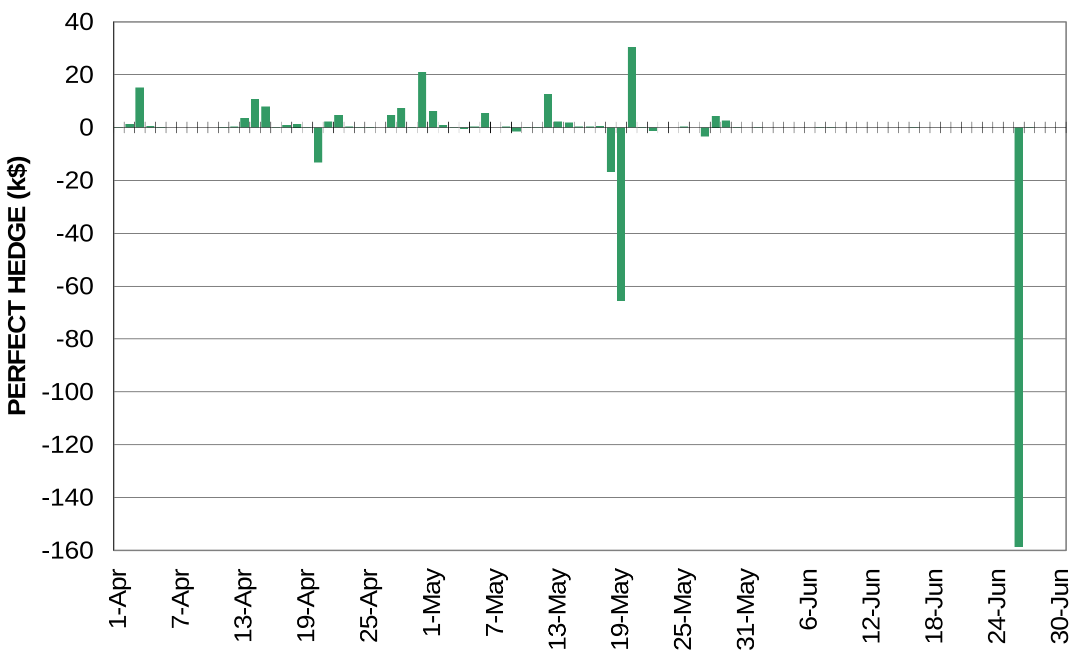
Similar to the day-ahead (DA) market, the ISO collects RTM congestion rents determined by the charges to demand and payments to supply for schedule deviations from DA schedules and imports of Ancillary Services via the interties. Depending on contract provisions, some holders of ETCs/TOR may utilize their rights to submit post-DA, i.e. in the HASP/RT frame, schedule changes with respect to their accepted DA self-schedules.[3] As required by the ISO Tariff,

[3] Converted Rights (CVR) are only eligible for the perfect hedge in association with accepted self-schedules in the IFM.

these schedules are exempt from congestion charges and, thus, congestion charges are reversed through the mechanism of the perfect hedge. This is in addition to and independent of any settlement of the DA market. The remaining RTM congestion rents –surplus or deficit– are allocated to measured demand excluding measured demand associated with valid and balanced portions of ETC/TOR. Because the congestion rents and the perfect hedge costs for the RTM do not figure in any way into the settlements of CRRs, the ISO accounts for these in real time funds through a separate real-time mechanism instead of the CRR balancing account.

Figure 15 shows the daily net cost for honoring the perfect hedge of post DA schedule changes of ETC/TOR. A negative value of the perfect hedge indicates a net payment from the ISO to the ETC/TOR holders to reverse the post day-ahead congestion charge, i.e., a credit. A positive value of the perfect hedge indicates a net charge to the ETC/TOR holders to reverse the post day-ahead congestion payment.

Figure 15: Cost of the Perfect Hedge for Post-DA ETCs/TORs

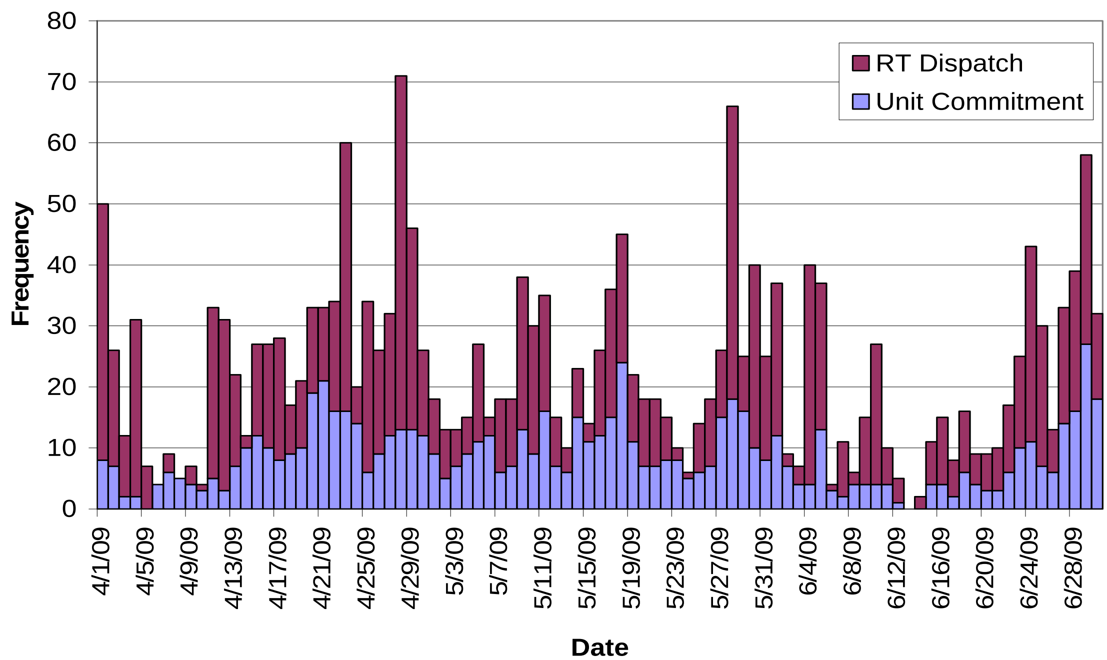


The extent of the cost of the perfect hedge for post-DA schedule changes for ETC/TORs depends not only on the post-DA congestion but also on the extent of schedule changes submitted by their holders. As shown in Figure 15, the cost of the perfect hedge for post-DA transactions has been relatively low. The most significant cost was incurred on June 26. In terms of the total post-DA congestion rents on that day, however, the cost of the perfect hedge on this day is only approximately 17 percent.

Exceptional Dispatch

For the reporting period April 1 though June 30, Figure 16 identifies 2,078 instances of Exceptional Dispatches broken out by type of dispatch – either unit commitment to minimum load or real-time market dispatch. Approximately 80 percent of the Exceptional Dispatches were for generators and the remaining 20 percent were intertie dispatches. Despite a late-June rise in the use of Exceptional Dispatch following a climb in average system loads, on monthly average basis, there is a clear declining trend in the use of Exceptional Dispatch over the three month period. The average daily utilization rate in April was 26 per day, followed by 23 per day in May and 20 per day in June.[4]

Figure 16: Summary of Exceptional Dispatch Frequency (Unit Commitment vs. RT Dispatch)



[4] For a more detailed analysis of Exceptional Dispatch, see the FERC Informational Filing in Docket Nos. ER06-615-000, ER07-1257-000, ER08-1178-000, and EL08-88-000 (Amendment to Tariff re: Exceptional Dispatch) at http://www.caiso.com/232a/232a75413f690.html .

Cost of the Perfect Hedge[5]

This section reflects and summarizes information already presented earlier in this report. It is re-presented here specifically to address the filing directive footnoted on this page. Table 4 lists the monthly summary of both the DA and the post-DA (HASP/RT) congestion rents and perfect hedge costs. Any congestion surplus or deficit is allocated to measured Demand excluding the valid and balanced portion of the corresponding TOR/ETC/CVR Self-Schedules. The percentage shown is the ratio of the perfect hedge to the congestion rents. This provides a reference of the extent of the cost charged to demand not holding ETC/TOR/CVR to honor the perfect hedge in comparison to the overall congestion cost of the DA and post-DA markets.

Table 4: Summary of the Cost Associated to the Perfect Hedge

	DA Market			RT Market		
Month	Congestion Rents	Perfect Hedge	Cost Percentage	Congestion Rents	Perfect Hedge	Cost Percentage
April	$9,615,368.01	-$1,060,950.28	-11.03%	-$9,857,956.01	$68,383.94	-0.69%
May	$14,836,219.36	-$1,939,427.46	-13.07%	-$4,003,950.37	-$20,435.16	0.51%
June	$6,442,759.92	-$1,119,271.10	-17.37%	-$1,174,233.21	-$158,629.84	13.51%
Total	$30,894,347.29	-$4,119,648.85	-13.33%	-$15,036,139.59	-$110,681.06	0.74%

The cost of the perfect hedge to non-ETC/TOR/CVR loads in the DA market during the second quarter was approximately $4.1 million, which represents 13.3 percent of the congestion rents collected in the IFM market. As detailed in the CRR section above, in each month of the quarter, the perfect hedge requirements reduced the available funds from the congestion revenues of the IFM, which in turn contributed to the CRR revenue deficiencies. Because the auction revenues were sufficient to offset all the revenue deficiencies in April and June, the cost of the perfect hedge was entirely reflected as a reduction of the surplus to be distributed to non-ETC/TOR/CVR measured demand.

Compared to the Day-Ahead market costs, the cost of the perfect hedge in the real-time market was much smaller, only $110,681.06 for the entire quarter due to low volumes of schedule changes for ETC/TORs. The post day-ahead cost of the perfect hedge amounts to just 0.74 percent of the total congestion cost of this quarter. Because the congestion revenues in RTM were a negative balance (deficit) allocated to non-ETC/TOR measured demand and the perfect hedge in April were a collection of money from right holders, the perfect hedge in April reduced the charges to non-ETC/TOR demand. For May and June, in contrast, the perfect hedge was an additional cost to non-ETC/TOR loads that were allocated the net negative congestion rents.

[5] As required by the Order Accepting Compliance Filing issued on September 22, 2006, in this section the CAISO is providing the costs associated with honoring ETC/TOR/CVR and charged to non-ETC/TOR/CVR loads in the second quarter of 2009.

Reliability – Compliance with NERC Reliability Standards[6]

Paragraph 1417 of the September 2006 MRTU Order requires "a demonstration of compliance with NERC reliability standards." As detailed below, since the issuance of its September 2006 MRTU order, the Commission has approved a comprehensive compliance regime to ensure that public utilities comply with the mandatory reliability requirements. As a consequence, the ISO has an extensively documented program to ensure compliance with NERC Reliability Standards.

Subsequent to the issuance of the September 2006 MRTU Order, the Commission approved the comprehensive compliance regime developed by NERC as the Electric Reliability Organization ("ERO") pursuant to Section 215 of the Federal Power Act ("FPA").[7] This compliance regime ensures that all users, owners, and operators of the bulk power system, including public utilities such as the ISO, comply with the Reliability Standards applicable to them. In March 2007, the Commission issued a final rule, "Order No. 693," in which it conditionally approved a number of mandatory Reliability Standards that NERC had submitted for Commission approval.[8] In April 2007, the Commission approved delegation agreements between NERC and each of the eight regional entities in the United States (and portions of Canada and Mexico), including WECC, which is the regional entity for the region in which the ISO is located. Pursuant to those agreements, NERC delegated responsibility to the regional entities to carry out – with Commission and NERC oversight – compliance monitoring and enforcement of the mandatory, Commission-approved Reliability Standards.[9]

[6] FERC Order Paragraph 1417: CAISO will "as of the effective date of MRTU Release 1, commence filing post-implementation performance reports on a quarterly basis within 30 days of the end of each calendar quarter. CAISO will include the following:
1) A demonstration of compliance with NERC reliability standards:
2) An assessment of the system's ability to meet the ancillary service control, capability and availability standards set forth in MRTU Tariff sections 8.4.2, 8.4.3, 8.4.4. "
This section describes the proposed contents of the assessment that supports #1.
[7] 16 U.S.C. § 824o.
[8] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[9] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

The Commission has emphasized the comprehensive nature of the compliance regime it has approved in its orders since 2006:

> [C]ompliance monitoring must occur on an ongoing and proactive basis. Due to the preventive aspect of section 215 [of the FPA] and the requirements of the Reliability Standards, compliance monitoring and enforcement of the Reliability Standards are not triggered only by a past event or a cyber security incident. The ERO and Regional Entities have several proactive monitoring processes, including, but not limited to, spot checks and audits, to verify that users, owners and operators are in compliance with the Reliability Standards and to maintain the reliable operation of the Bulk-Power System.[10]

In accordance with this compliance regime, the Commission's regulations require the ERO and each regional entity to "have an audit program that provides for rigorous audits of compliance with Reliability Standards by users, owners and operators of the Bulk-Power System."[11] The Commission has provided guidance to NERC and the regional entities regarding the conduct of their compliance audit processes. The Commission's regulations also require the ERO and each regional entity to "have procedures to report promptly to the Commission any self-reported violation or investigation of a violation or an alleged violation of a Reliability Standard and its eventual disposition."[12] As noted in the Commission order quoted above, NERC and the regional entities employ a variety of methods to monitor, assess, and enforce compliance with the Reliability Standards. For example, the WECC Compliance Monitoring and Enforcement Program ("CMEP") employs eight processes to collect information in order to make assessments of compliance by entities such as the ISO: (1) compliance audits; (2) self-certifications by owners, users, and operators of the bulk power system; (3) spot checking; (4) compliance violation investigations; (5) self-reporting by bulk-power system owners, users, and operators of specific incidents and events; (6) periodic data submittals; (7) exception reporting; and (8) complaints (*i.e.*, information received from other industry participants).[13]

