California ISO
Your Link to Power

California Independent
System Operator Corporation

October 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 third quarter of 2009 (from July 1, 2009, through September 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 from July 1 through September 30 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 other Commission directives on quarterly reporting issued in the September 2006 Order, subsequent Commission orders as noted, and ISO requirements and commitments.

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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").

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 July 1-September 30 time period. These matters include the following:

- Market 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 both Day-Ahead and Real-Time Markets, 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 July 1-Spetember 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.

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

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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).

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 both the Day-Ahead and Real-Time Markets 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.

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 ISO Board.

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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).

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.

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 ISO's Department of Market Monitoring (DMM) has performed analysis of the competitiveness of various constraints under actual market conditions over the first five months of the ISO's new nodal market design using a methodology based on the Residual Supply Index (RSI) or Pivotal Supply Test.[18] This analysis was designed to provide a basis for comparing results of the Competitive Path Assessment methodology with results derived under other approaches similar to those used by other ISOs. DMM believes that these results may be useful as the MSC considers its review of the Competitive Path Assessment methodology that the Commission has directed the MSC to perform. DMM presented its analysis and results, and discussed issues relating to the Competitive Path

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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.

18 *Residual Supply Metrics: Preliminary Methodology and Results*, Draft Whitepaper Prepared for October 15, 2009 MSC Meeting, Department of Market Monitoring, October 13, 2009, http://www.caiso.com/2447/24478feb48570.pdf.

Assessment methodology at the October 15, 2009 MSC meeting.[19] DMM stands ready to provide any other analysis or data the MSC may find useful in its assessment of the Competitive Path Assessment methodology.

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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[19] *Residual Supply Metrics for Transmission Congestions*, presentation by Dan Yang, Ph.D., Department of Market Monitoring, Prepared for Market Surveillance Committee Meeting, October 15, 2009, http://www.caiso.com/2447/2447affd55010.pdf. *See also*, Memorandum dated October 21, 2009 from the MSC to the ISO Board of Governors regarding Market Surveillance Committee Activities from August 19, 2009 to October 14, 2009, http://www.caiso.com/244f/244f99ce5fab0.pdf

Attachment A
Market Services Quarterly Report

California Independent
System Operator Corporation

California ISO

Post Implementation Report

October 30 2009

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Introduction

This report is prepared under the direction of the Market Services branch, which is part of the Operations division of the California Independent System Operator (ISO). Contemporaneously with this report, the ISO's Department of Market Monitoring will be submitting a report that addresses its specific responsibilities. Paragraph 1417 of the September 21, 2006 order[1] issued by the Federal Energy Regulatory Commission (FERC) directed the ISO to, "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 directive, FERC subsequently issued a number of additional reporting directives, which are referenced via footnotes at the start of each section in this report.

[1] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006) ("*September 2006 MRTU Order*").

Market Performance[2]

Market Characteristics

Loads

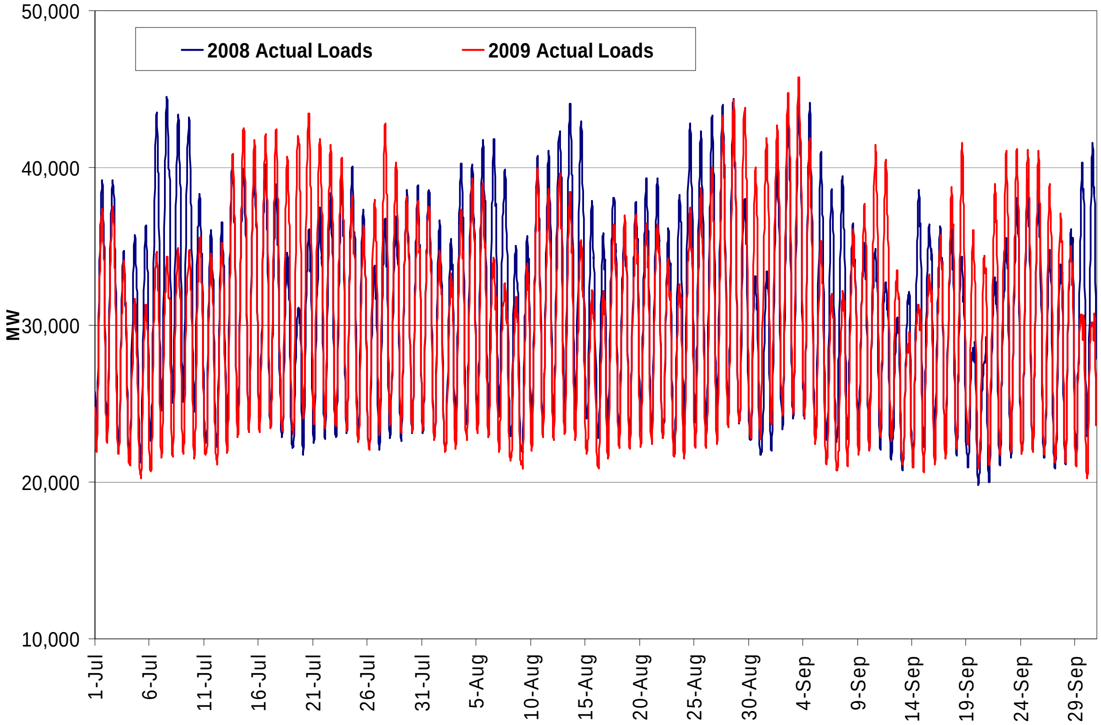
For the reporting period July 1st through September 30th, daily load levels were below the level of the previous year due to relatively mild weather and a slow economy. During July and August summer temperatures were mild. Load was moderate, which occasionally drifted over 40,000 MW, mostly in the middle of July and the last week of August when temperatures were high. The summer-like weather continued into September, as load went over 40,000 MW on 11 out of 30 days of the month, peaking at 45,762 MW as shown in Figure 1.

[2] This section of the report is based on paragraph 1417 of the September 21, 2006 FERC Order, in which FERC directed the ISO to file reports and provide an opportunity for market participants to contribute to the nature of the reports. Consistent with this requirement, the ISO held a series of stakeholder meetings starting in late 2007, during which it proposed a preliminary set of market metrics to be filed with FERC every quarter. This proposed report would contain numerous metrics which would highlight the performance of various markets operated by the ISO. Prior to the stakeholder meeting, the ISO published a template document on its website, which contained a set of metrics that the ISO intended to use to monitor the market performance. The stakeholders were generally supportive of this approach and had some suggestions. While the ISO has fulfilled the vast majority of these requests there are a few that are still under development. The metrics requested through this process 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.
4. The effect of market application failure on market outcomes.
5. Accuracy of the ISO Day-Ahead and Real-Time load forecast compared to the actual load.
6. The Locational Marginal Prices (LMPs) and aggregated prices of Metered Subsystems (MSS).
7. The exceptional dispatch of Resource Adequacy (RA) units in Day-Ahead and Real-Time Markets.
8. The RUC procurement target and RUC procured quantities.
9. The Ancillary Service requirements and costs.

In this FERC Quarterly Implementation Report for the third quarter of 2009, the ISO has included metrics in item numbers 2, 7, 8 and 9 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 4 and 7 shown above. The ISO will continue to develop metrics which will include all the remaining items mentioned above (1, 3, 5, & 6) and incorporate those in the future FERC quarterly implementation reports. Further, in the light of experience the ISO 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.

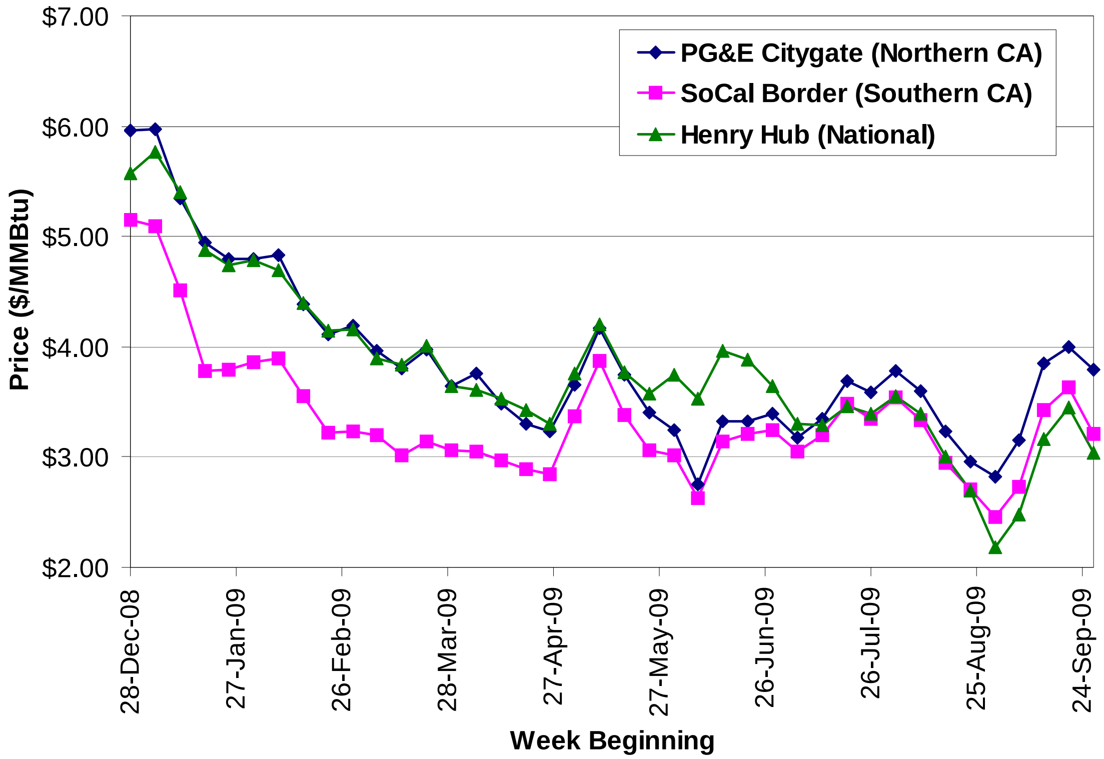
Figure 1: System Load Comparison –2009 vs. 2008



Natural Gas Prices and Inventories

Natural gas prices fluctuated between $2 /MMBTU and $4 /MMBTU from July 1st through September 30th. Natural gas prices trended upward slightly in July driven by increased demand due to higher temperatures, and then significantly declined in August driven by robust supplies. Prices increased again during September. The California Composite Average gas price increased to $3.76 per MMBtu on September 30th from $3.29 per MMBtu on July 1st.

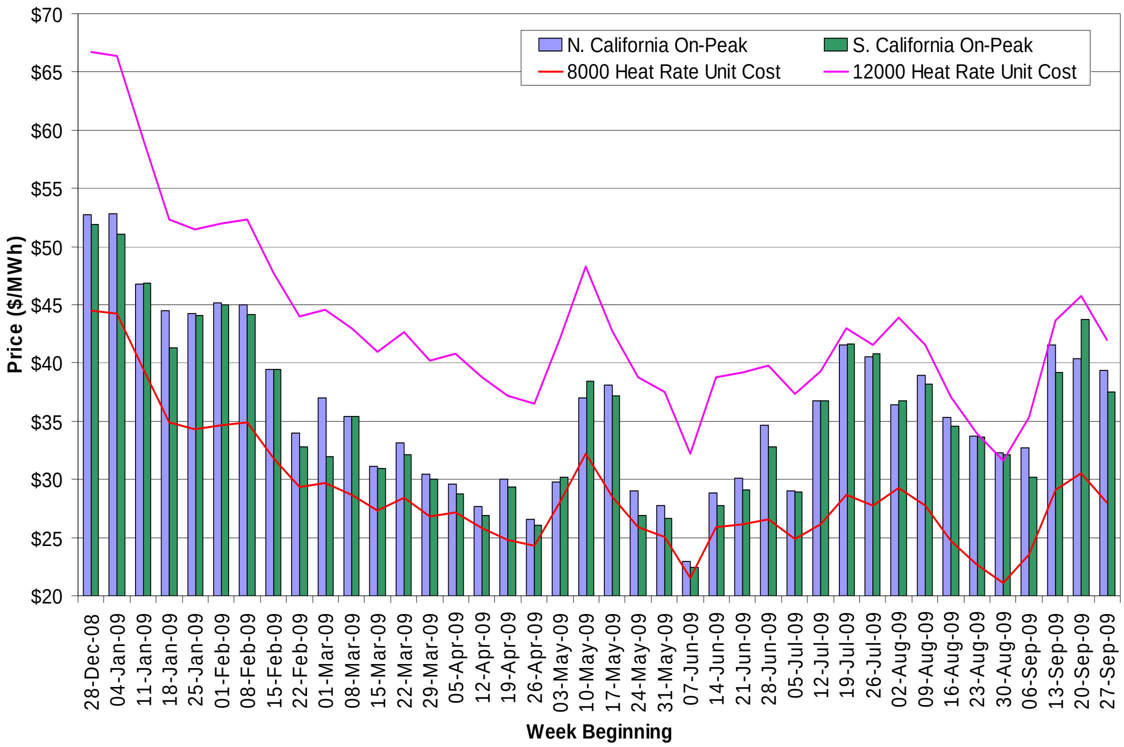
Figure 2: Weekly Average Natural Gas Spot Prices January 2008 to September 2009



Bilateral Electricity Prices

Day-ahead, on-peak power prices climbed in July and fell significantly in August, and then climbed again in September following the trend in 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



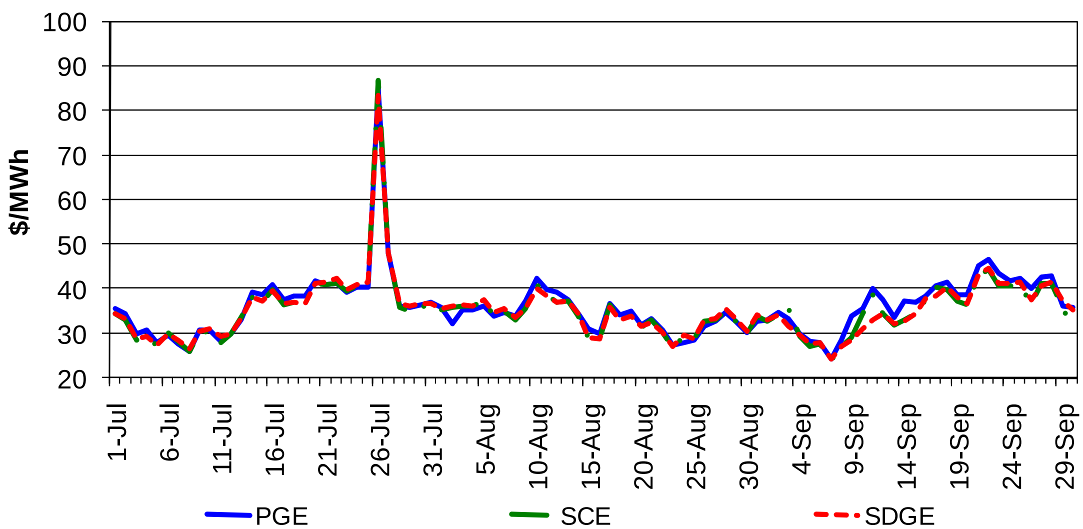
Market Performance Metrics

Energy

Day-Ahead Prices

Figure 4 shows the daily day-ahead Load Aggregation Point (LAP) prices for the third quarter of 2009. Day-ahead daily average prices on almost all days of the quarter were fairly stable, falling into the range of $24/MWh to $49/MWh. The exception was July 26th, when LAP prices spiked above $420/MWh for two hours due to a limited availability of resources in the Integrated Forward Market (IFM). This limitation was due to a specific design feature of the Day-Ahead Market (DAM). Prior to the IFM, the Market Power Mitigation (MPM) run clears forecast ISO demand against all bid-in generation, and then generates a mitigated bid set. This mitigated bid set contains only those units which were used to meet the day-ahead load forecast and only the bids from these particular units are considered by the IFM. On July 26th in hours ending 17 and 18, the cleared demand in IFM was significantly above the day-ahead load forecast used in the MPM run, and this required the IFM to clear higher priced resources in the mitigated bid-set to meet this demand. Due to these unusual circumstances, prices were higher than they might otherwise have been because some resources that bid into the DAM were excluded from the mitigated bid set in the IFM since they were not picked up in the preceding MPM run. Prices in the three default LAPs for the quarter diverged on several days in August and September due to congestion on some transmission facilities. Consistent with the movement of the natural gas prices, the DAM saw increasing trends in energy prices during July and September, and a decreasing trend in August.

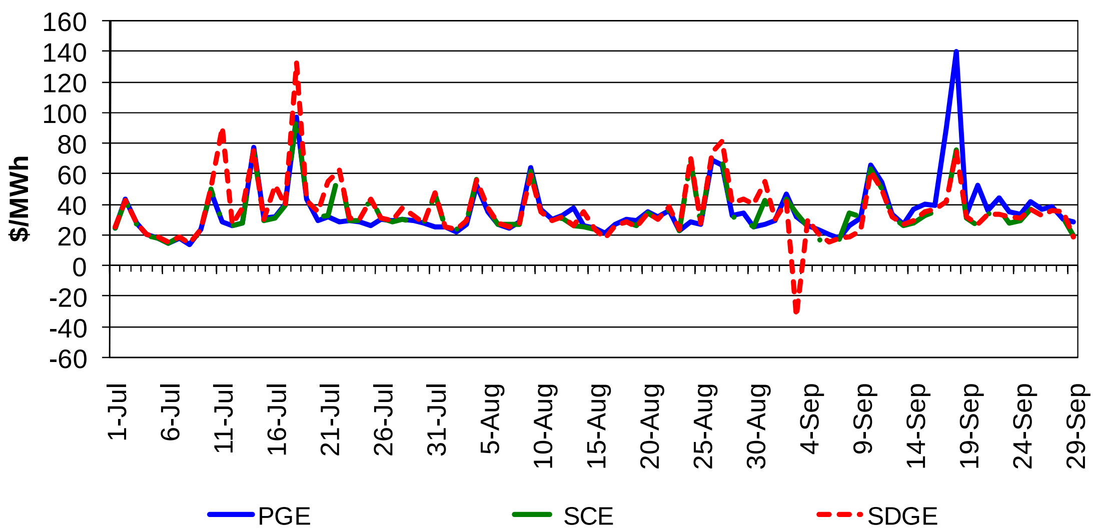
Figure 4: Day-Ahead Weighted Average LAP Prices (All Hours)



Real-Time Prices

The daily real-time energy prices are shown in Figure 5 for three default LAPs for the third quarter of 2009. Price volatility appeared in every month of the quarter. In July and August, prices were more variable in the SCE and SDG&E areas, while in September, prices were more volatile in the PG&E area. The divergence of the prices among three default LAPs was mostly driven by congestion on different transmission facilities. The real-time energy prices were generally moderate for the quarter, with exceptions on two days in July and three days in September. On July 11th, prices in the SDG&E area were elevated by congestion on the SDGE_CFE and SDGE import branch groups, which were de-rated due to a scheduled outage of the Otay Mesa - Tijuana 230 kV line. On July 18th, the peak load pull and limited ramp capability, plus a loss of 325 MW due to trip of a generation unit, resulted in elevated prices in all default LAPs with daily average prices above $97/MWh. On September 3rd, prices in the SDG&E area were depressed by congestion on a nomogram, where this nomogram was created to account for a scheduled outage of the San Onofre - Santiago # 2 230 kV line. On September 17th and 18th, congestion on the Los Banos North branch group elevated prices in the PG&E area. On all the other days in the quarter, the daily average real-time energy prices for three default LAPs fell between $14/MWh and $82/MWh.

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

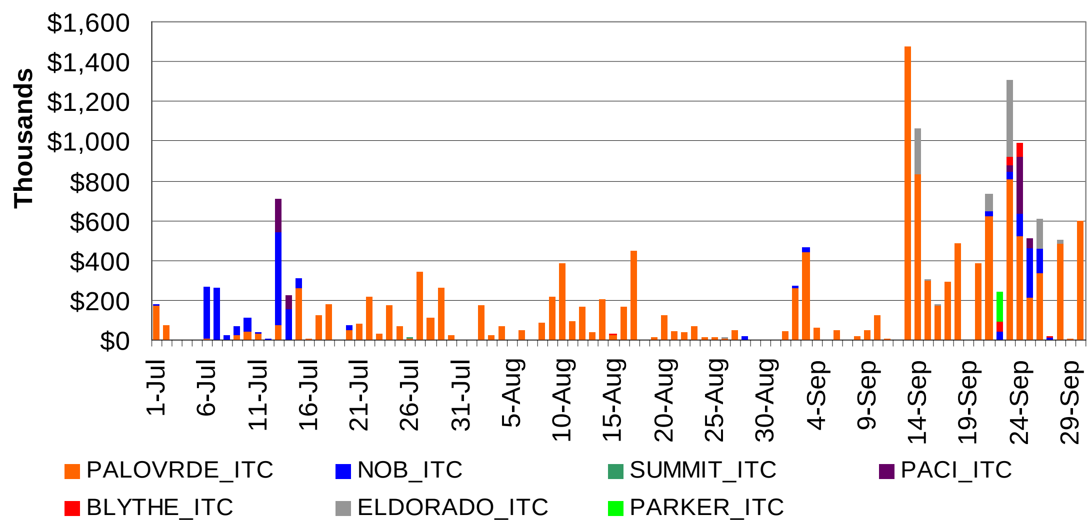


Congestion

Congestion Rents on Interties

Figure 6 below illustrates the daily total IFM congestion rents by inter-tie for the third quarter of 2009, while Table 1 provides a breakout of the IFM cleared volumes (MW), average shadow price ($/MWh) and number of congested hours by intertie. The cumulative congestion rents at inter-ties for the third quarter of 2009 were $17.4 million. The ISO calculates congestion rents at each intertie as the shadow price multiplied by the flow limit at the intertie. Of the total, the vast majority of rents occurred on three interties: Palo Verde (77.9 percent), NOB (11.7 percent) and EL DORADO (5 percent).