The ISO is subject to this comprehensive compliance regime. Indeed, a significant portion of all activities undertaken by the ISO is devoted to ensuring compliance with the Reliability Standards. An audit of the ISO's program to ensure compliance with NERC reliability standards by WECC is scheduled for October 2009 and the Commission has access to the ISO's compliance

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[10] *North American Electric Reliability Corp.*, 126 FERC ¶ 61,229, at P 9 (2009).
[11] 18 C.F.R. § 39.4(a).
[12] 18 C.F.R. § 39.4(b).
[13] *See* "WECC Compliance Monitoring and Enforcement Program," at § 4.1 (available on NERC's website at: http://www.nerc.com/files/WECC_2009_Implementation_Plan.pdf); http://compliance.wecc.biz/Application/ContentPageView.aspx?ContentID=74 (WECC web page regarding the CEMP).

information pursuant to Section 215 of the FPA and the Commission-approved NERC Rules of Procedure.[14]

As an example of compliance with mandatory Reliability Standards, ISO management prepares an Operations Highlights Report for each meeting of the Board of Governors. This report illustrates the compliance of current ISO operations with NERC Reliability Standards regarding reliable grid operations. In particular, the Operations Highlights Report contains data indicating that, for the first three months of operations under MRTU, the ISO satisfied NERC's Control Performance Standard ("CPS") 1, which is a statistical measure of Area Control Area ("ACE") variability, CPS 2, which is a statistical measure of ACE magnitude, and NERC's Disturbance Control Standard ("DCS"), which is used to determine the number of significant internal and external system disturbances. CPS 1 and CPS 2 measure compliance with NERC Reliability Standard BAL-001-0.1a (entitled Real Power Balancing Standard Performance) and DCS measures compliance with NERC Reliability Standard BAL-002-0 (entitled Disturbance Control Performance). Under NERC Reliability Standard BAL-001-0.1a, a CPS 1 percentage of at least 100% and a CPS 2 percentage of at least 90% are required for full compliance. Data through the end of June demonstrates that the ISO has operated the grid in compliance with these Reliability Standards.[15]

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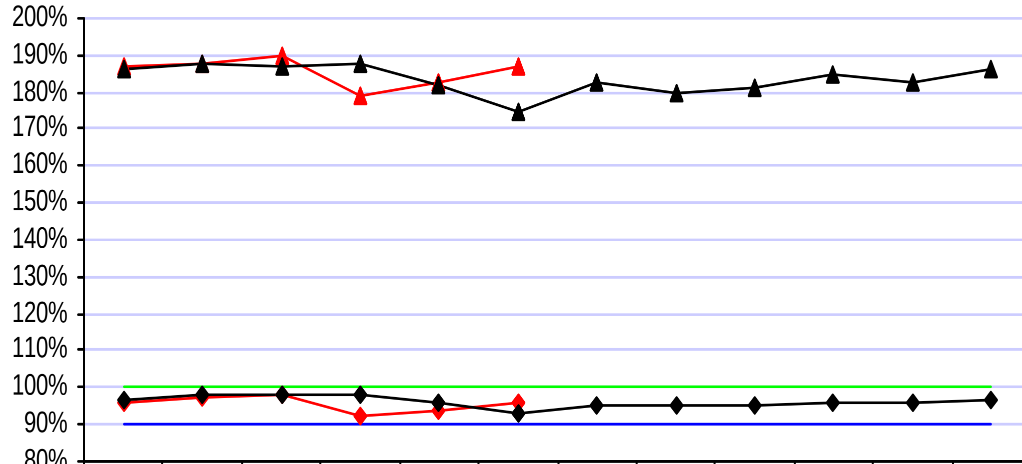
[14] *See* NERC Rules of Procedure, Section 1505(1) ("A request from FERC for reliability information with respect to owners, operators, and users of the bulk power system within the United States is authorized by Section 215 of the Federal Power Act.").

15 Data in Figure 17 and

Figure **18** are based on a presentation to the Board of Governors on July 20, 2009 which has been corrected. The percentages differ slightly from what was reported to the Board due to an underlying data error, which has now been corrected.

Figure 17 provides the CPS1 and CPS2 data for January through June 2009 as well as data for 2008 for comparison. For 2009 to date, the data show that the CPS 1 percentages were all above 100% and the CPS-2 percentages were all above 90%.

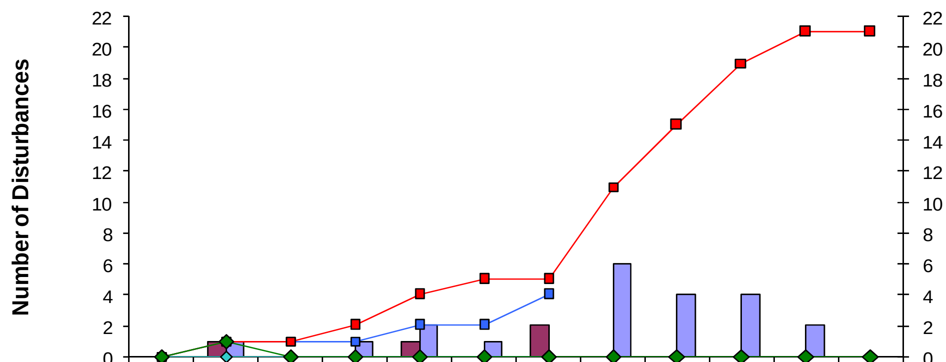
Figure 17: CPS1 and CPS2 Violations



	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
'09 CPS 1	187%	188%	190%	179%	183%	187%						
'09 CPS 2	95.76%	97.15%	97.79%	92.29%	93.68%	95.90%						
'08 CSP 1	186%	188%	187%	188%	182%	175%	183%	180%	181%	185%	183%	186%
'08 CPS 2	96.28%	98.08%	97.89%	98.31%	95.72%	92.94%	95.45%	95.42%	95.05%	96.24%	95.72%	96.50%
CPS1 Min Req	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CPS2 Min Req	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%

Figure 18 provides the DCS data for January through June 2009 as well as data for 2008 for comparison. For 2009 to date, the data show the number of DCS violations was zero.

Figure 18: 2008 and 2009 DCS Violations



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Inside ISO '09	0	1	0	0	1	0	2					
Inside ISO '08	0	1	0	1	2	1	0	6	4	4	2	0
ISO DCS Violations '09	0	0	0	0	0	0	0					
09 YTD Total	0	1	1	1	2	2	4					
08 YTD Total	0	1	1	2	4	5	5	11	15	19	21	21
ISO DCS Violations '08	0	1	0	0	0	0	0	0	0	0	0	0

Reliability – Assessment of Ancillary Service Control[16]

Ancillary Service No Pay Program

The results of the no pay program address many of the specific items raised in the FERC order that created the need for this report. In particular the following elements of the no pay program are responsive to the FERC order.

- Undelivered no pay for spin and non-spin capacity – A no pay charge amount is created if a resource fails to deliver at least 90% of energy dispatched from spin and non-spin capacity. This ensures that resources are at the dispatched operating level within 10 minutes after issuance of the dispatch Instruction [8.4.2 (b), 8.4.3(a); Footnote Item 4]
- Undispatchable no pay for spin and non-spin capacity – A no pay charge amount is created when a resource has an outage or an insufficient ramp rate and cannot provide the full amount of spin and non-spin. This ensures that resources scheduled to provide Ancillary Services are available for dispatch throughout the ensure settlement period [8.4.4i; Footnote Item 1]
- Unavailable no pay for spin and non-spin capacity – A no pay charge amount is created when a resource cannot provide spin and non-spin due to uninstructed deviations. This ensures that resources scheduled to

[16] Section Justification

FERC Order Paragraph 1417: CAISO will "as of the effective date of MRTU Release 1, commence filing post-implementation performance reports on a quarterly basis within 30 days of the end of each calendar quarter. CAISO will include the following:

1) A demonstration of compliance with NERC reliability standards:

2) An assessment of the system's ability to meet the ancillary service control, capability and availability standards set forth in MRTU Tariff sections 8.4.2, 8.4.3, 8.4.4. "

In this regard, footnote 591 to Paragraph 1417 specified five particular items (hereby designated footnote-items) associated with those MRTU Tariff sections that the ISO needs to discuss in its quarterly report:

> "In order to ensure compliance with these standards, we direct the CAISO to include an assessment of the following in its quarterly, post-implementation performance reports: (1) the generating units of each participating generator scheduled to provide spinning reserve and non-spinning reserve are available for dispatch throughout the settlement period for which they have been scheduled; (2) the generating units of each participating generator scheduled to provide spinning reserve are responsive to frequency deviations throughout the settlement period for which they have been scheduled; (3) the ability of ancillary services providers to respond to signals from the CAISO Energy Management System to provide regulation when ACE exceeds the allowable CAISO Control Area dead band for ACE; (4) each provider of spinning or non- spinning reserve can provide its resource at the dispatched operating level within ten minutes after issuance of dispatch instructions; and (5) the generating units providing voltage support have automatic voltage regulators to correct the bus voltages within the prescribed voltage limits and within the machine capability in less than one minute."

In general this section addresses item (2). Specifically the no-pay section addresses footnote items (1), (2), and (4) listed above, whilst the "ACE and Voltage Control Assessment" section addresses footnote items (3) and (5). Footnote item (3) is associated with MRTU Tariff Section 8.4.2(a) and footnote item (5) is associated with MRTU Tariff Section 8.4.2(c).

provide Ancillary Services are available for dispatch throughout the entire settlement period [8.4.4i; Footnote Item 4]

- Unconnected no pay for spin – A no pay charge amount is created when resource scheduled to provide spin is not connected to the Grid. This ensures that resources scheduled to provide spin are responsive to frequency deviations [8.4.4ii; Footnote Item 2]

Trends of Ancillary Service Non-Compliance

The data for calculating no pay is based on settlement-quality data so the results are delayed and the ISO will only report results that are finalized through the recalculation statement. Results for the months that are not included will be included in subsequent quarterly reports as they become available. Figure 19 is a trend in, daily percent, of the total spin and non-spin capacity that was not available due to one or more of the no pay categories during April 2009 as a proportion of the total spin and non-spin procured. The level of non-compliance peaked at 2.8% on the first trading date that the new ISO markets were implemented, April 1. The average level of non-compliance was 0.9% of the total spin and non-spin procured for the month of April 2009.

Figure 19: Daily Ancillary Service Non-Compliance for April 2009

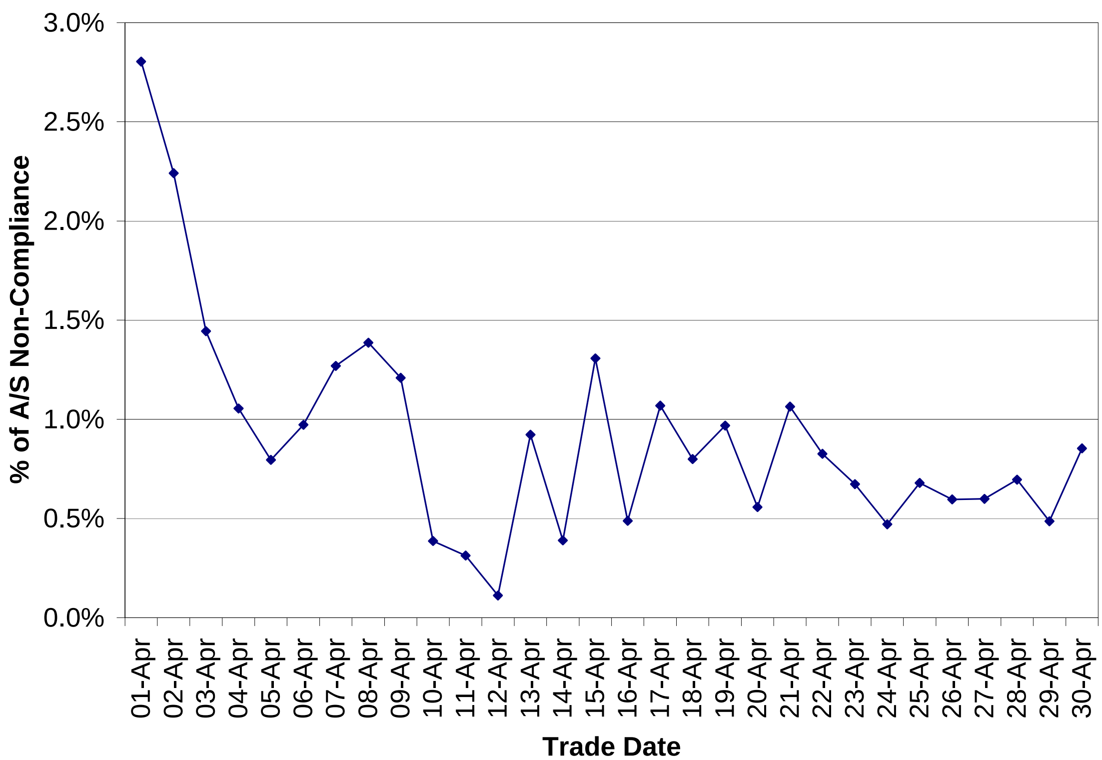
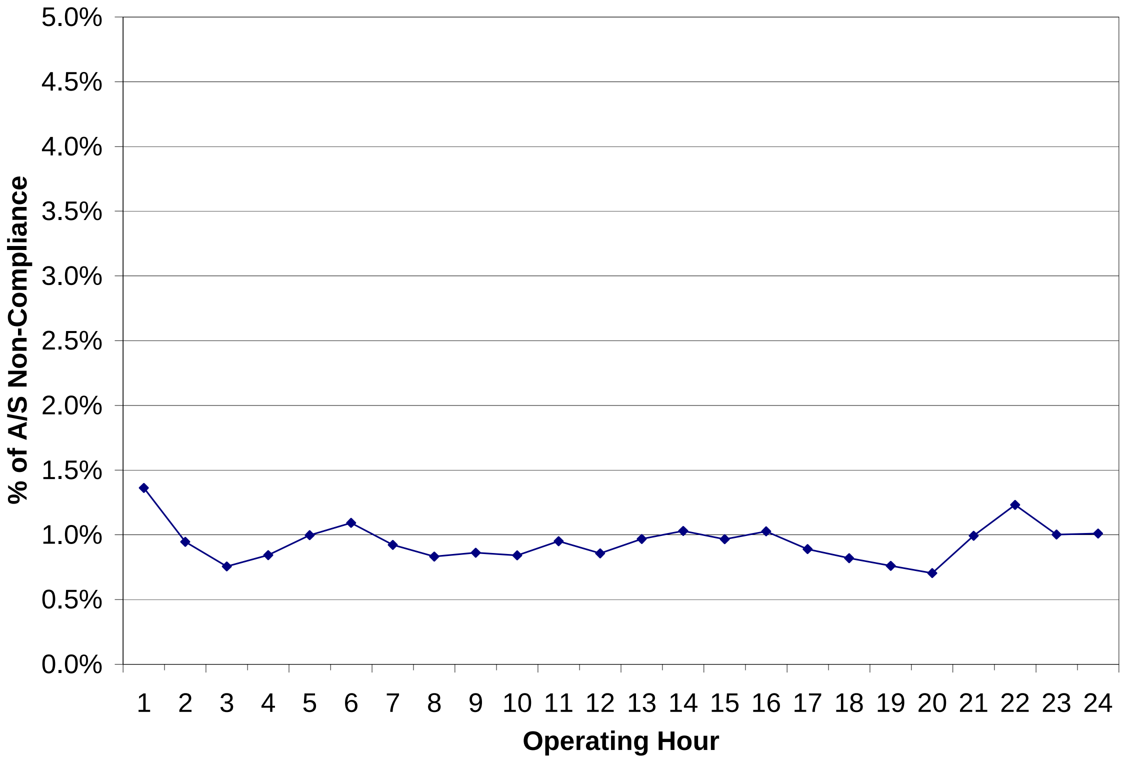


Figure 20 is an hourly trend of the same spin and non-spin data, this time shown as an hourly average percentage trend. No significant issues exist in any particular operating hour.

Figure 20: Hourly Trend of Non-Compliance in Percent



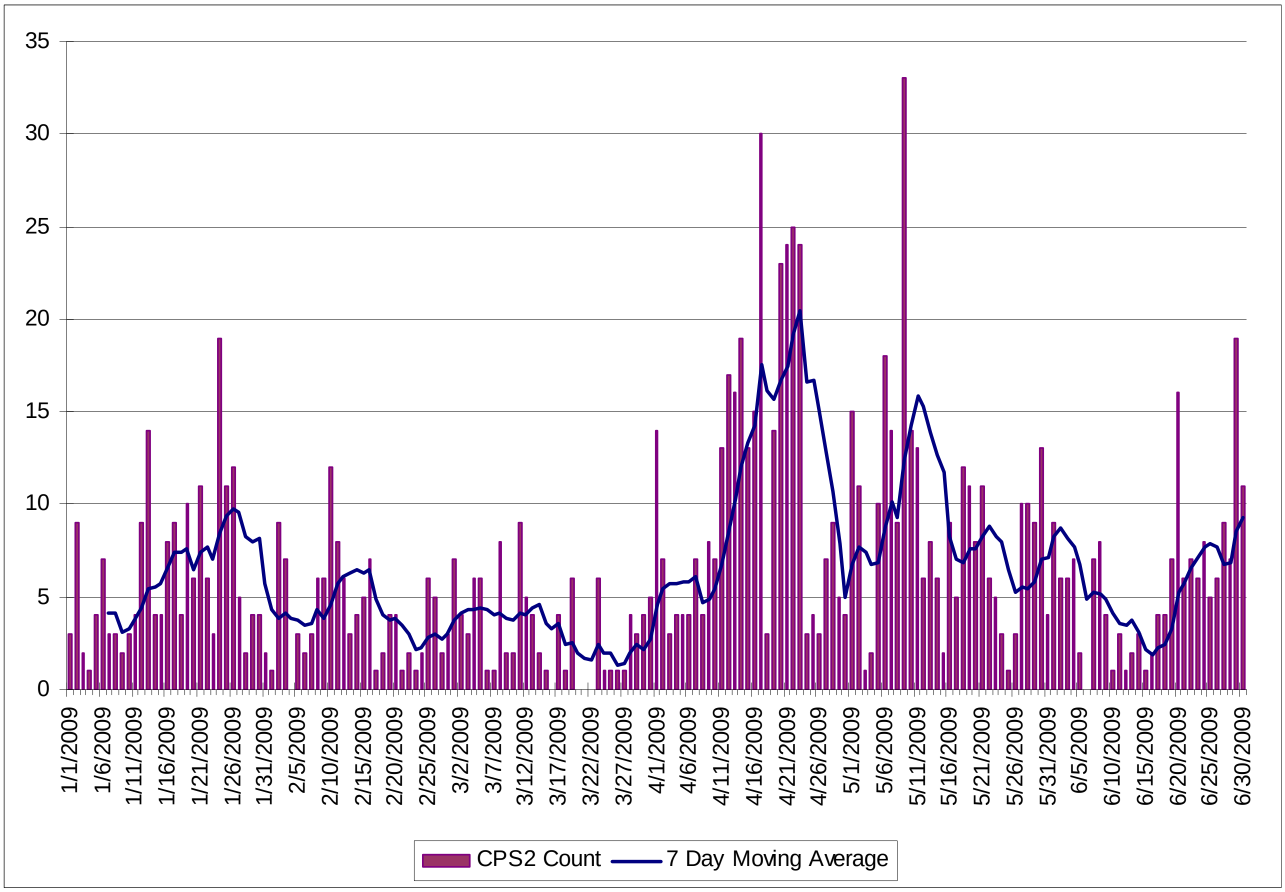
Area Control Error

The most relevant indicator that demonstrates the ability of generators "to respond to signals from the ISO Energy Management System (EMS) to provide regulation when ACE exceeds the allowable ISO Control Area dead band for ACE" is the pattern of Control Performance Standard 2 violations. The CPS2 standard is one of three standards (the others are CPS1 and DCS) that are laid down by the North American Electric Reliability Council (NERC). CPS2 is a statistical measure of ACE magnitude that is designed to limit a control area's unscheduled power flows.

Like other control areas the ISO establishes deadband thresholds above and below which our Automatic Generation Control (AGC) sends a control signal to units on regulation to reduce the ACE. Generating units respond by following control signal issued by AGC. This closed loop feedback control is designed to minimize the ACE. When the system is stressed by real-time events, such as contingencies, statistical violations are registered under the CPS2 framework.

The pattern of CPS2 violations is shown in Figure 21 below. Although there was an up tick in the number of CPS2 violations right after go-live the pattern has since moderated as the operators have gained experience with the new software systems, which in turn, have been patched and stabilized.

Figure 21: Trend in CPS2 Violations



Voltage Control Assessment

In accordance with Section 1417 of the Commission's September 2006 order, the ISO is required to provide an assessment of the system's ability to meet the ancillary service control, capability and availability standards set forth in MRTU Tariff sections 8.4.2. Specifically, the Commission asked the ISO to provide an assessment as to the requirement set forth in Section 8.4.2(c) which specifies that "generating units providing voltage support have automatic voltage regulators to correct the bus voltages within the prescribed voltage limits and within the machine capability in less than one minute."[17]

The ISO ensures that new generators satisfy Voltage Support requirements set forth in tariff Sections 8.4.2(c) as part of the generator interconnection process.

[17] September 21, 2006 Order at n. 59.

For ongoing compliance, the ISO relies on NERC reliability standard (VAR-002-1) which states the following:

> "R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator."

In addition, the ISO has the authority to audit Voltage Support performance pursuant to Section 8.9.12.

The ISO is not aware of any evidence to suggest that the change to the new market design has impaired resources ability to satisfy the Voltage Support tariff requirements.

Business Practice Manuals (PRRs)[18]

For the quarter ending June 30, 2009, no BPM PRR reports were delivered to the ISO Board of Governors because there was no information in the BPM change management system to report to the Board at its May, 2009 meeting and there was no Board meeting in June, 2009.

[18] In accordance with a commitment the ISO made in the transmittal letter (at page 39) for its August 3, 2007, compliance filing in Docket Nos. ER06-615-011 and ER07-1257-000, which filing the Commission subsequently accepted, this section includes all Business Practice Manual (BPM) Proposed Revision Request (PRR) reports delivered to the ISO Board of Governors during the relevant quarter.

Bilateral Transfers of Existing Contract Import Capability[19]

Table 5 below describes the bilateral transfers of RA import capability. All reported activities are for Pre-RA Import Commitment Capability capacity. This information is also publicly posted at:
http://www.caiso.com/2396/239679bc505e0.pdf
The referenced Tariff Section also requires the ISO to notify FERC of any transfer information received pursuant to Step 8 of the ISO Tariff Section 40.4.6.2.1. No such information was received this quarter.

Table 5: Transfer Notifications of Existing Contract Import Capability

Start	*End*	*Transferor / Transferee*	*Branch Group*	*MW*	*Price per MW/Mth*
01/01/09	02/28/09	Shell Energy / Pilot	CFE Branch Group	66	$1,500
07/01/09	09/30/09	Shell Energy / Pilot	CFE Branch Group	5	$2,500
07/01/11	09/30/11	Shell Energy / Golden State Water Company	CFE Branch Group	18	$2,500
05/01/09	07/31/09	Shell Energy / 3 Phases	CFE Branch Group	1	$2,000
08/01/09	09/30/09	Shell Energy / 3 Phases	CFE Branch Group	2	$2,000
10/01/09	10/31/09	Shell Energy / 3 Phases	CFE Branch Group	1	$2,000
01/01/09	02/28/09	Shell Energy / 3 Phases	CFE Branch Group	6	$1,750
08/01/09	08/31/09	Shell Energy / Calpine	CFE Branch Group	11	$1,500
09/01/09	09/30/09	Shell Energy / Calpine	CFE Branch Group	11	$1,500
07/01/09	07/31/09	Shell Energy / Navy/Wapa	CFE Branch Group	12	$1,850
05/01/09	12/31/09	Shell Energy / 3 Phases	CFE Branch Group	6	$1,750
05/01/09	12/31/09	Shell Energy / Pilot	CFE Branch Group	66	$1,500
01/01/09	01/31/09	Shell Energy / Constellation	CFE Branch Group	8	$850
02/01/09	02/28/09	Shell Energy / Constellation	CFE Branch Group	6	$850
02/01/09	02/28/09	Shell Energy / NRG	CFE Branch Group	2	$1,100

[19] In accordance with section 40.4.6.2.2.2, the CAISO must report to the Commission, on quarterly basis, all bilateral transfers of RA import capability. This section provides the relevant information.

Aggregate Data on Interim Scheduling Charges[20]

The reporting period for this report is April 1st to June 30th 2009, and is submitted with the Commission on July 30, 2009. At the time of submission, the full settlements process has not completed. Therefore, this report only includes data for the month of April based on the April 2009 Monthly Recalculation statement. Subsequent reports will provide this data as it becomes available.

During the month of April only one Schedule Coordinator was assessed a penalty. This occurred on April 20, 2009, for three Trading Hours. This penalty was levied in accordance with ISO Tariff Section 11.24.2 (a) which provides that a penalty will be assessed when the total net negative CAISO demand deviation is greater than fifteen percent (15%) and less than twenty percent (20%) of the maximum of the Scheduling Coordinator's cleared total CAISO demand as represented in its Day-Ahead Schedule in its applicable LAP or its submitted Self-Schedule in its applicable LAP. The total penalty levied was $11,111.40 and the amount of the deviation was 74.07 MW.

Section 11.24.2 (b) requires that a higher penalty be invoked when the net negative CAISO demand deviation is greater than or equal to twenty percent (20%) of the maximum of the Scheduling Coordinator's cleared total CAISO demand as represented in its Day-Ahead Schedule in its applicable LAP or its submitted Self-Schedule in its applicable LAP. This was not applied during the month of April.

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[20] As per Paragraph 37 of the Commission's July 17, 2008, order in Docket No. ER06-615-013, 124 FERC ¶ 61,043, the CAISO will report aggregate data on interim scheduling charges. This section reports the Under-Scheduled Load (USL) penalty assessed to scheduling coordinators.

Deferred Functionality Items[21]

The ISO is committed to resolving the deferred functionality items and incorporating the four deferred items into the 2009-2011 release plans. The timing of the deployment of each item is dependent on the level of effort required and the number of areas affected. In some cases, the ISO will need to seek stakeholder input before the market design and business requirements can be finalized. The ISO also seeks to optimize these efforts with other market initiatives already planned to take advantage of testing efficiencies and other considerations where resources could be constrained.

1. Forbidden Operating Region

Prior to go live, the Commission approved the deferral of functionality that enabled the ISO to not dispatch resources in the Real-Time within their Forbidden Operating Region. The ISO is seeking to incorporate this functionality in an initiative to implement Multi-Stage Generator Modeling (MSG). The final proposal for MSG initiative was approved by the ISO Board of Governors in May 2009. The MSG functionality is currently scheduled to be deployed in February 2010.

2. Limitations Changes in Operational Ramp Rates

Prior to go live, the Commission approved the imposition of limitations on the number of Operational Ramp Rate changes within a given interval a generating unit may submit. The ISO is currently addressing this functionality in the context of two other related changes: (1) Simplified Ramping, which in part is expected to improve performance and (2) Multi-Stage Generator Modeling, which will more explicitly address the resource operational characteristics that result in resources attempting to use low ramp-rates to reflect slow transition times between operational states of the resource. The Simplified Ramping functionality will be deployed in the post-summer 2009 timeframe. The Multi-Stage Generator Modeling is currently scheduled for 2/1/2010.