Figure 6: IFM Congestion Rents by Intertie (Import)



The Palo Verde intertie was congested on most days during the second half of July, and this congestion was primarily driven by over scheduling. The majority of the congestion rents on the NOB branch group were occurred during the first half of July at a monthly average shadow price of $9/MWh. During this timeframe, congestion was driven by price differential between the Pacific Northwest Trading Hub prices and the California Trading Hub prices. In the second half of July, loads picked up significantly in the Pacific Northwest due to an increase in temperatures and congestion on NOB reduced significantly.

Congestion rents on inter-ties during the month of August were primarily driven by over scheduling when scheduling coordinators were importing cheap energy from the neighboring states and the total bid-in schedules exceeded the available capacity.

Congestion rents climbed in September, with congestion on Palo Verde intertie being the main contributor. Starting on September 11th, the Palo Verde inter-tie was sharply derated to over 50 percent of its nominal capacity due to a forced outage on the Hassayampa-North Gila 500 kV line. For a couple of weeks, the capacity on Palo Verde inter-tie fluctuated between 1505 MW and 1000 MW due to several outages including this forced outage. Although the Hassayampa - North Gila line was back in service on September 24th, derates on the Palo Verde inter-tie continued in certain hours from September 25th through September 30th due to a combination of other planned and forced outages.

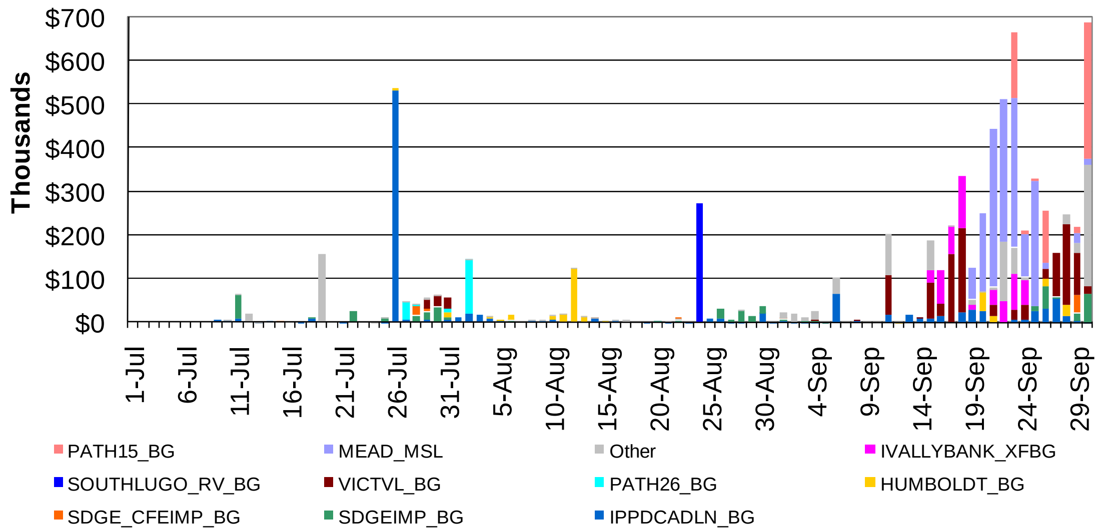
Table 1: IFM Congestion Statistics by Inter-Tie (Import)

Inter-Tie	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
NOB_ITC	Jul-09	1,524.71	12.84	72
PACI_ITC	Jul-09	2,731.75	10.84	8
PALOVRDE_ITC	Jul-09	2,813.35	5.31	164
SUMMIT_ITC	Jul-09	1.67	82.02	18
BLYTHE_ITC	Aug-09	211.67	2.63	3
ELDORADO_ITC	Aug-09	1,555.00	0.75	1
NOB_ITC	Aug-09	318.20	14.32	10
PALOVRDE_ITC	Aug-09	2,817.18	3.77	242
BLYTHE_ITC	Sep-09	159.86	30.10	70
ELDORADO_ITC	Sep-09	1,252.04	12.51	56
NOB_ITC	Sep-09	1,098.88	18.63	33
PACI_ITC	Sep-09	2,492.38	8.81	16
PALOVRDE_ITC	Sep-09	1,485.64	21.14	362
PARKER_ITC	Sep-09	186.13	35.38	23
SUMMIT_ITC	Sep-09	43.00	5.26	13

Congestion Rents on Branch Groups

Figure 7 illustrates IFM daily total congestion rents on branch groups, while Table 2 provides a breakout of the IFM cleared volumes (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 third quarter of 2009, the total branch group congestion rent was approximately $7.4 million. The majority of branch group congestion rents occurred on MEAD_MSL (23.3 percent), Victorville (15.5 percent), and IPPDCADLN (15 percent).

Figure 7: IFM Congestion Rents by Branch Group



Approximately 50 percent of congestion on the IPPDC branch group occurred on July 26 in hours ending 17 and 18. The IPPDC branch group is a radial branch group which connects the Adelanto pricing node to the Inter-Mountain Power Project. During those hours most of the ISO system, including the Adelanto pricing node, saw LMPs greater than $450/MWh, which was driven by an unusual event. As explained above in the section discussing day-ahead prices, day-ahead LAP prices were driven up when bid-in demand was significantly higher than the day-ahead load forecast. The ISO's market software attempted to dispatch all possible generation including imports, which resulted in flows reaching the capacity of the IPPDC branch group. With cheap generation stranded at the other end of IPPDC branch group, significantly high shadow prices resulted.

Table 2: IFM Congestion Statistics by Branch Group

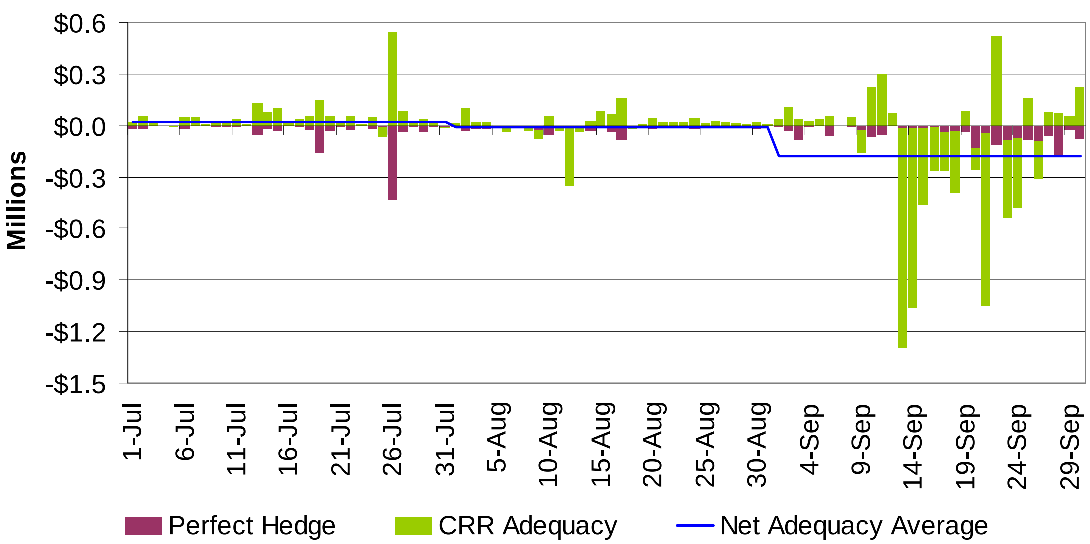
Branch Group	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
HUMBOLDT_BG	Jul-09	43.00	60.75	6
IPP-IPPGEN_MSL	Jul-09	470.00	21.04	16
IPPDCADLN_BG	Jul-09	647.00	17.43	52
LOSBANOSNORTH_BG	Jul-09	1,275.00	17.10	1
MONAIPPDC_MSL	Jul-09	236.00	1.52	8
PATH26_BG	Jul-09	2,700.00	5.09	4
SDGEIMP_BG	Jul-09	2,263.33	3.12	24
SDGE_CFEIMP_BG	Jul-09	2,072.96	1.34	11
VICTVL_BG	Jul-09	2,640.00	5.66	5
WSTWGMEAD_MSL	Jul-09	180.62	2.66	13
HUMBOLDT_BG	Aug-09	44.71	55.67	78
IPPDCADLN_BG	Aug-09	647.00	1.98	113
LUGO_VINCENT_BG	Aug-09	3,150.00	0.61	2
MONAIPPDC_MSL	Aug-09	83.43	4.28	14
PATH26_BG	Aug-09	1,700.00	14.75	5
SDGEIMP_BG	Aug-09	2,647.05	1.60	22
SDGE_CFEIMP_BG	Aug-09	2,083.67	1.42	3
SOUTHLUGO_RV_BG	Aug-09	4,150.00	16.44	4
WSTWGMEAD_MSL	Aug-09	185.32	2.18	41
ADLANTOSP_MSL	Sep-09	1,207.66	5.37	29
HUMBOLDT_BG	Sep-09	45.06	276.12	8
IPPDCADLN_BG	Sep-09	647.00	4.04	142
IVALLYBANK_XFBG	Sep-09	900.00	7.36	79
LOSBANOSNORTH_BG	Sep-09	2,305.25	4.25	20
LUGO_VINCENT_BG	Sep-09	3,000.00	0.48	3
MEAD_MSL	Sep-09	1,460.00	10.43	113
MIGUEL_IMP_BG	Sep-09	1,900.00	8.95	19
MKTPCADLN_MSL	Sep-09	630.00	8.76	5
MONAIPPDC_MSL	Sep-09	236.00	1.18	5
PATH15_BG	Sep-09	3,317.65	5.75	34
SDGEIMP_BG	Sep-09	2,096.42	3.56	25
SDGE_CFEIMP_BG	Sep-09	2,259.64	2.76	7
VICTVL_BG	Sep-09	2,550.00	5.52	76
WSTWGMEAD_MSL	Sep-09	186.00	31.65	16

Two significant transmission outages in September were primarily driving congestion rents on branch groups. First, the Adelanto-Toluca 500kV line was forced out of service starting from September 2nd till September 27th due to station fires. Second, as mentioned in the previous section, the Hassayampa-North Gila 500kV line was forced out of service from September 11th until September 24th. These two outages were primarily driving congestion on Victorville branch group. The forced outage of Hassayampa-North Gila 500kV line was also driving increased congestion at the Imperial Valley transformer branch group. With the Palo Verde intertie derated due to a forced outage, scheduling coordinators may have sought alternative tie points to import power from Northwest into the ISO. Scheduling coordinators increased import bids on the Mead and Victorville scheduling points, which caused the congestion observed in September.