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[21] In accordance with the January 30, 2009 Deferred Items Order at P 4, 30, 41, 58, the Commission requires that the CAISO report on the status of the CAISO's efforts to resolve and restore the four deferred functionalities in this quarterly report. The four functionalities are

1. Enforcement of Forbidden Operating Region constraints for generating units in the real-time market;
2. Unlimited Operational Ramp Rate changes for generating units;
3. Procurement of incremental ancillary services in the Hour-Ahead Scheduling Process; and
4. Automation of the commitment process for extremely long-start resources.

The CAISO is further ordered to lay out a timeframe in which each of the functionalities can be restored and implemented. This section provides the relevant information.

3. Procurement of Ancillary Services in the HASP
The ISO intends to complete a stakeholder process to consider the reversion to procurement of Ancillary Services in HASP. If this process results in changes in the design and requires amendments to the tariff other than simple reversion to the previously filed tariff, the ISO will submit any such proposed changes to the Board of Governors and for will seek Commission- approval in the fall of 2009 time period. A deployment schedule will be determined following the stakeholder process as necessary.

4. Extremely Long Start Process
The ISO has determined that the automation of the commitment process for extremely long-start resource may be of limited value once as we are reliably operating through the summer of 2009 and have the ability to manually dispatch these resources through the Exceptional Dispatch process. The ISO is instead seeking to incorporate this functionality into an initiative to resolve multi-day unit commitment on a permanent basis. This functionality also requires stakeholder input and the ISO intends to bring a final proposal to the ISO Board of Governors in the fall of 2009 timeframe. A deployment schedule will be determined following the stakeholder process.

Evaluation of Uneconomic Adjustment Parameters[22]

Day-Ahead Market

The majority of the market parameters that are used for adjusting non-priced quantities in the day-ahead market optimization relate to transmission constraint relaxation, adjustment of self-schedules and relaxation of ancillary service procurement requirements. As discussed more fully below, since the start-up of LMP-based markets on April 1, 2009, only in rare instances have these parameters affected the market results. Market conditions have been such that the IFM did not in any instance reduce self-schedules for internal default LAP demand. Primarily during the initial days of the LMP-based markets, in some instances self-schedules for generation and interties were adjusted as a result of self-schedule volumes exceeding the capacity of intertie constraints or the ratings of radial, local transmission systems. The market optimization manages such constraints by: 1) representing the supply self-schedules with an "uneconomic" bid segment price of -$550/MWh for establishing resource schedules in the scheduling run; 2) determining the MW amount by which these schedules have been adjusted using the uneconomic scheduling run bid prices, and 3) then for establishing market prices, using an uneconomic bid segment priced at -$30/MWh between the original self-schedule and the adjusted self-schedule minus a small quantity known as "epsilon." This mechanism produces LMPs equal to or less than -$30/MWh at the location of each reduced resource self-schedule. The ISO's review of market results to date confirms that this mechanism is functioning as intended, with self-schedules for generation and imports being adjusted to conform to transmission limits, and being priced at $-30/MWh. [23]

In instances where the need to resolve congestion has required the relaxation of transmission constraints, the market optimization resolves these constraints by: 1) pricing violations of internal transmission constraints at $5000/MW in the scheduling run,[24] 2) determining the amount by which these constraints have been relaxed, and 3) then, to prevent further relaxation, pricing the transmission

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[22] In its February 19, 2009 Parameters Order, (126 FERC ¶ 61,147 at P 82) FERC said:

> "Moreover, the CAISO has committed to continually evaluate the parameters in the future, both before and after the MRTU "go-live" date. We expect the CAISO to follow through on its commitment. We find the CAISO's proposed parameter levels to be just and reasonable

From the CAISO's parameter answer:

> "In conjunction with those [quarterly] reports the CAISO will provide sufficient meaningful analysis of each quarter's observations with respect to adjustment of non-priced quantities and the performance of the parameter settings."

[23] Bid segment prices more negative than the -$30 were established to apply to the submitted self-schedules of Existing Transmission Contracts, Transmission Ownership Rights, Converted Rights and Regulatory Must Take resources. In the first quarter the volume of these self-schedules has not exceeded the available transmission capacity in the DAM.

[24] For intertie constraints a price of $7000/MWh is used for relaxation in the scheduling run.

constraint violation between the original limit and the adjusted limit plus epsilon at $500/MWh in the pricing run.

The ISO assessed the effectiveness of the selected levels of these parameters in ensuring that transmission constraints would be appropriately enforced while ensuring reasonable market prices by examining the instances in which transmission constraints have had the highest shadow prices. The following constraints have been subject to shadow prices in excess of $500/MWh in the Day Ahead Market during April, May and June of 2009:

- The East Nicolas to Rio Oso 115 kV line was relaxed by 0.2 MW on May 2, 2009, producing a pricing run shadow price of $4740.65/MWh; and was relaxed by 0.8 MW on May 14, 2009, producing a pricing run shadow price of $500/MWh. On days when constraint relaxation was not necessary, this constraint's shadow price reached $1117.38/MWh on May 12, 2009, and $1071.43/MWh on May 14, 2009, in both the scheduling and pricing runs.
- The Prunedale Junction to Moss Landing 115 kV line had a maximum shadow price of $5000/MWh in the scheduling run on June 29, 2009, which was reduced to $500/MWh in the pricing run. Because there were no resources that were at least 2% effective in mitigating this constraint, the 2% effectiveness threshold prevented the optimization from seeking further congestion relief and instead relaxed this constraint for a violation of 15 MW in one hour, and 2.7 MW in another hour.
- The Contra Costa to Rossmore Tap 230 kV line had a maximum shadow price of $4371/MWh in the scheduling run on April 22, 2009, without constraint relaxation. Adjustments to self-schedules produced a maximum shadow price of $802.15/MWh in the pricing run.
- The Palermo to Honcut Junction 115 kV line had a maximum shadow price on May 2, 2009, of $725.71/MWh, and was enforced without relaxation.

As reflected in Section 27.4.3.6 of the ISO tariff, the ISO Market software includes a minimum shift factor or “effectiveness” threshold setting which excludes resources below the threshold with respect to any given constraint from being used to provide congestion relief on that constraint.
This threshold is set at two percent (2%). The 2% level was chosen to allow the optimization to have reasonable opportunities to dispatch resources to manage transmission constraints, while minimizing large adjustments to resources that are minimally effective in managing constraints. For the East Nicolas to Rio Oso 115 kV constraint, the most effective resources have shift factors of approximately 4.9%. For the Palermo to Honcut Junction 115 kV line, the most effective resources also have shift factors of approximately 4.9%. In some hours for these constraints, the most effective available resource have had 4.0% effectiveness, and adjustments to some resources as low as 3.2% have been needed in order to manage the constraints. This is why we see pricing run

shadow prices that differ from the $500/MWh pricing run parameter and instead reflect the actual cost of re-dispatching resources to relieve congestion. In contrast, for the Prunedale Junction to Moss Landing 115 kV line, the most effective resources have shift factors of approximately 0.3%, and are remote from this constraint, so they are not considered to be reasonable options for managing this constraint, and hence the pricing run shadow price goes to the $500/MWh value.

Given the circumstances described above, the ISO believes that the current parameter values have been effective in adjusting self-schedules and managing the relaxation of transmission constraints, and have produced reasonable market results in the Day Ahead Market. In the one instance to date of a constraint for which no resources are more than 2% effective, the most effective available resources are significantly less than 2% effective and are not operationally reasonable choices for managing the constraint. The ISO has monitored the relationship between the 2% shift factor threshold and the Default LAP prices, which are determined based on the weighted average of the constituent PNodes. A concern was raised that the weighted average price could be inconsistent with the price of the dispatched level of the LAP load. Starting May 15, 2009, the ISO began to provide both the APNode and Anode prices for comparison (see link http://www.caiso.com/23af/23afd80e2ddb0.html). The ISO continues to analyze this data

Real-Time Market

Since the implementation of the new markets, there have not been a significant amount of uneconomic schedule adjustments of adjustments of non-priced quantites in the real-time market. Uneconomic adjustments or adjustment of non-priced quantities occur in the real-time market optimization when there is insufficient amount of economic bids to obtain a feasible and reasonable solution. The following provides an assessment of the non-priced quantity parameters that have been in place since April 1. It should be noted that unless a market participant explicitly submits an economic bid in the RTM for the RTM to use to dispatch the resource below its Day-Ahead Schedule for energy , the Day-Ahead energy Scheduled amount is effectively a self-schedule in the Real-Time Market and has a scheduling run price below -$500/MWh that governs any reductions. Such reductions typically become necessary when a transmission derate occurs between the DAM and the RTM, such that accepted schedules in the DAM are no longer feasible in real-time.

Real-Time Dispatch (RTD)

RTD is executed every 5 minutes and dispatches generating resources to meet load variations in real-time. During the three-month period from April 1 to June 30, 15.53% of the intervals had one or more uneconomic adjustments in the RTD market solution. Uneconomic adjustments in RTD include:

- Supply energy self-schedule curtailments (internal generation and imports),
- Export energy self-schedule curtailments, and
- Relaxation of transmission constraints including flowgates and nomograms.

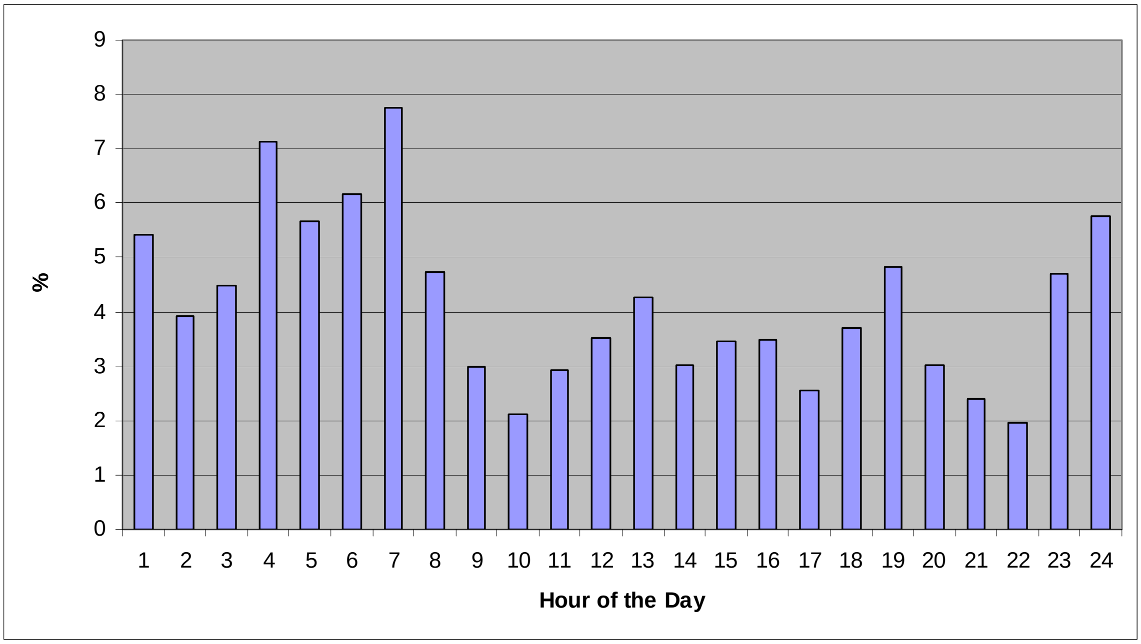
Supply energy self-schedule curtailment in RTD can occur due to system-wide over-generation, over-generation in a small generation pocket or large congestion area, or insufficient effective economic bids on the decremental side of a congested transmission constraint. The RTD self-schedule penalty price for the scheduling run is set at -$1600 for the lowest priority self-schedule curtailments of generation and imports and becomes more negative for other self-schedules that have a higher priority for protection. Imports are scheduled on hourly basis in day-ahead and in HASP (hour ahead scheduling process) and are modeled as self- scheduled resources in RTD. The RTD software has been designed so that import energy that cleared HASP can be adjusted if necessary to obtain a market solution, even though such adjustment will not be carried out in actual operation under normal circumstances but does provide the operator information in case manual action is necessary. Subsequently, in the pricing run, the associated pricing parameter is set to -$30/MWh, the bid decremental bid cap, and is used to price the self-schedule curtailment of the supply resource.

The ISO's analysis of the first quarter of operation of the new markets has found that the initial energy self-schedule parameter settings in RTD have been largely appropriate. First quarter results show that:

1. Self-schedule curtailments of generating resources and imports did not occur very often to resolve the constraint violations.
2. Among those intervals with self-schedule curtailments, in most instances the pricing run system LAP (system load aggregation point) and DLAP (default load aggregation point including PG&E, SCE and SDG&E) prices were near or above the -$30/MWh bid floor level. During periods of system-wide or large congestion area over-generation, the pricing run system LAP price and/or DLAP prices were usually around -$30/WMh. On the other hand, resolving congestion of local transmission constraints has resulted in limited locations within the system with negative LMPs in the pricing run and DLAP prices significantly above the -$30/MWh level.
3. In rare instances, DLAP prices or system LAP prices in the pricing run have been significantly lower than -$30/MWh due as the price was set by a constrained upward ramping resource during a system-wide or large area over-generation situation.

Data analysis of the RTD market results shows that uneconomic adjustments occurred in 10.48% of the 5-minute intervals: 33.45% of the uneconomic adjustments occurred in April; 37.13% in May; and 29.41% in June. Figure 22 shows the curtailments as a percentage of the total occurrences for different hours of day over the 3-month period. The chart indicates that off-peak hours where over-generation occurs more frequently are more likely to have instances of supply energy self-schedule curtailment.

Figure 22: Percentage of Supply Energy Uneconomic Adjustment Curtailments by Hour



Among the self-schedule curtailment intervals, over-generation system-wide or in large congestion areas occurred 61.72 % of time (or 6.47% in the 3-month period). During these intervals, LAP prices of the over-generation area were near –$30 for 86.45% of time (or 5.6% of the 3-month period) and only 13.45% (or 0.87% of the 3-month period) LAP prices were more negative than -$40. During the remaining intervals with energy supply self-schedule curtailment for resolving local congestion only; DLAP prices were well above –$30.

Export energy self-schedule curtailment in RTD can be caused by a system-wide supply-shortage, a supply-shortage in small generation pocket or even large congestion area, or by insufficient economic bids on the incremental side of a congested transmission constraint. Export hourly schedules are determined in the day-ahead market and HASP. Exports schedules do not have economic bids in RTD and are modeled as self-schedules. A penalty price of $1600 is used for uneconomic adjustments of export self-schedules to achieve a market solution. However, the export adjustment will not be carried out in actual operation under normal circumstances but does provide the operator information in case manual action is necessary. A higher penalty price is used for other higher priority export energy self-schedules. The pricing run pricing parameter is set at $500, the current bid cap, and is used to set the price for the self-schedule curtailment of the export resource.

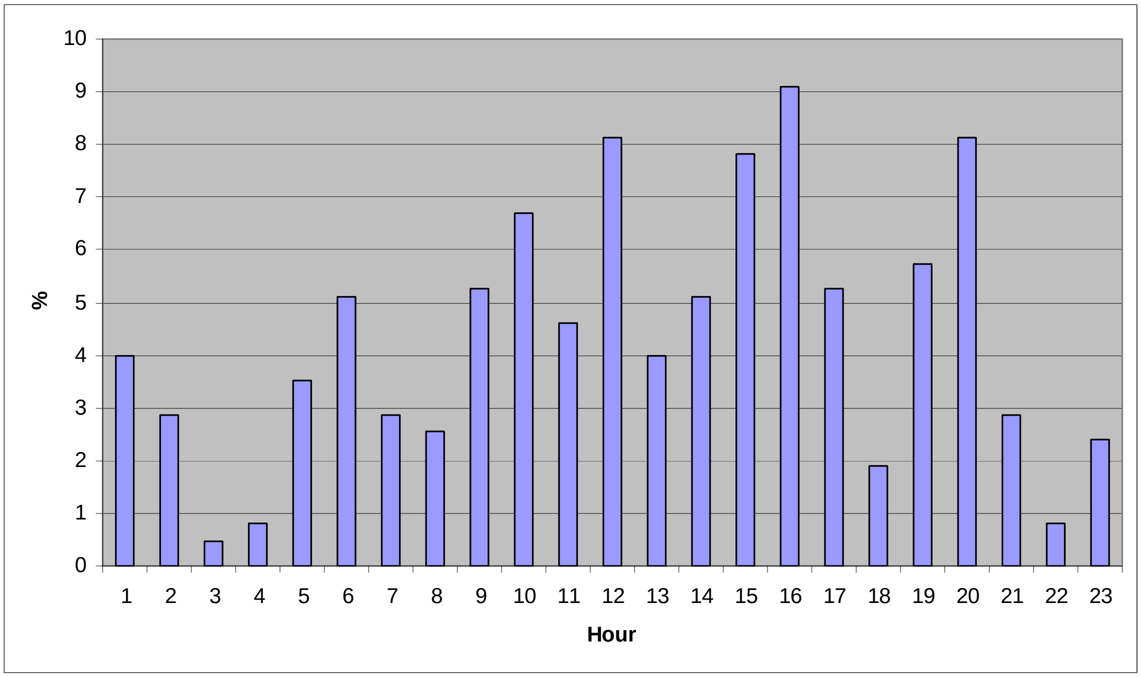
The ISO's first quarter analysis shows that the initial export self-schedule curtailment parameters have also been appropriate because:

1. Self-schedule curtailment of exports has rarely occurred.
2. In those instances where there were export self-schedule curtailments, slightly more than half of the intervals had pricing run LMPs not significantly above the $500 bid cap. Among such instances, pricing run system LAP and/or DLAP prices around $500 indicated a system wide or large congestion area supply shortage. On the other hand, when resolving congestion of a local transmission constraint, the pricing run LMPs could have values above the $500 level in localized areas but the resulting DLAP prices were well below the $500 level.
3. In those instances where there was export self-schedule curtailment, slightly less than half of the intervals had some DLAP prices of at least $100 above the $500 bid cap when a downward ramping constrained resource set the price under a system-wide or large congestion area supply shortage scenario. However, there were only a small number of occurrences of export energy self-schedule curtailment over the 3-month period.

The ISO's analysis found that only 2.39% of the RTD intervals had export energy uneconomic adjustments. Of those intervals, 52.31%, 35.25% and12.44% occurred in April, May and June respectively.

Figure 23 shows the hourly adjustment occurrences (in term of time interval) in % of total adjustment occurrences over the 3-month period. The chart indicates that the peak hours are more likely to have export energy self-schedule uneconomic curtailments.

Figure 23: Percentage of Export Energy Uneconomic Adjustments by Hour



Among the self-schedule curtailments in RTD, supply-shortage system-wide or in a large congestion area occurred 82.30% of time (or 1.97% over the 3-month period). Among all the supply-shortage 5-minute intervals, LAP prices in the supply-shortage area were around $500/MWh 46.70% of time (or 0.92% over the 3 month period) and above the $600/MWh level 53.30% of time (or 1.05% over the 3-month period). For the remaining curtailment intervals where curtailments were used to resolve congestion, DLAP prices were significantly below the $500/MWh bid cap.

Transmission constraint relaxation is usually driven by a system event such as a major outage of a transmission line, transformer bank or generation resource. Transmission constraint relaxation in RTD can be caused by a supply shortage in a large congestion area that requires extra energy to flow from another area after running out of export curtailments from the area for a market solution. It can also occur when the market optimization has insufficient effective economic incremental and/or decremental bids and/or ramping capability to resolve local transmission constraint violations.

Transmission constraints include flowgate and nomogram limits in addition to thermal line limits. The market optimization uses a penalty price of $5000/MWh to relax transmission constraints in the scheduling run to provide transmission constraints a higher priority over energy self-schedule curtailments. The pricing run pricing parameter for transmission constraint relaxation is $500/MWh, the bid cap.

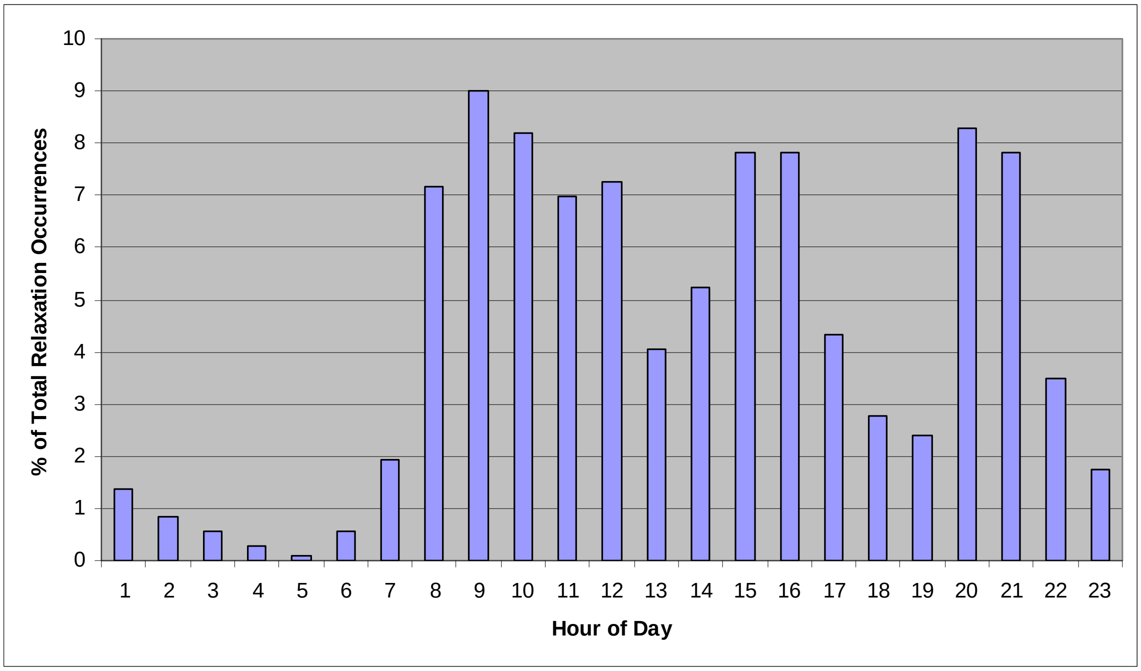
The ISO's analysis of transmission constraint relaxation during the first quarter shows that the initial parameter settings have performed as anticipated. Specifically the ISO has found that:

1. Transmission constraint relaxation occurred infrequently and, when it did occur, the amount of relaxation was small in most cases.
2. Among those intervals with transmission constraint relaxation, LMPs around the constraint were often set beyond the bid cap range of -$30/MWh to $500/MWh. However, DLAP prices are well within the range.
3. In rare instances of large congestion area supply shortage that required transmission constraint relaxation to bring in extra energy into the shortage area for a market solution, where DLAP prices would be expected in the $500/MWh range, on several occasions the pricing run DLAP prices in the shortage area rose to very high levels in the $2000/MWh to $5000/MWh range.

The RTD results show that transmission constraint relaxation occurred in 4.15% of the 5-minute intervals of which 52.89%, 31.74% and 16.38% occurred in April, May and June respectively.

Transmission constraint relaxation in the market solution has dropped noticeably over the 3-month period since the new market startup on April 1. Figure 24 shows the hourly transmission constraint relaxation occurrences in percentage occurrences. The chart shows that transmission constraint relaxation in the market solution is more likely to occur during peak-hour intervals.

Figure 24: Hourly Transmission Constraint Relaxation



It should be noted that over-generation in a large congestion area will not be resolved by transmission constraint relaxation but rather by energy self-schedule curtailment due to the fact that the energy self-schedule curtailment penalty price in the scheduling run is lower in magnitude than transmission constraint relaxation parameter.

Among the time intervals with transmission constraint relaxation in RTD solution, 83.44% of time (or 3.46% over the 3-month period) relaxation was due to the market software not being able to resolve local area transmission congestion through decremental and incremental generation adjustments, both economic and uneconomic. DLAP prices were within the -$30/MWh to $500/MWh range during these periods.

For the remaining 16.56% of the time when transmission constraint relaxation occurred (or 0.69% over the 3-month period), relaxation was needed for transferring energy to the supply shortage area. During large supply area shortage time intervals, very high DLAP prices of several thousand dollars were observed 0.36% of time over the 3-month period. The cause of high prices was again caused by the mathematical modeling problem described above.

Real-time Pre-Dispatch (RTPD)

RTPD is executed every 15 minutes with an optimization horizon that varies from one hour to several hours depending on the time within the hour at which the execution is performed. RTPD schedules ancillary services (AS) and energy for which AS schedules and pricing are binding for the first interval of the optimization horizon of each run. For RTPD, the parameter analysis focuses on the uneconomic adjustments relevant to meeting AS requirements. The relevant uneconomic adjustments include AS minimum requirement relaxation and energy self-schedule curtailment to create unloaded capacity for AS.

AS minimum requirement constraint relaxation is caused by a supply shortage in an AS region. The penalty price parameters for the minimum requirement relaxation for different types of AS in the scheduling run are set at $2500/MW for both regulation-up and regulation-down, and $2250/WM for spin and $2000/MW for non-spin. For the pricing run, pricing parameters for constraint relaxation is $250/MW for all AS types, which sets the floor value of the shadow price of the constraint.

During the months of April, May and June of 2009, the RTPD parameters have been largely appropriate for the following reasons:

1. AS requirement constraint relaxation has been infrequent.
2. Among the RTPD intervals with AS minimum requirement relaxation, the majority of the intervals have pricing run shadow prices of $250/MW. This indicates the relaxation of the minimum requirement.
3. In rare circumstances, the pricing run shadow price of the relaxed AS minimum requirement has been much higher than the $250/MWh due to the opportunity cost of the resource capacity that was used to provide the AS and thereby not able to sell energy under a high energy-price scenario.

The first quarter RTPD market results show that out of the 8736 15-minute intervals, AS minimum requirement relaxation occurred in only 14 intervals or 0.17% of time. Among these 14 intervals, 13 were in April, 1 occurred in May and none in June. AS requirements relaxations were limited to regulation up and regulation down. The pricing run shadow prices of the relaxed constraints are $250 for all cases.

Energy self-schedule curtailments occur to unload capacity so that it can provide AS under supply shortage situations. Uneconomic adjustments to the energy self-schedule use the parameters discussed in the RTD section above. An analysis of energy self-schedule curtailments for providing AS reveals that:

1. Energy self-scheduling curtailment for AS provision occurs infrequently.
2. Among the RTPD intervals with resource undergoing self-schedule energy curtailments for AS provision, the pricing run ASMP (AS marginal price) was not significantly above the $250/MW bid cap level.

Analysis of RTPD market results shows that out of the 8736 15-minute intervals in April, May and June, energy self-schedule curtailment for AS provision occurred in only 26 intervals or 0.30% of time. Nine of the intervals occurred in April and the remaining curtailments occurred on June 21. Out of these 26 intervals, 19 of the intervals had pricing run ASMPs in the $250/MW AS bid cap range or well below this level while in the remaining 7 intervals, the ASMP ranged from $440/MW to $950/MW.