Congestion Revenue Rights[3]

Figure 8 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the third quarter of 2009. A net positive value indicates that there is a surplus and a net negative value indicates there is a shortfall. Revenue adequacy for CRRs reflects the extent to which the hourly net congestion revenues collected from the 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. Because the perfect hedge reduces the net IFM congestion revenues available for paying CRR holders, 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 8: Daily Revenue Adequacy of Congestion Revenue Rights



Both the hourly CRR revenue adequacy amounts (net congestion revenues less net payments to CRR holders, as reflected in the green bars in Figure 8) and the congestion credit for the perfect hedge are aggregated across all hours of each month to obtain the net revenue adequacy. This amount is supplemented by the net CRR auction revenues collected by the ISO for the month through the mechanism of the CRR balancing account. Auction revenues are not incorporated in Figure 8. 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,

[3] The metrics presented in this section and also in the sections of Post-Day-Ahead Perfect Hedge and Cost of the Perfect Hedge are based on preliminary settlements data. For the month of July, the metrics are based on T+38B data, while for the month of August and September the metrics are based on T+7B data.

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 8, 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 8 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. As shown in Figure 8, the daily average of revenue surplus has been $20,602, -$5,967 and -$175,245 for July, August and September, respectively.

In July, the ISO observed deficiencies in six out of 31 days of the month, with the most significant deficiency occurring on July 25th. On this day, the NOB inter-tie was out of service to accommodate the outage of the Celilo-Sylmar 1000 kV line. For August, revenue deficiencies occurred in 11 out of 31 days of the month, with the most significant deficiency occurring on August 12th when the Humboldt branch group was binding throughout the day. The main factor that drove revenue deficiency in September was the major derate on the Palo Verde inter-tie, as explained above in the section of congestion on interties. Revenue deficiencies were observed in 15 out of 30 days of September, with the most significant deficiencies observed between September 13th and September 24th. Such revenue deficiencies occurred because with the derate on Palo Verde, congestion rents were collected on less transmission capacity available in the energy market, in comparison to the transmission capacity used to release CRRs. It is worth noting that outside the period in which Palo Verde was forcedly derated, the market saw a CRR revenue surplus of $0.34 million in September, which may suggest that if the outage had not occurred, September would have seen a revenue surplus.

During the third quarter, the ISO had used two adjustments in 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, and without relying on the CRR auction revenues.

1. 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. 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 mechanism for the ISO to account for significant transmission outages when determining the network capacity available for each monthly CRR release process. For every month of the third quarter, outages with duration of 10 days or less were modeled with pro-rata derates to reflect the portion of the month they were planned to be out of service. For outages with duration of 10 days or longer, the transmission elements were explicitly modeled as out of service.

2. Global derating factor.

Outages that cannot be captured by the 30-day rule, such as unscheduled outages, are not 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 August and September, this derating factor was insufficient to ensure revenue neutrality, though the revenue deficiency for August was much less than for September.

Table 3 provides a summary of the monthly statistics for CRRs for the third 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 offset the revenue deficiencies in the monthly clearing process, the monthly net balance allocated to measured demand was negative only for the month of September. Although auction revenues can be used to offset any CRR revenue deficiency, 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.

Table 3: Summary of Monthly Revenue Adequacy

	JULY	AUGUST	SEPTEMBER
Congestion Rents	$6,751,414.96	$4,555,114.23	$20,452,204.65
CRR Payments	$5,098,354.37	$4,289,136.58	$24,233,273.82
CRR Adequacy	$1,653,060.60	$265,977.65	-$3,781,069.16
Perfect Hedge	-$1,014,383.41	-$450,968.18	-$1,476,300.41
Net Adequacy	$638,677.2	-$184,990.5	-$5,257,369.6
Adequacy Ratio	110.45%	96.10%	79.55%
Auction Revenues	$2,152,730.7	$1,830,817.8	$1,734,380.7
Monthly Net Balance	$2,791,407.9	$1,645,827.2	-$3,522,988.9

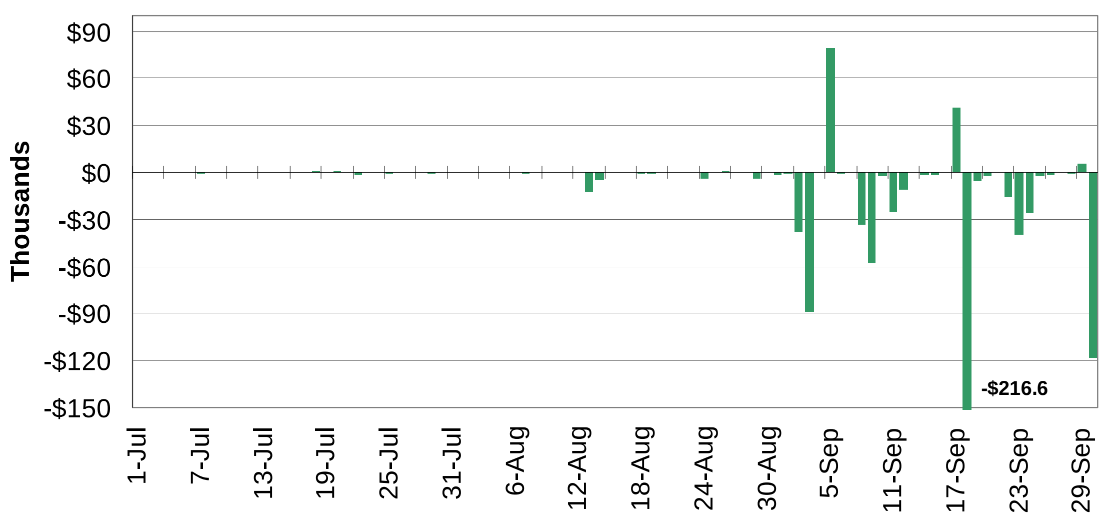
Unlike the month of July in which there was a CRR revenue surplus, auctions revenues were used to offset the revenue deficiencies of August and September. For August, there was still some surplus left in the balancing account (Monthly Net Balance) that the ISO distributed to measured demand. In September, in contrast, there was a net revenue deficiency of $3.5 million that the ISO will allocate to measured demand. Through the quarter, the revenue adequacy ratio declined from 110.4 percent to 79.5 percent, as the surplus of $0.63 million in July turned into a deficiency of $5.2 million in September. Auction revenues have consistently decreased during the July –September time period from $2.7 million to $1.7 million

Post-Day-Ahead Perfect Hedge

Similar to the Day-Ahead Market (DAM), the ISO collects Real-Time Market (RTM) congestion rents determined by the charges to demand and payments to supply for schedule deviations from Day-Ahead Schedules and imports of ancillary services via the interties. Depending on contract provisions, some holders of ETCs/TORs may utilize their rights to submit post-day-ahead, (i.e. in the HASP or real-time frame) schedule changes with respect to their accepted day-ahead self-schedules.[4] As required by the ISO tariff, these schedules are not subject to congestion charges. This provision also applies both in the day-ahead and the real-time, and in the real-time is independent of any settlement of the day-ahead. 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 real-time congestion rents and the perfect hedge costs do not impact the settlements of CRRs, the ISO accounts for these in real time funds through a separate real-time mechanism (i.e., the real-time congestion off-set) instead of the CRR balancing account.

Figure 9 shows the daily net cost for honoring the perfect hedge of post-day-ahead schedule changes of ETC/TOR. A negative value of the perfect hedge indicates a net payment from the ISO to 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 ETC/TOR holders to reverse the post-day-ahead congestion payment.

Figure 9: Cost of the Perfect Hedge for Post-Day-Ahead ETCs/TORs



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

The extent of the cost of the perfect hedge for post-day-ahead schedule changes for ETCs/TORs depends not only on the post-day-ahead congestion but also on the extent of schedule changes submitted by their holders. As shown in Figure 9, the cost of the perfect hedge for post-DA transactions was relatively low in July and August, but increased during September due mainly to higher congestion experienced in the RTM.

Ancillary Service Markets

Integrated Forward Market (Day-Ahead) Average Prices

Table 4 shows the daily IFM (day-ahead) average ancillary service procurements and prices for the third quarter of 2009, and Figure 10 on the next page shows the daily IFM average prices. The daily average price for each type of ancillary service is calculated as the average of the hourly price for all trading hours, where the hourly price is equal to the total cost of procuring non-self scheduled ancillary service divided by the total non-self scheduled procurement.

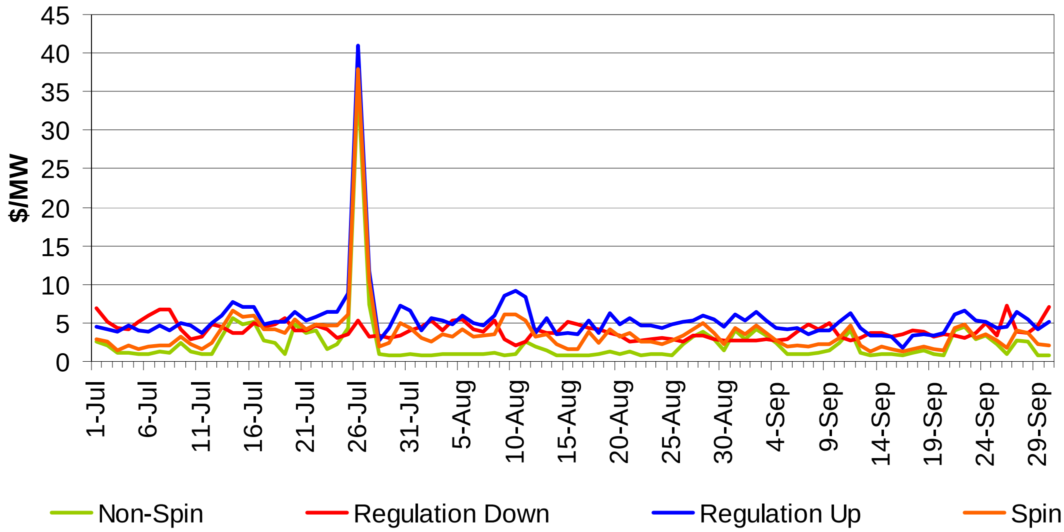
The hourly regulation up and regulation down procurements were relatively unchanged throughout the quarter, around 375 MW in each month. However, the procurement for spin increased 3.7 percent in August compared to July, and then fell 3.8 percent in September. Similarly, the procurement for non-spin increased 1.6 percent in August, and then fell 2.5 percent in September.