Price Cap Use[25]

Explanation of Price Cap Use

As reflected in Section 27.1.3 of the ISO Tariff as approved by the Commission, for Settlements purposes, all LMPs, ASMPs and RUC Availability Prices for the IFM, RUC, HASP and Real-Time Market, as applicable, shall not exceed $2500 per MWh and shall not be less than negative $2500 per MWh. To achieve the price cap adjustment, the congestion loss component is corrected to affect the total LMP equaling either $2500 or -$2500 as shown in Table 6. For example:

Table 6: Price Cap Example

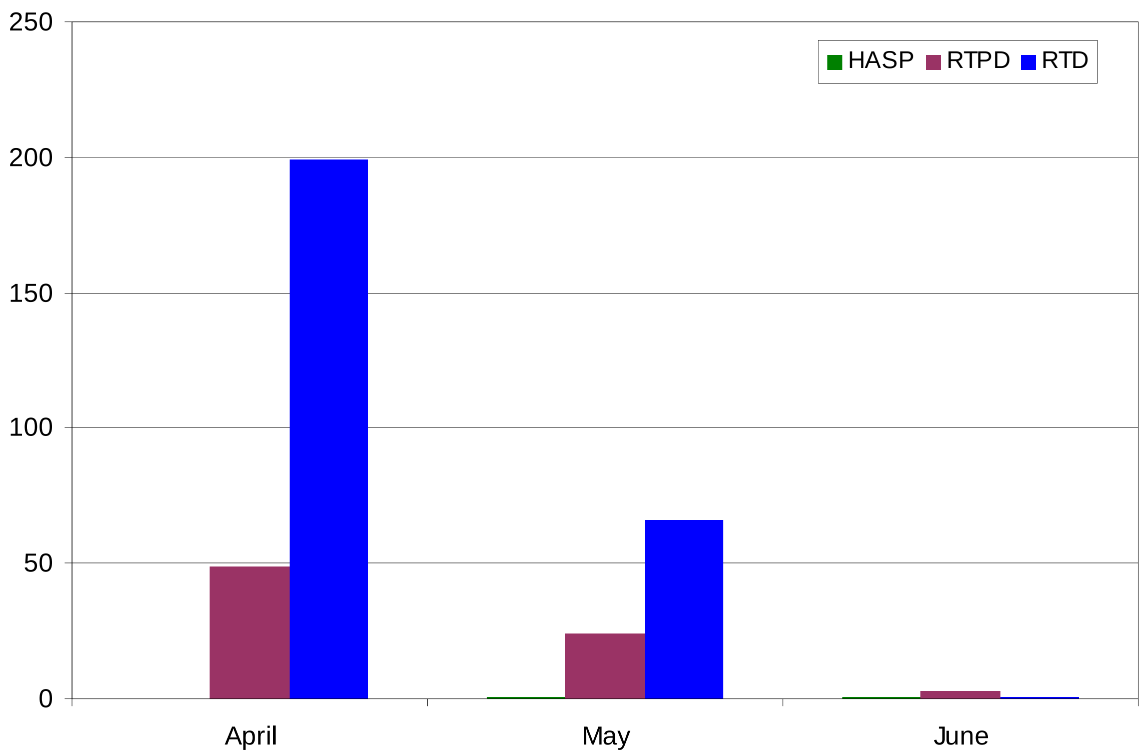
LMP Components	Original	Corrected
Energy	$2000	$2000
Congestion	$400	$300
Loss	$200	$200
LMP	$2600	$2500

[25] Per paragraph 39 of the FERC Price Cap Order (Jan 30, 2009): the CAISO states that it will be diligent in its investigation of high prices and will address the functioning of the price cap in its quarterly MRTU performance report. This section provides the relevant information.

Summary of Price Caps from April 1st through June 30th

Figure 25 shows the frequency with which the price caps were applied in the different market runs that procure products subject to the price cap from April 1st through June 30th. Four market runs procure products subject to the price cap, namely: the Day-Ahead Market (procuring energy and ancillary services, including the Residual Unit Commitment process, in the day ahead timeframe); the HASP run (procuring energy from the ties, the run starts at T-67 minutes before the top of each hour); the Real-Time Unit Commitment run (RTUC - procuring ancillary services in real-time, and run every fifteen minutes beginning in the middle of each quarter hour segment); and Real-Time Dispatch (RTD - procuring energy every five minutes and run every five minutes in real time).). In all there were 344 intervals during which the price cap was applied to prices at one or more nodes. There were no instances in which the price caps were applied in the day-ahead market.

Figure 25 Count of Price Caps



As shown in Figure 25, the number of price caps for the remaining markets followed a downward trend. In HASP, the two price caps during the time period were for inter-tie energy. RTUC price caps were for Ancillary Services and RTD price caps were for 5-minute energy.

Table 7: Summary of Price Caps

Month	HASP	RTPD	RTD
April	0	49	199
May	1	24	66
June	1	3	1
Total	2	76	266

Price Cap In Depth Analysis[26]

Price validation is a continuous process involving the review of various market runs for which review thresholds have been exceeded. Prices which fail validation may be are corrected as provided in Section 35 of the ISO Tariff. Weekly reports that describe cover the price correction activities are published at the following location: http://www.caiso.com/237b/237b797854580.html

The objective of this section of the quarterly report is to analyze the market runs where prices would have exceeded the price cap of $2,500, or the price floor of -$2,500, and were determined to be valid. Much of the analysis has already been completed and published as technical bulletins on the Technical Documentation page at http://www.caiso.com/2381/2381f87327f70.html. Where applicable the specific bulletins are referenced below.

Based on the numbers above, the ISO has determined that the prices that exceeded the price cap and price floor were generally the result of the following:

- On a nodal observation basis, congestion compounded by the lossless shift factor effect caused about 98-99% of the price excursions.
- Localized congestion involving the movement of multiple resources caused approximately 1% of price excursions
- System energy needs exacerbated by inter-temporal ramping caused less than 1% of price excursions

In recent months the absolute number of price excursions beyond the caps has declined as shown above in Figure 25.

Lossless Shift Factor Effect

The lossless shift factor effect refers to the effect of the use of lossless shift factors[27] in the ISO market, usually in resolving a radial constraint. Shift factors are used by the market in resolving congestion, where each resource is assigned a value between -1 and +1 which in general represents its effectiveness in resolving a particular constraint. The term “lossless” refers to the fact that the effectiveness factors used in the ISO market do not account for the effect of losses between their location and the congestion constraint. In the case of a radial constraint, a constraint where the resources on each side of the constraint are all equally effective at resolving it, high congestion shadow prices, in the range between the pricing run parameter for constraint relaxation and the

[26] Per paragraph 39 of the FERC Price Cap Order (Jan 30, 2009): The CAISO states that it will be diligent in its investigation of high prices and will address the functioning of the price cap in its quarterly MRTU performance reports.

[27] Shift factor is also referred to as Power Transfer Distribution Factor (PTDF) which measures the change of flow on defined transmission element as a result of an increase in injection at location relative to an equal and opposite withdrawal at a reference slack.

scheduling run parameter for constraint relaxation, can result if there is a lack of otherwise economical resources and the optimization resorts to adjusting two or more units such that small amounts of losses, and thus flow on the constraint, are reduced. This effect is explained in more detail in the following technical bulletin: http://www.caiso.com/23ce/23cec5cd70160.pdf.

The majority of cases where the lossless shift factor effect came into play were the period of April 19-24, in the San Diego area. During this time, there was a heat wave atypical of the season, along with scheduled maintenance on generation and transmission in San Diego. The transmission outages reduced the ability to import transmission into the San Diego area, and the generation maintenance reduced supply in San Diego. As the load curve went up each day, local San Diego generation struggled to meet the additional requirements. At the same time the import capability was already maxed out. Without other options the optimization moved units outside of the San Diego area in an attempt to reduce flow on the import constraint by reducing losses. A detailed analysis of one of the market results from this period is contained in the following technical bulletin: http://www.caiso.com/23b4/23b4caaf479b0.pdf

Other notable cases were: May 9, imports into San Diego limited by transmission maintenance outage; May 19, bias of path 26 in response to a real-time de-rate on the PDCI line while scheduled maintenance was occurring, detailed in technical bulletin http://www.caiso.com/23ce/23cedceb219d0.pdf; and May 29, de-rate on path 15 for scheduled maintenance.

Additionally, there were two cases where the fact that losses are being considered in the power-balance constraint but not other constraints such as Ancillary Service or ramping, similar to the lossless shift factor issue, affected prices in an over-generation condition. On May 30 and June 1, two HASP runs were resolving over-generation due to over-procurement of resources in the day-ahead market and lack of economic bids. Some units that would otherwise be economical could not be adjusted down because they were supplying Regulation Down awards. In both cases the optimization adjusted a pair of wheeling bids in an attempt to increase losses (adding load), and thus reduce the over-generation condition. In addition a similar phenomena was observed on June 5, 2009, where negative high negative prices resulted followed by high positive prices due to combination of ramping constraints and the difference in which losses are considered in the power-balance constraint and the ramping constraint. This is detailed in the following technical bulletin, http://www.caiso.com/23df/23dfbcb4677d0.pdf.

Localized Congestion Involving The Movement Of Multiple Resources

When localized congestion requires the movement of multiple resources to resolve the congestion, the the ISO observed high shadow prices. For example,

such a phenomena would reqire that in order to reduce flow on congested path A by 1 MW, unit Y must be moved up by 3 MW and unit Z must be moved down by 4 MW. The combination of two or more units moving a large amount to provide a relatively small net benefit will result in high congestion shadow prices on the system as a whole.
.

Notable cases where this occurred were: May 14, local congestion in the East Bay area due to planned maintenance; May 19, congestion in the SPTO area while recovering from a real-time de-rate on the PDCI line while scheduled maintenance was occurring, detailed in technical bulletin http://www.caiso.com/23ce/23cedceb219d0.pdf; and June 28, localized congestion in Palm Springs and the northern Sacramento valley.

System Energy Needs Affected By Inter-Temporal Ramping

In some cases, inter-temporal ramping has an effect on prices. If a resource is otherwise not marginal but is needed to supply energy needs in the binding interval, and advisory intervals indicate the same resource is no longer required and is fully ramping down over one or more intervals, then the resource may influence the price. If so, the binding interval LMP (and in turn the System Marginal Energy Cost) at the resource's location is set to be the sum of the differences between the unit's bid price and LMP over the subsequent intervals in which the unit is ramping.

On April 28 and May 27 there were a handful of intervals where this effect was observed. In all cases a slow ramping unit was needed to meet energy needs in the binding interval, and then over several advisory intervals of the same run it was ramped down to its economic point. For these intervals, the System Marginal Energy Cost was in the range of $1,500 to $2,000. Some prices exceeded the cap because of high loss components and congestion in the Humboldt area on April 28, and high loss components for a handful of pnodes in coastal Mendocino County on May 27.

Attachment B
DMM Quarterly Report

California Independent
System Operator Corporation

California ISO

Quarterly Report on MRTU Market Design Issues

July 30, 2009

Prepared by: Department of Market Monitoring

Overview

This report addresses two issues that the Federal Energy Regulatory Commission (Commission or FERC) directed the Department of Market Monitoring (DMM) to address in DMM's quarterly reports to be filed with FERC after implementation of the ISO's new market design:

- Use of Forecasted versus Bid-in Load in the Local Market Power Mitigation (LMPM) procedures performed prior to the ISO's day-ahead Integrated Forward Market (IFM); and
- Mitigation of units not under Resource Adequacy or Reliability Must-Run contracts, and the resulting eligibility of these units as Frequently Mitigated Units

Use of Forecasted versus Bid-in Load in pre-IFM LMPM

Background

In the ISO's May 2005 MRTU FERC filing, the ISO proposed to base the pre-IFM Market Power Mitigation runs on its forecast of demand, rather than demand bids submitted to the IFM. The Commission initially approved this approach, but, in its September 2005 MRTU Order on Rehearing, directed the ISO to base the pre-IFM Market Power Mitigation runs on bid-in demand, citing concerns expressed by some stakeholders that the use of forecasted demand could result in over-mitigation of supply in the IFM.[1] In a subsequent filing, the ISO requested that the Commission allow the ISO to base the pre-IFM Market Power Mitigation runs on forecasted demand rather than bid-in demand, noting that changing the IFM software to use bid-in demand in Market Power Mitigation could substantially delay implementation of the new market design.

In its September 2006 MRTU Order, FERC granted rehearing to allow the ISO to use forecast demand, rather than bid-in demand, for the pre-IFM Market Power Mitigation process, but directed the ISO to develop systems and tariff language so that bid-in demand can be implemented no later than Release 2.[2] In its April 2007 MRTU Order, FERC also directed the ISO's market monitor to monitor the effects of market power mitigation in the day-ahead using the ISO's load forecasts instead of bid-in demand, including a comparison with an estimate of what the amount of mitigation would have been with bid-in demand, and directed the ISO to include these findings in the ISO's quarterly status reports.[3]

Analysis

DMM has the capability to re-run the IFM using a stand-alone copy of Siemens' market simulation software used in the ISO's new day-ahead market. However, the pre-IFM Market Power Mitigation process incorporated in the stand-alone IFM software cannot be modified by DMM to actually run based on bid-in demand rather than forecasted demand. In order to provide an indication of the level of mitigation that may occur if the software was modified to base Market Power Mitigation on bid-in demand, DMM has developed the capability to modify

[1] September 2005 MRTU Order on Rehearing, 112 FERC ¶ 61,310, at P 69.

[2] September 2006 MRTU Order, 116 FERC ¶ 61,274, at P 1089.