Table 4: IFM (Day-Ahead) Average Ancillary Service Procurement and Price

	Average Procurred				Average Price			
	Reg Up	Reg Dn	Spin	Non-Spin	Reg Up	Reg Dn	Spin	Non-Spin
Jul-09	375.16	375.00	929.44	923.35	$ 6.71	$ 4.45	$ 4.93	$ 3.54
Aug-09	375.46	375.00	963.66	937.75	$ 5.29	$ 3.68	$ 3.43	$ 1.42
Sep-09	375.00	375.00	927.04	914.09	$ 4.54	$ 3.82	$ 2.67	$ 1.95

The daily IFM average prices were stable for all four types of ancillary services for the quarter, falling into the range between $0/MWh and $10/MWh with an exception on July 26th. As mentioned in the previous section, all three default LAPs saw LMPs greater than $420/MWh in two hours on that day, which drove the hourly prices for regulation up, spin and non-spin above $350/MWh. The opportunity cost of resources providing ancillary services generated these higher prices.

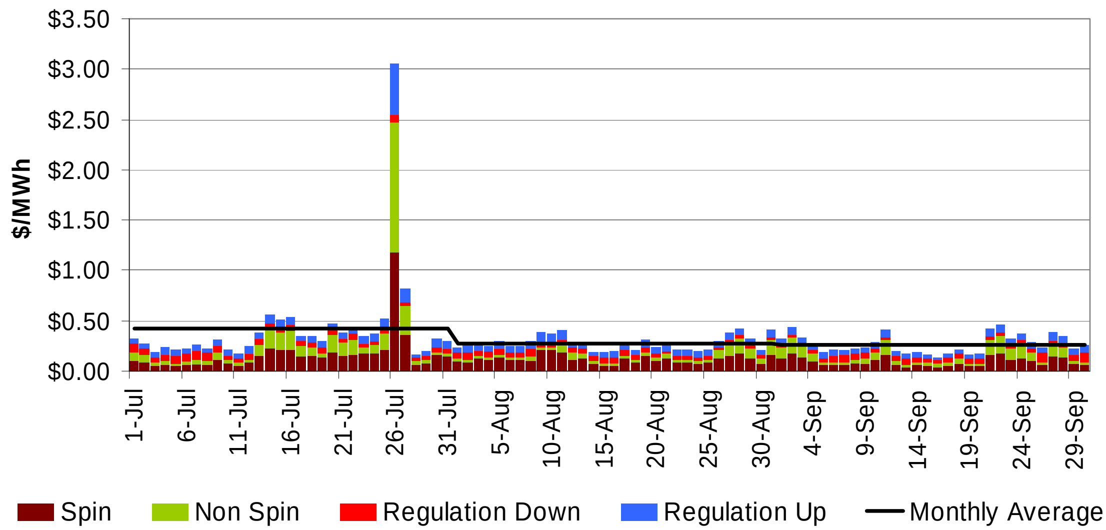
Figure 10: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Services Cost to Load

Figure 11 below shows the total system (day-ahead and real-time) average cost to load for ancillary services procured for the third quarter of 2009. The average cost of load for each type of ancillary services is calculated as the total hourly cost of procurement for that type of ancillary services divided by the total hourly ISO Load. The monthly average cost to load declined during the third quarter from $0.43/MWh in July to $0.27/MWh in September. The decline in cost to load largely resulted from a decline in the ancillary service requirement.

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



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 resulting costs. 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 12 presents daily RA/RMR RUC capacity and RUC award for the third quarter of 2009. Approximately 99.4 percent of RUC capacity was procured from RA or RMR units in the quarter. On July 27th, in an attempt to reduce the overall frequency of exceptional dispatch, the ISO began implementing generation procedures G-217 and G-219 in RUC on a trial basis. This resulted in a significant increase in the amount of RUC capacity procured after that date.

Figure 12: RA/RMR RUC Capacity vs. RUC Award (All Hours)

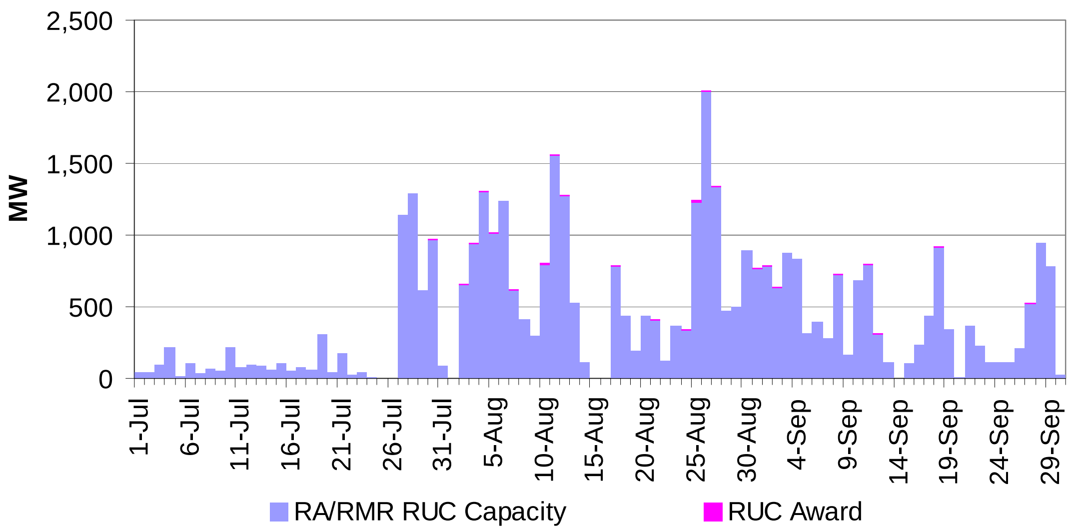
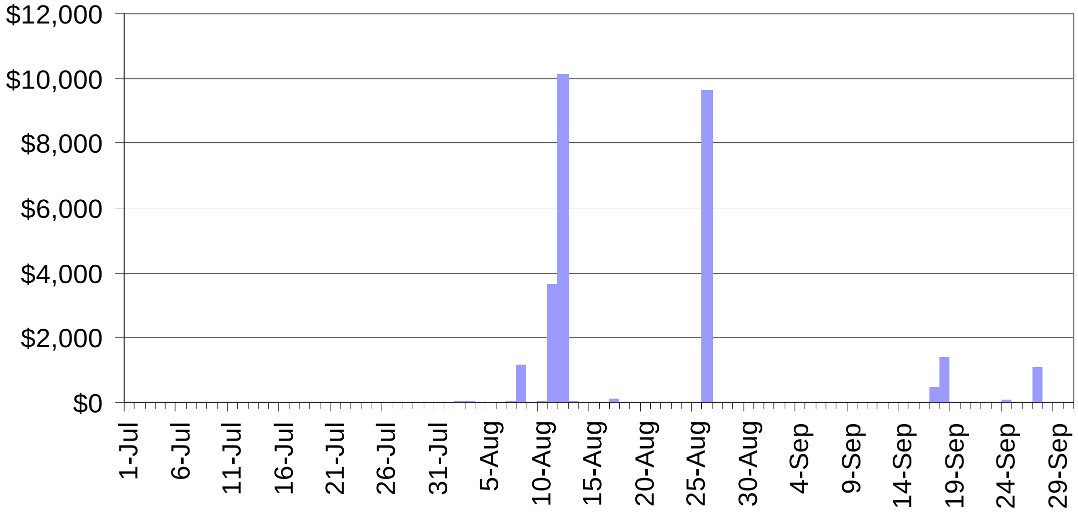


Figure 13 shows the daily cost of RUC procurement for each trading day for the third quarter of 2009. The monthly RUC procurement costs were $0, $24,888 and $3,006 in July, August and September, respectively. About 71 percent of the RUC cost for the quarter occurred in two days, August 12th and August 26th, while G-217 was binding, thereby increasing LMPs.

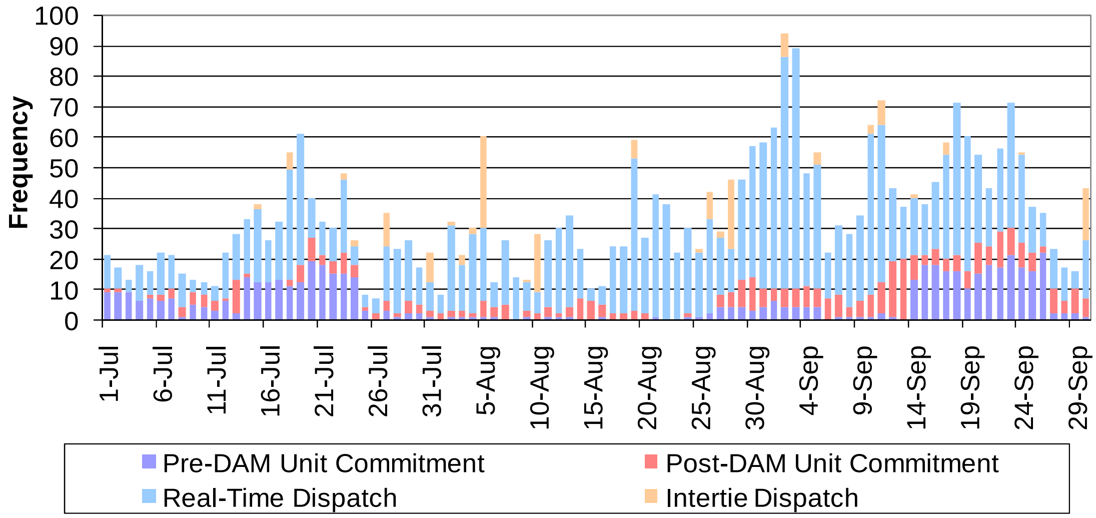
Figure 13: Total RUC Cost



Exceptional Dispatch

Figure 14 identifies instances of Exceptional Dispatches broken out by type of dispatch for the reporting period July 1 through September 30.[5] Approximately 94 percent of the Exceptional Dispatches were for internal generators and the remaining six percent were intertie dispatches. The average daily utilization rate in July was 25, followed by 30 in August and 48 in September.[6]

Figure 14: Summary of Exceptional Dispatch Frequency



5 Data used to generate this graph is based on preliminary settlements processing. The ISO will submit two exceptional dispatch reports for each calendar month to FERC based on September 2, 2009 Order Accepting Tariff Revisions, Subject to Modifications in Docket Nos. ER08-1178-003 and EL08-88-004 http://www.caiso.com/241d/241d9dee3ea40.pdf

6 For a more detailed analysis of Exceptional Dispatch, see the FERC informational filling October 20, 2009 120-day Exceptional Dispatch Report in Docket Nos. ER08-1178-000 and EL08-88-000 (Amendment to Tariff re: Exceptional Dispatch)

Cost of the Perfect Hedge[7]

This section reflects summarized information already presented in this report. Table 5 lists the monthly summary of both the day-ahead and the post-day-ahead (HASP/RT) congestion rents and perfect hedge costs. The ISO allocates congestion rent surplus or deficit 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. Table 5 reflects the cost charged to demand not holding ETC/TOR/CVR to honor the perfect hedge in comparison to the overall congestion cost of the day-ahead and post-day-ahead markets.