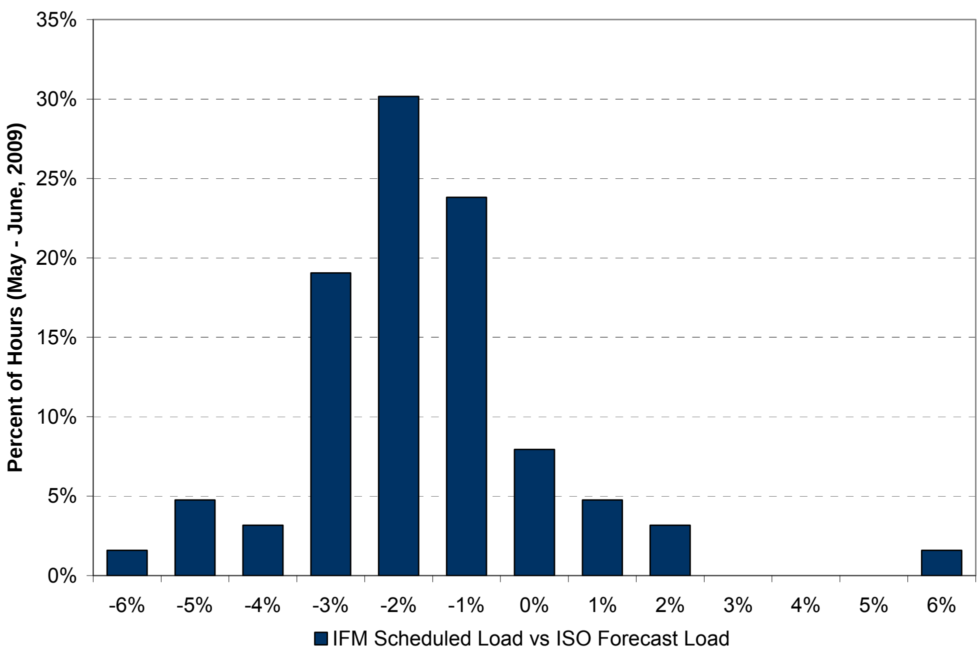
[3] April 2007 MRTU Order, 119 FERC ¶ 61,076, at P 496.

the load forecast used by the software to approximately equal the level of demand that actually cleared the IFM (*i.e.*, actual bid-in demand). Results from this re-run of the IFM can then be compared to actual market results to provide an indication of the impact of basing the pre-IFM Market Power Mitigation process on bid-in rather than forecasted demand.

Since re-running the IFM software in this manner is relatively time intensive, DMM needed to select a limited sample of days for this analysis. Because the primary concern with the use of forecasted demand expressed by the Commission and some stakeholders is that it would result in over-mitigation when demand bid into or clearing the IFM was less than forecasted demand, DMM selected a sample of days that encompass the range of under- or over-scheduling of demand in the IFM (relative to the ISO's forecast) that has occurred over the first three months operations under the new markets.

Figure 1 shows the percentage difference between load scheduled in the IFM and the ISO's day-ahead load forecast for the peak hour of each day during May and June 2009. As shown in Figure 1, the amount of load clearing the IFM has generally been only about one to three percent lower than the ISO's forecast of load. This trend indicates that the use of forecasted rather than bid-in demand is likely to have a very minor impact on the level of mitigation that has occurred due to any under-scheduling in the IFM. Data shown in Figure 1 were also utilized by DMM to select a sample of four different days for more detailed analysis using the DMM's stand-alone IFM software, as described below.

Figure 1 Differences between Load Scheduled in IFM and ISO Forecast Daily Peak Hour, May – June 2009



Results for the four sample days analyzed for this report are summarized in Table 1. Attachment A to this report provides a description of the metrics used to quantify the actual degree and impact of bid mitigation in terms of overall market prices and additional energy dispatched from mitigated units as a result of this mitigation. As shown in Table 1, these results further indicate that use of bid-in rather than forecast demand in the pre-IFM Market Power Mitigation procedures would be expected to have a very negligible impact on the level of mitigation in the IFM, and on final IFM schedules and prices. For example:

- On the two sample days with typical levels of under-scheduling in the IFM relative to the ISO's load forecast (2 percent on June 12 and 26), the analysis showed that use of bid-in demand had a negligible impact on the degree of mitigation in the IFM. On these days, case study results show that use of bid-in demand instead of the forecast would have no effect during the peak hour on final IFM schedules of units with any portion of their bid curves lowered due to mitigation.[4] Moreover, on these two sample days, average prices in the IFM actually decreased by about one percent under the scenario used to estimate the impacts of basing Market Power Mitigation on bid-in demand. Such results are counterintuitive, because basing Market Power Mitigation on a lower level of demand would be expected to decrease mitigation and decrease the pool of resources considered in the IFM.[5] Such counterintuitive results simply reflect the "margin of error" that is involved in trying to assess the impact of a very small change in IFM market inputs, such as a small change in bid prices due to mitigation.[6]
- On the sample day with the highest level of under-scheduling in the IFM relative to the ISO's load forecast (5 percent on June 18), the analysis showed that use of bid-in demand may have decreased the number of units having a portion of their bid curve mitigated (lowered) during the peak hour (would be reduced from four units to one unit). Again, however, such counterintuitive results simply reflect the "margin of error" that is involved in trying to assess the impact of a very small change in IFM market inputs, such as a small change in bid prices due to mitigation.
- On the one sample day with significant over-scheduling (5 percent on June 21), the analysis showed that use of bid-in demand would have a slight increase on the level of mitigation in the IFM, with prices decreasing by about 6 percent. However, analysis of results for this day indicates that this decrease in price is not attributable to bid price mitigation, and is instead

[4] See the final right-most column in Table 1, labeled "Impact of Mitigation during Peak Hour, MW (Q_{IFM} - Q_U)". For a description of these metrics, see Attachment A to this report.

[5] Under current market rules, the pool of bids considered in the IFM is limited to resources that are dispatched in the All Constraints run of the pre-IFM MPM (ISO Tariff Section 31.2).

[6] Such counterintuitive results can be attributed to the fact that relatively small changes in resources and bids considered in the IFM 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. The MIP gap (or Mixed Integer Programming gap) is a measure of the optimality of a solution relative to a theoretical optimal result that could be achieved without integer constraints. The MIP gap is measured in two ways. The absolute MIP gap is calculated based on the difference in the objective function value of a given solution (*i.e.*, total bids costs of resources dispatched to meet load) and the minimal value of the objective function that could be achieved without integer constraints. The MIP gap is also measured on a percentage basis (*i.e.*, the absolute MIP gaps as a percentage of the minimal value of the objective function that could be achieved without integer constraints).

due to the fact that the pool of units considered in the IFM is greater under this scenario, because additional resources are dispatched in the pre-IFM All Constraints run.[7]

Table 1 Analysis of Mitigation Based on Forecast Rather than Bid-in Demand

	Daily Avg Cost	Units with Bids Lowered due to Mitigation: Total Unit/Hours Mitigated	Units with Bids Lowered due to Mitigation: Units Mitigated in Peak Hour	Units with Bids Lowered due to Mitigation: Bids Subject to Mitigation in Peak Hour ($Q_{MAX} - Q_{CC}$) *	Impact of Mitigation during Peak Hour: Units with Higher Dispatch	Impact of Mitigation during Peak Hour: MW ($Q_{IFM} - Q_U$)*
5% Underscheduling / Peak Forecast = 36,970 MW (June 18)						
Base	$28.25	41	4	173	1	37
MPM w/IFM MW	$28.34	32	1	105	1	105
Change	**0%**	**-10**	**-3**	**-68**	**0**	**68**
2% Underscheduling / Peak Forecast = 29,316 MW (June 12)						
Base	$24.56	12	1	270	0	0
MPM w/IFM MW	$24.27	7	0	0	0	0
Change	**-1%**	**-5**	**-1**	**-270**	0	0
2% Underscheduling / Peak Forecast = 35,040 MW (June 26)						
Base	$30.35	9	0	0	0	0
MPM w/IFM MW	$30.15	10	0	0	0	0
Change	**-1%**	**1**	**0**	**0**	**0**	**0**
5% Overscheduling / Peak Forecast = 26,961 MW (June 21)						
Base	$30.58	5	1	281	1	150
MPM w/IFM MW	$28.75	7	3	391	1	112
Change	**-6%**	**2**	**2**	**110**	**0**	**-38**

* For a detailed description of how these metrics are calculated, see Attachment A of this report.

[7] DMM is currently monitoring the impact of the rule limiting bids considered in the IFM to bids that are dispatched in the All Constraints run, rather than all resources. However, DMM has found that to date modifying this rule would have negligible impact on IFM results due to the very limited degree of over- or under-scheduling that has occurred. See *Initial Recommendation on Potential Changes in Market Design Rule Limiting the Pool of Resources Considered in Integrated Forward Market*, Department of Market Monitoring, July 2, 2009. This document is available on the ISO's website at: http://www.caiso.com/23df/23dfb81a48990.pdf.

Use of Forecasted versus Bid-in Load in the pre-IFM LMPM

Background

The Local Market Power Mitigation provisions incorporated in the ISO's new market design provide the option for a bid adder to be included in cost-based Default Energy Bids for resources that are frequently mitigated. Resources that are mitigated in greater than 80 percent of the hours in which they are running are deemed to be Frequently Mitigated Units (FMUs).

The purpose of the FMU bid adder is to provide the opportunity for supplemental revenue for recovery of going-forward fixed costs by those resources that are frequently mitigated to their cost-based levels, which may be at or near their marginal cost of production. Since resources with Reliability Must-Run (RMR) agreements or full capacity Resource Adequacy (RA) contracts receive revenues for recovery of going-forward fixed costs, these units are not eligible for the FMU bid adder. Units with a portion of their capacity under RA contracts are eligible for a portion of the bid adder based on the proportion of the units' capacity that is not covered under an RA contract.

The default FMU bid adder is $24/MWh. For units that have some but not all of their capacity contracted under the RA program, the FMU adder is adjusted pro-rata in proportion to the un-contracted capacity.[8] The bid adder, if elected by the FMU, can only be added to the units' cost-based Default Energy Bids. A negotiated option is available also for resources that believe the default FMU bid adder of $24/MWh is not sufficient in the context of recovering their going-forward fixed cost. [9]

In its June 2007 MRTU Order on Compliance Filings, the Commission indicated that:

> We find the CAISO's decision not to modify the FMU adder at this time has merit. . . . We, however, encourage the CAISO to monitor, among other things, the mitigation frequency of non-RMR and non-RA resources, the number of units that exceed the 80 percent threshold, whether units have an incentive to change their bidding strategy to become eligible for the Bid Adder, and cost recovery opportunities for units mitigated less frequently. We believe that the collection of this information will prove beneficial to the CAISO if the single bid adder does not perform as expected. We also note that the CAISO should monitor the effects of local capacity area RA resource requirements once phased into MRTU to assess whether units needed for local reliability are receiving adequate compensation from RA requirements. We therefore direct the CAISO to report its findings to the Commission in its quarterly reports. The DMM should monitor the mitigation frequency and the RA capacity markets to determine if these markets are sufficiently granular to provide adequate compensation for local reliability units in order to phase out the FMU option. If not, the Commission will revisit this issue and evaluate whether the FMU option should be modified to reflect broader compensation levels for units mitigated less than 80 of its run hours.[10]

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[8] For example, a FMU with 90 percent of its capacity under a RA contract would be eligible for a $2.40 default bid adder.

[9] ISO Tariff Section 39.8.

[10] June 2007 MRTU Order on Compliance Filings, 119 FERC ¶ 61,313, at P 352.

Analysis

Calculating the Bid Adder Eligibility Criteria

Eligibility for the FMU bid adder is established on a monthly basis according to standard criteria. The Scheduling Coordinator submitting bids for generating units is eligible to have a bid adder applied to a generating unit for the next operating month if the criteria in Section 39.8.1 of the ISO Tariff are met.

During the first twelve months after the go-live date of the ISO's new market (April 1, 2009), the *mitigation frequency* used to determined eligibility for the FMU adder will be based on a rolling twelve-month combination of data from the ISO's prior market design and the new market design.

- During the period prior to April 1, 2009, RMR and Out-of-Sequence dispatches, which were used to manage the local congestion, serve as a proxy for being subject to Local Market Power Mitigation. The generating units' dispatched hours are counted as mitigated hours in their mitigation frequency. Run hours are those hours during which a generating unit has positive metered output.

- For the period after April 1, 2009, the mitigation frequency will be based entirely on a generating unit being subject to mitigation under the Market Power Mitigation-Reliability Requirement Determination procedures in Sections 31 and 33 of the ISO Tariff. If a unit is subject to mitigation in either the IFM or Real-Time Market during any hour, that hour is counted as a mitigated hour in their mitigation frequency. It is important to note that, for purposes of this FMU calculation, a unit is considered to be *mitigated* if its dispatch in the All Constraints run of the market software is greater than the unit's dispatch in the Competitive Constraints run of the market software. In practice, as discussed in DMM's *Quarterly Report on Market Issues and Performance* for the period covered in this report, during peak hours when mitigation is highest, only about 70 percent of units subject to mitigation actually have a portion of their bids *lowered* due to mitigation.[11]

Frequently Mitigated Units in Q2 2009

Every month, DMM provides Potomac Economics, an independent entity contracted by the ISO to calculate Default Energy Bids, with a list of generating units which have been mitigated in at least 80 percent of their run hours during the last twelve months prior to the next operating month. Potomac Economics uses this information to determine if these generating units are eligible for a $24/MWh adder to their cost-based Default Energy Bids.

Figure 2 shows the monthly count of FMUs categorized by unit type: RMR, RA, partial RA, and non-RMR/RA units. During each month of the second quarter (Q2) of 2009, a total of seven units have been mitigated in at least 80 percent of their run hours during the prior twelve month period. In both the months of April and May:

- Five of the seven units that met the mitigation frequency criteria were either under RMR or had all of their capacity under RA contract and thus were not eligible for the FMU bid adder.

[11] See *Quarterly Report on Market Issues and Performance*, July 30, 2009, prepared by Department of Market Monitoring, pp28-32 (available on CAISO website)

- The remaining two resources were relatively small (~50 MW) units with over 96 percent of their capacity contracted under the RA program, so that they were eligible for a very small portion of the $24/MWh default adder (~4 percent).

In June, four resources were eligible for the bid adder:

- As in April and May, the two partial-RA resources were eligible for FMU status in June. These were relatively small units with over 97 percent of their capacity contracted under the RA program, so that they were eligible for a very small portion of the $24/MWh default adder.
- Two non-RA units became eligible for FMU status in June. These were relatively small units, which had been under RA contracts in previous months, but were ineligible for RA status in June due to outages for maintenance scheduled to occur in June. The mitigation frequency of these two units during the first two months of the ISO's new market design (April and May) was actually extremely low (< 1 percent of hours). This indicates that these units had a much higher level of mitigation frequency in the twelve months prior to the start of the ISO's new markets, and that their mitigation frequency has actually dropped substantially during the first few months of the ISO's new market design.

In future months, the amount of capacity eligible for the FMU adder will be increasingly determined based on the frequency of mitigation resulting from the ISO's new Local Market Power Mitigation procedures. As previously noted, the overall frequency of mitigation has been relatively limited during the second quarter of 2009.

This trend is further illustrated in Table 2, which shows the total run hours and frequency of mitigation of the only non-RA thermal generating units within the ISO system during the April to June 2009 period that were subject to bid mitigation.[12] As shown in Figure 2, while several combined cycle units were not under RA or RMR contract during any portion of the second quarter, these units had relatively high run hours and were subject to mitigation during only a small portion of these hours (3-5 percent of hours). Meanwhile, the only two combustion turbines that were not under RA or RMR contract during any portion of the second quarter had much lower run hours, but were only mitigated during one or two hours each. These units are owned by LSEs and are not within any of the major Local Capacity Areas (LCAs), but were not listed under their RA showings during any portion of the second quarter of 2009.

[12] A significant number of units are partial RA units, since their Net Qualifying Capacity (which reflects potential unit outages, energy limitations and ambient derates) that is eligible for RA status is slightly below their maximum rated capacity. In other cases, units may not be under RA designation for one month due to a scheduled outage that prevents the unit from being used to meet an LSE's RA obligation that month.

Figure 2 Number of Resources, by Contract Status, That Exceeded Mitigation Frequency for Prior 12 Months

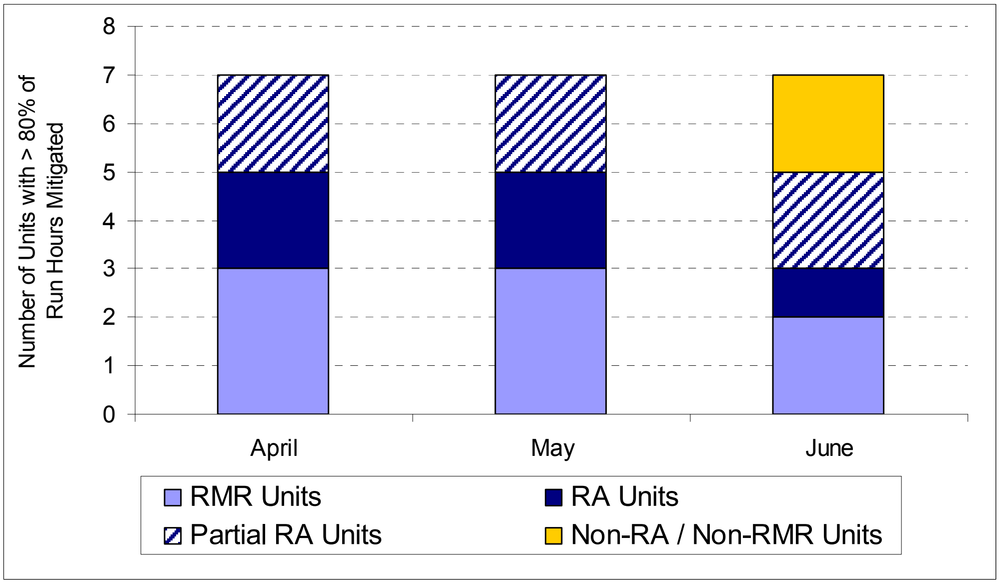


Table 2 Mitigation Frequency of Non-RA/RMR Resources in Q2 2009

Unit Type	Total Run Hours	Run Hours as Percent of Total Hours	Hours Subject to Bid Mitigation	Percent of Run Hours Subject to Mitigation
Combined Cycle	1,446	66%	67	5%
Combined Cycle	1,300	60%	57	4%
Combined Cycle	1,794	82%	51	3%
Combined Cycle	690	32%	17	3%
Combustion Turbine	198	9%	2	1%
Combustion Turbine	301	14%	1	0%

Attachment A: Metrics Used to Assess Impacts of Bid Mitigation in IFM

The analysis of the impacts of the use of forecasted versus bid-in load in the pre-IFM Local Market Power Mitigation procedures provided in the first section of this report includes several metrics used to quantify the actual degree and impact of bid mitigation occurring under different market scenarios (see Table 1 of this report). This Attachment A provides a more detailed description of these metrics and how they were calculated.

Figure A.1 illustrates how the Local Market Power Mitigation procedures are applied to a unit's IFM bid curve under the ISO's new market design. Prior to the IFM, the ISO's software is first run with only Competitive Constraints enforced. The Competitive Constraints run is performed by clearing unmitigated market bids with the ISO's day-ahead forecast of demand. A second run is then performed with All Constraints enforced. Units which are dispatched at a higher level in this All Constraints run than in the first Competitive Constraints run are subject to bid mitigation. As illustrated in Figure A.2, the unit's initial market bid is subject to mitigation since its dispatch in this second All Constraints run (Q_{AC}) is greater than its dispatch in the first Competitive Constraints run (Q_{CC}). The unit's highest market bid dispatched in the Competitive Constraints run is used as a *floor* below which the unit's bid is not mitigated, even if this exceeds the unit's Default Energy Bid (*e.g.*, see the unit's final mitigated bid for capacity up to Q_{CC} in Figure A.2). The unit's bid curve is only mitigated (*i.e.*, lowered) to the extent that its market bid exceeds the maximum of this bid floor or the unit's Default Energy Bid for energy above the unit's dispatch level in the Competitive Constraints run. This final mitigated bid is then used in the IFM. A similar Local Market Power Mitigation process is performed prior to the real time market during the Hour-Ahead Scheduling Process.

Figure A.1 and Figure A.2 also illustrate several different metrics developed by DMM to assess the degree of bid mitigation occurring under these Local Market Power Mitigation procedures.

- **Units With Market Bids Lowered Due to Mitigation.** As shown in Figure A.1, the total quantity of a unit's initial unmitigated market bid that can potentially be lowered as a result of Local Market Power Mitigation procedures extends from the unit's highest bid dispatched in the Competitive Constraints run (Q_{CC}) up to the unit's maximum bid capacity (Q_{Max}). However, in a substantial number of cases, bids for units subject to mitigation may not actually be lowered. One reason this can occur is that the highest-priced unmitigated bid dispatched in the Competitive Constraints run (P_{CC}) is used as a *floor* below which other market bids are not lowered. In addition, this can occur since units may bid at or below their Default Energy Bids.

- **Bids from Mitigated Units Dispatched in IFM.** As shown in Figure A.1, even if a unit has the bid price for a portion of its initial market bid curve *lowered* due to mitigation, only a portion of these bids may be dispatched in the IFM. Thus, a second measure of the degree to which mitigated bids may be dispatched in the IFM is to calculate the incremental amount that each unit having its bid curve lowered through Local Market Power Mitigation procedures is actually dispatched in the IFM. As illustrated in Figure A.1, this quantity is calculated based on the difference between each unit's dispatch in the Competitive Constraints run (Q_{CC}) and its actual IFM schedule (Q_{IFM}).

- **Increase in Dispatch due to Mitigation.** Finally, as shown in Figure A.2, the actual increase in a unit's dispatch due to bid mitigation can be assessed even more precisely by estimating the portion of the unit's capacity that would have cleared the IFM if its bid had not been mitigated. In Figure A.2, it is assumed that the unit's dispatch in the IFM (Q_{IFM}) is greater than its dispatch in the Competitive Constraints and All Constraints runs due to the fact that its final mitigated bid used in the IFM is lower than its initial market bid. The increase in the unit's IFM schedule due to mitigation can be approximated by calculating the portion of the unit's initial unmitigated bid curve with a bid price equal to or lower than the clearing price in the IFM (Q_U). The difference between this level (Q_U) and its actual IFM schedule (Q_{IFM}) provides an indication of the magnitude of the actual impact of bid mitigation given actual IFM prices and the degree to which the unit's initial market bid was actually mitigated (lowered).[13]

[13] In practice, the unit's bid price at its actual dispatch level in the IFM (Q_{IFM}) can be lower than the unit's bid price due to the fact that the IFM is a 24-hour optimization. This could also create situations where the amount of the unit's unmitigated bid curve below the IFM price was less than the unit's dispatch in the Competitive Constraints run. To avoid any overestimation of the impacts of mitigation that could result from these conditions, the estimated dispatch of the unit with unmitigated bids was constrained to be not less than its dispatch in the Competitive Constraints run ($Q_U \geq Q_{CC}$). The net effect of this constraint is simply to prevent the measure of the increase in dispatch due to mitigation during any hour (Q_{IFM} - Q_U) from exceeding the actual increase in the unit's final IFM schedule over the unit's dispatch in the Competitive Constraints run based on its unmitigated bids (Q_{IFM} - Q_{CC}).

Figure A.1 Bid Mitigation

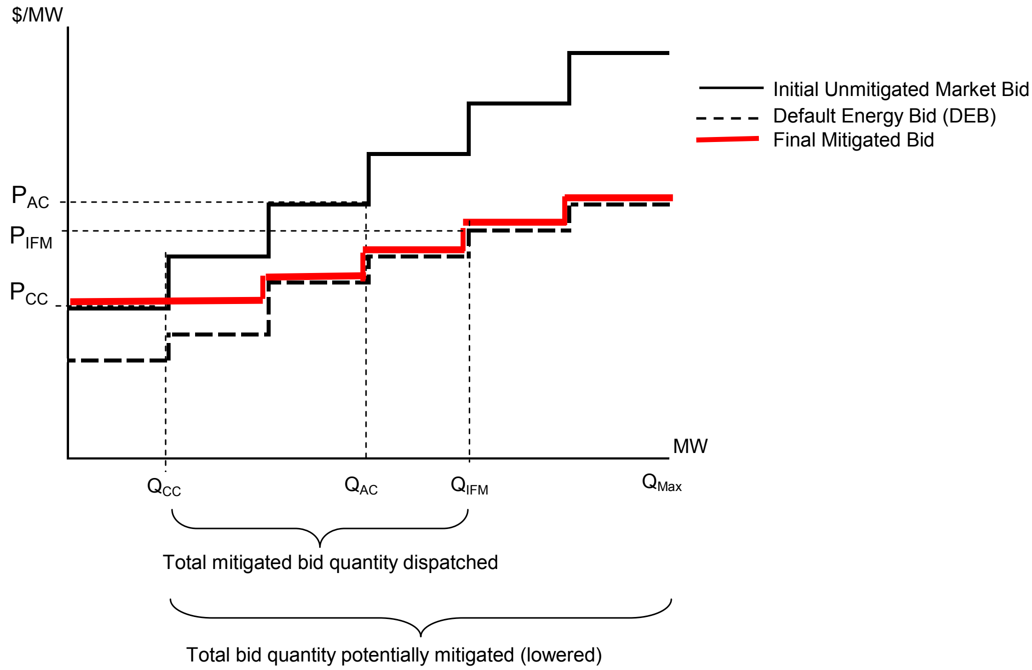
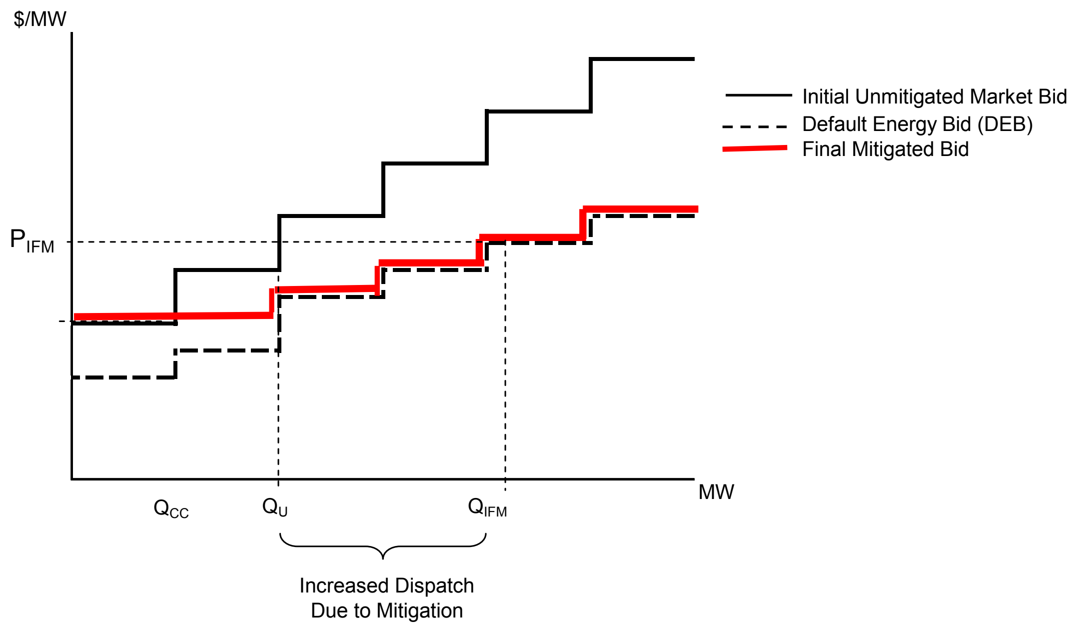


Figure A.2 Measuring Impact of Bid Mitigation



CERTIFICATE OF SERVICE

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

Dated at Folsom, California this 30th day of July, 2009.

/s/ Anna Pascuzzo

Anna Pascuzzo