Table 5: 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
JULY	$6,751,414.96	-$1,014,383.41	-15.02%	-$303,537.38	-$3,231.63	1.06%
AUGUST	$4,555,114.23	-$450,968.18	-9.90%	-$614,940.69	-$29,444.74	4.79%
SEPTEMBER	$20,452,204.65	-$1,476,300.41	-7.22%	-$14,282,391.90	-$565,133.01	3.96%
Total	$31,758,733.85	-$2,941,652.00	-9.26%	-$15,200,869.97	-$597,809.37	3.93%

The cost of the perfect hedge to non-ETC/TOR/CVR loads in the DAM during the second quarter was $2.94 million, which represents 9.26 percent of the congestion rents collected in the IFM market, down from the 13.3 percent of the second quarter. 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 affected the CRR revenue adequacy. Because the auction revenues were sufficient to offset all the revenue deficiencies in July and August, the cost of the perfect hedge reduced the surplus to be distributed to non-ETC/TOR/CVR measured demand. Compared to the DAM costs, the cost of the perfect hedge in the real-time market was lower, about $0.59 million, most of that cost collected in September. The post day-ahead cost of the perfect hedge amounts to just 3.93 percent of the total congestion cost for this quarter, up from the 0.74 percent observed in the second quarter. Congestion revenues in RTM were a negative balance (deficit) and were allocated to non-ETC/TOR measured demand. The perfect hedge in each month of the third quarter was a payment to holders of rights, resulting in an additional cost to non-ETC/TOR loads that the net negative congestion rents.

[7] As required by FERC's Order Accepting Compliance Filing issued on September 22, 2006 (*California Indep. Sys. Operator, Corp.*, 116 FERC ¶ 61,281, (2009)), the ISO maintains a record of the redispatch costs associated with honoring ETCs/CVRs/TORs and charged to non-ETC/CVR/TOR loads and makes this information publicly available to market participants on the ISO website in the monthly market performance reports http://www.caiso.com/205c/205cb4c74bc40.html. In this section, the ISO provides a summary of that information over the third quarter of 2009.

Reliability – Compliance with NERC Reliability Standards[8]

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").[9] 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.[10] 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.[11]

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

[8] FERC Order Paragraph 1417: 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. ISO 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.
[9] 16 U.S.C. § 824o.
[10] *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).
[11] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

> 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.[12]

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."[13] 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."[14] 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).[15]

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. The ISO has not identified any negative impact of the ISO's new market design on standards compliance. WECC has just concluded its 3-year onsite audit of the ISO's NERC Standards compliance as well as a separate on-site spot check of NERC Critical Infrastructure Protection Standards. The preliminary findings of both reviews presented on October 16, 2009 were quite favorable and contained nothing to even remotely suggest that the new market design had an impact on compliance with NERC Standards.

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

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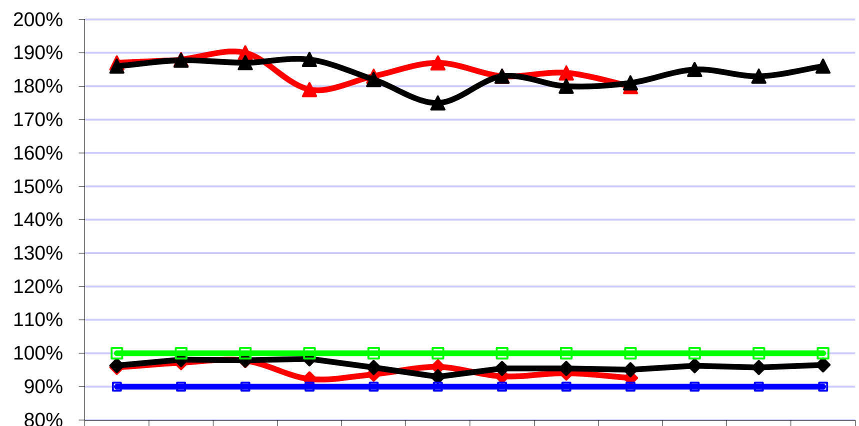
[12] *North American Electric Reliability Corp.*, 126 FERC ¶ 61,229, at P 9 (2009).
[13] 18 C.F.R. § 39.4(a).
[14] 18 C.F.R. § 39.4(b).
[15] *See* "WECC Compliance Monitoring and Enforcement Program," at § 4.1 (available on NERC's website at: http://www.nerc.com/files/WECC_2009_Implementation_Plan.pdf); http://compliance.wecc.biz/Application/ContentPageView.aspx?ContentID=74 (WECC web page regarding the CEMP).

particular, the Operations Highlights Report contains data indicating that, since implementation of its new market design, the ISO has 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 September 2009 demonstrates that the ISO has operated the grid in compliance with these Reliability Standards.

Figure 15 provides the CPS1 and CPS2 data for January through September 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%.

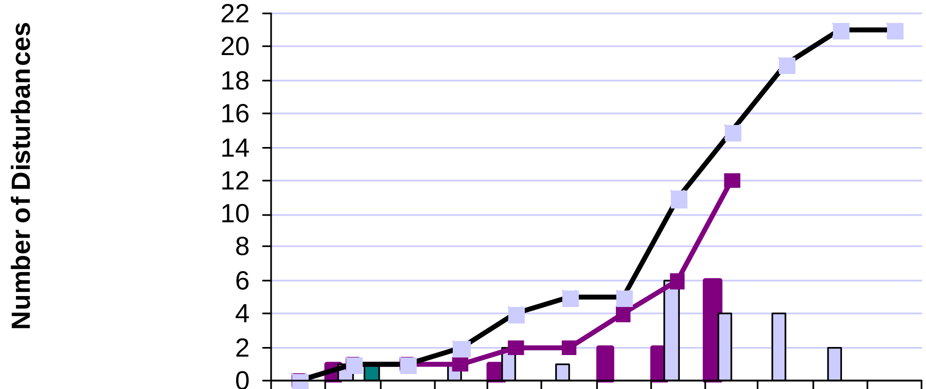
Figure 15: CPS1 and CPS2 Violations



	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
'09 CPS 1	187%	188%	190%	179%	183%	187%	183%	184%	180%			
'09 CPS 2	95.76	97.15	97.79	92.29	93.68	95.90	93.07	94.01	92.57			
'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 16 provides the DCS data for January through September 2009 as well as data for 2008 for comparison. For 2009 to date, the data show the number of DCS violations was zero.

Figure 16: 2008 and 2009 DCS Violations



	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Inside ISO '09	0	1	0	0	1	0	2	2	6			
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	0	0			
ISO DCS Violations '08	0	1	0	0	0	0	0	0	0	0	0	0
'09 YTD Disturbances Total	0	1	1	1	2	2	4	6	12			
'08 YTD Disturbances Total	0	1	1	2	4	5	5	11	15	19	21	21

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 *September 2006 MRTU 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 percent 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]

[16] This information is provided consistent with the *September 2006 MRTU Order*, Paragraph 1417: 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." 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:

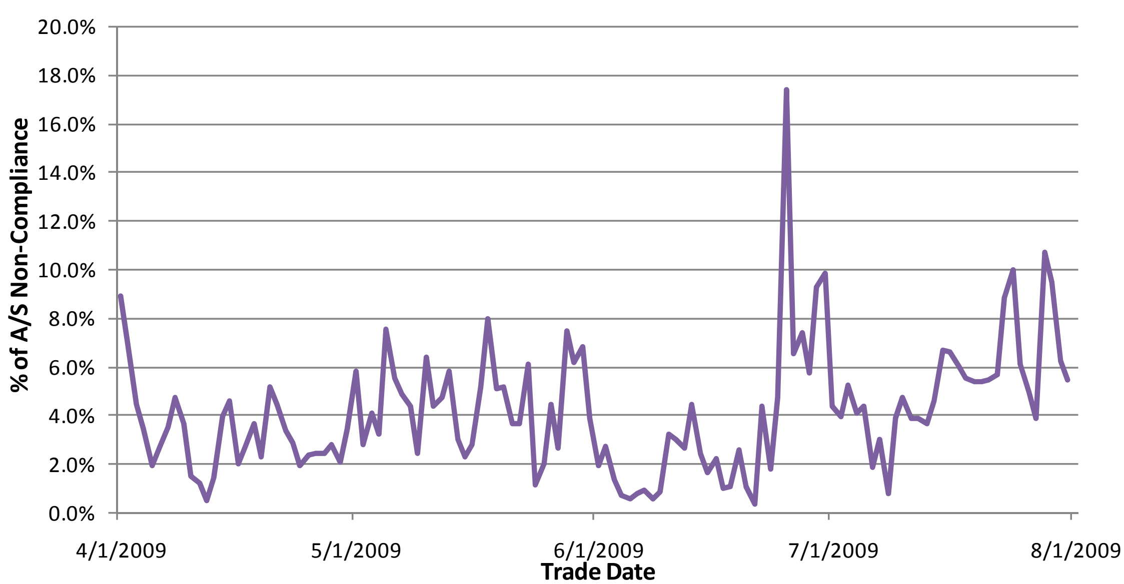
> "In order to ensure compliance with these standards, we direct the CAISO to include an assessment of the following in its quarterly, post-implementation performance reports: (1) the generating units of each participating generator scheduled to provide spinning reserve and non-spinning reserve are available 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).

- 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 provide Ancillary Services are available for dispatch throughout the entire settlement period [8.4.4i; Item 4 from *September 2006 MRTU Order* P 1417]
- 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; Item 2 from *September 2006 MRTU Order* P 1417]

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 17 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 from April to July 2009 as a proportion of the total spin and non-spin procured. The average level of non-compliance was 4.1 percent of the total spin and non-spin procured for the time period from April to July 2009. In the July 30th Report, the amounts for April 2009 were incorrectly reported and have been restated in Figure 17 below[17].

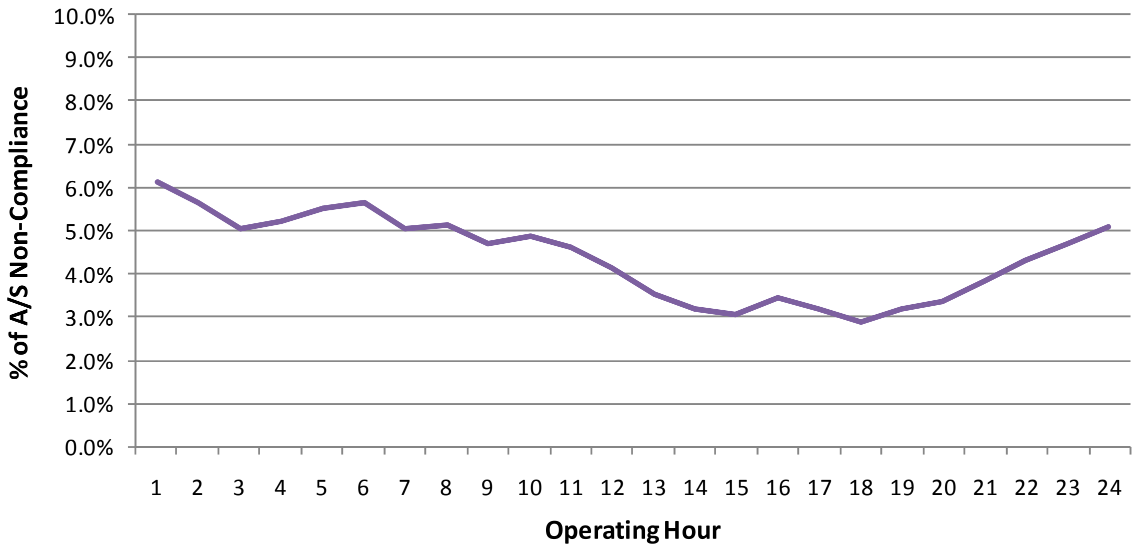
Figure 17: Daily Ancillary Service Non-Compliance from April to July 2009



[17] Amounts for Spin and Non-Spin Capacity procured were queried from Real-Time Market results which are reported every 15 minutes or 4 times per hour. As a result the Spin and Non-Spin Capacity was reported at a level four time higher than was actually scheduled in the ISO markets in the July 30th Report.

Figure 18 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 18: Hourly Trend of Non-Compliance in Percent



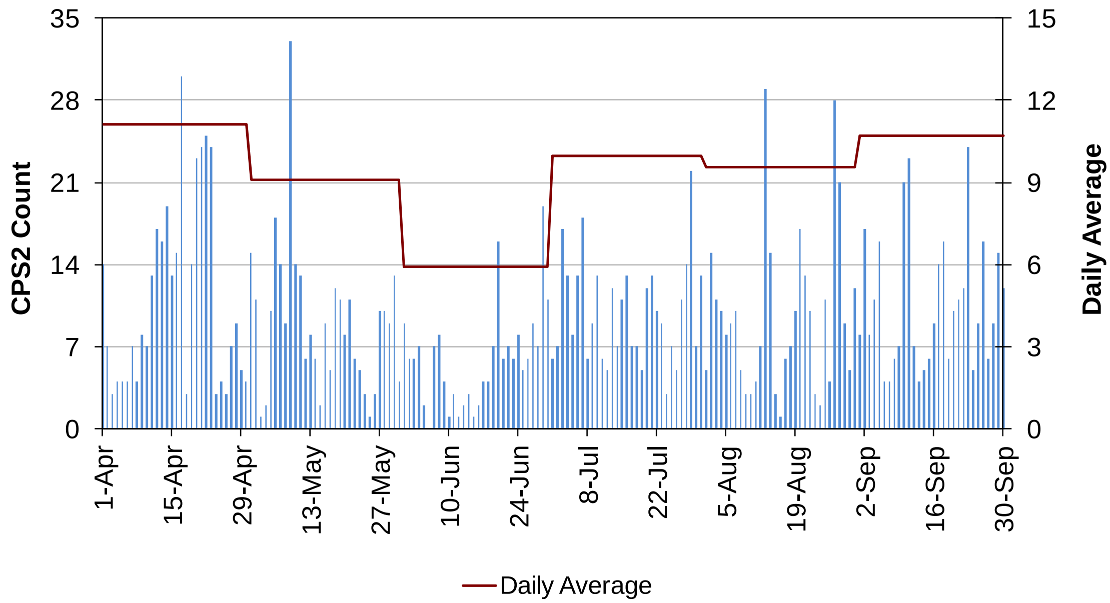
Area Control Error

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

The pattern of daily CPS2 violations is shown in Figure 19 below. The bars in blue are the total count of CPS2 violations per day, while the line in dark red is the daily average over each calendar month (cumulative violations in a month divided by the number of days in a given month).

Figure 19: 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."[18]

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. 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 CAISO Tariff 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.

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

Business Practice Manuals (PRRs)[19]

For the quarter ending September 30, 2009, two BPM PRR reports were delivered to the ISO Board of Governors for the July 20, 2009 and the September 10-11, 2009 Board meetings. No Board meetings were held in August, 2009. The BPM Change Management reports delivered to the ISO Board of Governors are attached to this report as Appendices 1 and 2.

[19]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[20]

There were no reported activities of bilateral transfers of RA Import Capability for this quarter. The ISO must also 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.

[20] In accordance with section 40.4.6.2.2.2 of the ISO Tariff, the ISO 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[21]

At the time of submission, the full settlements process is not complete for the third calendar quarter of 2009. Therefore, this report only includes data for the month of May through July based on the Monthly statement. Subsequent reports will provide this data as it becomes available.

During the month of June and July only one Schedule Coordinator was assessed a penalty. 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 ISO demand deviation is greater than fifteen (15) percent and less than twenty (20) percent of the maximum of the Scheduling Coordinator's cleared total ISO demand as represented in its Day-Ahead Schedule in its applicable LAP or its submitted Self-Schedule in its applicable LAP. The total penalties by trading date and LAP are summarized in Table 6.

Table 6: Summary of Interim Scheduling Charges

Trading Day	Number of SCs	Number of LAPs	Number of Trading Hours	USL Penalty
6/12/2009	1	1	2	$913.76
7/9/2009	1	1	4	$24,975.14
7/10/2009	1	1	2	$3,695.30
7/11/2009	1	1	3	$27,425.91
7/29/2009	1	1	1	$433.31

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

[21] Pursuant to Paragraph 37 of the Commission's July 17, 2008, order in Docket No. ER06-615-013, *California Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,043 (2008), the ISO will report aggregate data on interim scheduling charges. This section reports the Under-Scheduled Load (USL) penalty assessed to scheduling coordinators.

Deferred Functionality Items[22]

The ISO is committed to resolving the deferred functionality items and incorporating the four deferred items, as appropriate, into its 2009-2011 release plans. The timing of the deployment of items is dependent on the need for the functionality, 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.

1. Forbidden Operating Region

Prior to the operation of the ISO's new markets, the Commission approved the deferral of functionality that if implemented would have enabled the ISO to avoid dispatching 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 April 2010.

2. Limitation Changes in Operational Ramp Rates

Prior to the operation of the ISO's new markets, the Commission approved limiting 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) MSG, 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 November, 2009. Deployment of MSG is currently scheduled for April 1, 2010.

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[22] In accordance with the January 30, 2009 Deferred Items Order at P 4, 30, 41, 58, the Commission requires that the ISO report on the status of the ISO'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 ISO is further ordered to lay out a timeframe in which each of the functionalities can be restored and implemented. This section provides responsive information.

3. Procurement of Ancillary Services in the HASP

The ISO completed a stakeholder process to consider the reversion to procurement of Ancillary Services in HASP that was subsequently approved by the ISO Board of Governors in September 2009. The implementation date for this design is planned for April 1, 2010. A release planning workshop planned for November 10, 2009 will provide more details on the implementation plans for procurement of Ancillary Services in the HASP.

4. Extremely Long Start Process

Automation of the commitment process for extremely long-start resources may be of limited value since the ISO is already demonstrated reliably operation of its new market through the summer and fall of 2009 and has the ability to dispatch these resources through the process set forth in Tariff Section 31.7. The ISO is instead seeking to incorporate this functionality into an initiative to resolve multi-day unit commitment on a permanent basis. This functionality was one of the highest ranked initiatives in the ISO's 2009 market initiatives roadmap process. As a result, the ISO will, resources permitting, commence a stakeholder process next year to incorporate this functionality into its tariff and market software.

Evaluation of Uneconomic Adjustment Parameters[23]

Day-Ahead Market

The majority of market parameters that are used for adjusting non-priced quantities in the Day-Ahead Market optimization relate to transmission constraint relaxation and adjustment of self-schedules. Since the start-up of the ISO's new market on April 1, 2009, these parameters have only rarely affected the Day-Ahead Market results. No LMPs for Load Aggregation Points (LAPs), the location at which load is scheduled, have approached levels where adjustment of self-schedules for demand would occur. The ISO's review of market adjustments to self-schedules for generation and imports to date confirms that this mechanism is functioning as intended, with final schedules being adjusted to conform to transmission limits when effective generation or intertie schedules are available, producing energy prices at negative $30/MWh under such circumstances.[24] In the period addressed in this analysis, sufficient economic bids were generally available to enforce transmission limits without adjustments to self-schedules. The primary exception was for all hours of the day on September 13, following a forced outage that led to a derate of the Palo Verde intertie constraint (PALOVRDE_ITC), resulting in -$30/MWh prices at the Palo Verde scheduling point in all hours of the day. On subsequent days of this outage, sufficient economic bids were available to manage the constraint without adjustments to self-schedules.

When the relaxation of transmission constraints is necessary to resolve congestion, the market optimization resolves these constraints by pricing violations at $5000/MW in the initial scheduling run. The market optimization then determines the amount of constraint relaxation necessary. The adjusted

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[23] In its February 19, 2009 Parameters Order, (*California Ind. Sys. Operator Corp.*, 126 FERC ¶ 61,147 at P 82 (2009)) 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

In its answer to protests and comments filed in this proceeding, the ISO committed:

> "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."

[24] To resolve these types of constraints, the market optimization engine represents the supply self-schedules with an "uneconomic" bid segment price of $ 550/MWh in the initial scheduling run. The optimization then determines the amount by which these schedules require adjustment, using the uneconomic bid price. The uneconomic bid price consists of a segment between the original self-schedule and the adjusted self-schedule minus a small quantity known as epsilon where this bid segment is priced at negative $ 30/MWh. More negative bid segment prices apply during the scheduling run to the limited instances of Existing Transmission Contracts, Transmission Ownership Rights, or Regulatory Must Take resources. However, the volume of these bids has not exceeded the available transmission capacity. Consequently, this mechanism produces LMPs of negative $ 30/MWh at the location of the constrained self-schedule.

limit, plus a small epsilon value, is then passed to the pricing run at $500/MWh for capacity beyond the original limit. This mechanism produces shadow prices of the relaxed transmission constraints between $500 and $5000/MW. The congestion component of LMPs for resources whose incremental or decremental adjustment contributes to the constraint is the product of their Power Transfer Distribution Factor (PTDF, commonly known as "shift factor") and the shadow price of the transmission constraint.[25] For example, the congestion component of the LMP for a generator whose output adds to flows on a congested constraint with a shadow price of $500/MW, and that has a PTDF of 5% for the congested constraint, would be 0.05 * $500 = $25/MWh.

This mechanism has successfully limited the need to relax constraints while producing moderate LMPs. The following constraints have been relaxed in the Day Ahead Market during the period reported here:

- On 8/12/09, hour ending (HE) 12, 31000_HUMBOLDT_115_31001_HMBLT TM_ 1.0_XF_1 (a 115 to 60 kV transformer) was relaxed by 2.4 MW and the HUMBOLDT_BG corridor was relaxed by 1.5 MW, due to inadequate supply in the Humboldt area during a generation outage. Each of these constraints produced a pricing run shadow price of $500. LMPs for generation in the Humboldt area ranged from $448 to $871/MWh during this hour. Also on 8/12/09 due to the generation outage, in HE 14, 31000_HUMBOLDT_115_31001_HMBLT TM_ 1.0_XF_1 was relaxed by 0.1 MW, producing a shadow price of $500 in the pricing run, and HUMBOLDT_BG was binding at a shadow price of $212.96. LMPs for Humboldt generation in HE 14 ranged from $164 to $587.

- On 9/28/09, HE 8, HUMBOLDT_BG was relaxed by 4.6 MW, due to inadequate supply in the Humboldt area during a generation outage. This constraint produced a pricing run shadow price of $500, and LMPs for generation in the Humboldt area ranged from $541 to $543/MWh during this hour.

- On 9/10/09 in HE 17, on 9/11/09 in HE 15 to 18, and on 9/17/09 in HE 17, the 24807_MIRAGE _115_24819_CONCHO _115_BR_1 _1 115 kV line was relaxed by 0.2 to 14.1 MW ($500 in pricing run), resulting from contingency analysis with nearby outage. Shadow prices for this constraint were $500 in the pricing run in all of these hours except 9/17/09 HE 17, when the shadow price was $3036. The most effective generation for management of this constraint was 4.8 percent effective. This limited effectiveness resulted in the LMPs for these resources being held to a

[25] See Appendix C of the CAISO Tariff for further details.

maximum of $157/MWh on 9/10/09 and 9/11/09. LMPs reached a maximum of $636 on 9/17/09 for generation within the ISO area, and a minimum of $-202 at the Mirage intertie.

- On 9/17/09 in HE 13 to 17, the 35122_NWARK EF_115_35350_AMES BS _115_BR_2 _1 115 kV line was relaxed by 0.4 to 5.8 MW, with a pricing run shadow price of $500 in each hour. The most effective dispatchable resources for managing this constraint are 6.7 percent effective, resulting in the highest LMPs for the affected resources of $101/MWh.

- On 9/28/09 in HE 16 and 17, the 31990_DAVIS _115_31962_WDLND_BM_115_BR_1 _1 115 kV line was relaxed by 1.8 to 3.1 MW, with a pricing run shadow price of $500 in each hour. The most effective dispatchable resources for managing this constraint are 19.2 percent effective, which in this case has the result of reducing loading on the constraint by decreasing the generation output. As a result, this constraint produced LMPs of -$30/MWh for the affected resources, and resulted in reductions of the resources' self-scheduled output.

The software parameters used for constraint relaxation during the reporting period continue to provide reasonable pricing results and are set at the appropriate levels. The ISO will continue to monitor all instances of constraint relaxation in the Day-Ahead Market to ensure that the parameters continue to result in reasonable LMPs that reflect the system and market conditions.

Real-Time Market

Uneconomic adjustments or adjustments of non-priced quantities occur in the Real-Time Market optimization when there is an insufficient amount of economic bids to obtain a feasible and reasonable market solution. Since the implementation of the new markets, there has not been a significant amount of uneconomic schedule adjustments or adjustments of non-priced quantities in the real-time market. Additionally, data for the most recent quarter from July through September show that by almost every measure, there has been a significant reduction in uneconomic adjustments.

The following section provides an assessment of the non-priced quantity parameters that have been in place since April 1, 2009. Unless a Scheduling Coordinator explicitly submits an economic bid in the RTM for the RTM to use to dispatch the resource below its Day-Ahead Schedule for energy, a Scheduling Coordinator's day-ahead energy scheduled amount is effectively a self-schedule in the Real-Time Market. Such real-time self-schedule has a scheduling run price below -$500/MWh that governs any reductions for supply-side resources. Such reductions typically become necessary when a transmission derate occurs between the DAM and the RTM, because 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 quarter from July 1 to September 30, 16.09 percent of the intervals had one or more uneconomic adjustments in the RTD market solution. This reflects a slight increase from 15.53 percent over the first three months of new-market operation. 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

Supply energy self-scheduled in RTD may be curtailed 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 negative $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 an hourly basis in the day-ahead and in HASP 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. Subsequently, in the pricing run, the associated pricing parameter is set to negative $30/MWh, the bid floor, and is used to price the self-schedule curtailment of the supply resource.

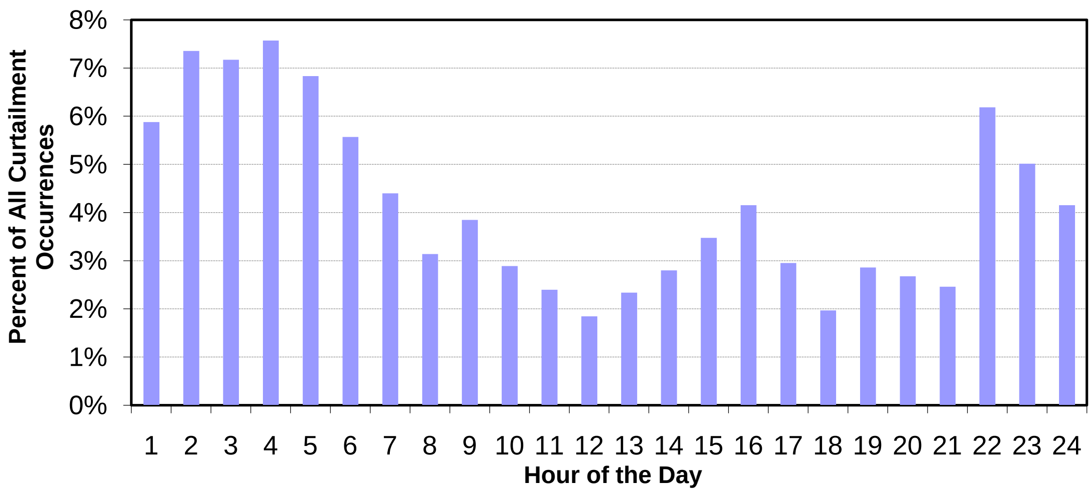
The ISO's analysis of the first two quarters of operation of the new markets reflects that the initial energy self-schedule parameter settings in RTD have been largely appropriate. Analysis of results from the first six months of new market operations shows that:

1. Self-schedule curtailments of internal generating resources and imports did not occur 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 default LAP (default load aggregation point including PG&E, SCE and SDG&E) prices were near or above the negative $30/MWh bid floor level. During periods of system-wide or large congestion area over-generation, the pricing run system LAP price and/or default LAP prices were usually around negative $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 negative $30/MWh level.

3. In rare instances, default LAP prices or system LAP prices in the pricing run have been significantly lower than negative $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 12.26 percent of the five-minute intervals. This is an increase from the previous quarter during which 10.48 percent of five-minute intervals had at least one uneconomic adjustment. The analysis also reveals that 60.1 percent of the quarter's uneconomic adjustments occurred during the month of July. The figure fell sharply in August to 20.66 percent of five-minute intervals, and to 19.24 percent of five-minute intervals in September. Figure 20 shows the curtailments as a percentage of the total occurrences for different hours of day over the quarter from July through September. 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 20: Percentage of Supply Energy Uneconomic Adjustment Curtailments by Hour



Over-generation system-wide or in large congestion areas occurred in 12.47 percent of intervals in which self-schedules were curtailed, (or 1.53 percent in the quarter). This is a dramatic decrease from the previous quarter. During these intervals, LAP prices for the over-generation area were near negative $30/MWh for 91.85 percent of intervals (or 1.40 percent of the quarter) and only 8.15 percent (or 0.12 percent of the quarter) LAP prices were more negative than negative $40/MWh. All of these figures reflect a significant decline in over-generation system-wide or in large congestion areas that could require self-schedule curtailments to resolve during the second quarter of new market operation. During the bulk of intervals in which energy self-schedules were curtailed, the curtailments were made to resolve local congestion, and thus default LAP prices were well above negative $30/MWh.

Export Energy

Curtailment of export energy self-scheduled 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/MWh is used for uneconomic adjustments of export self-schedules to achieve a market solution. Under normal circumstances, the export adjustment will not be carried out in actual operation. A higher penalty price is used for other higher priority export energy self-schedules. The pricing run pricing parameter is set at $500/MWh, the current energy bid cap, and is used to set the price for the self-schedule curtailment of the export resource.

Findings from the analysis of the July through September data are consistent with the ISO's second calendar quarter analysis, and show that the initial export self-schedule curtailment parameters have also been appropriate because:

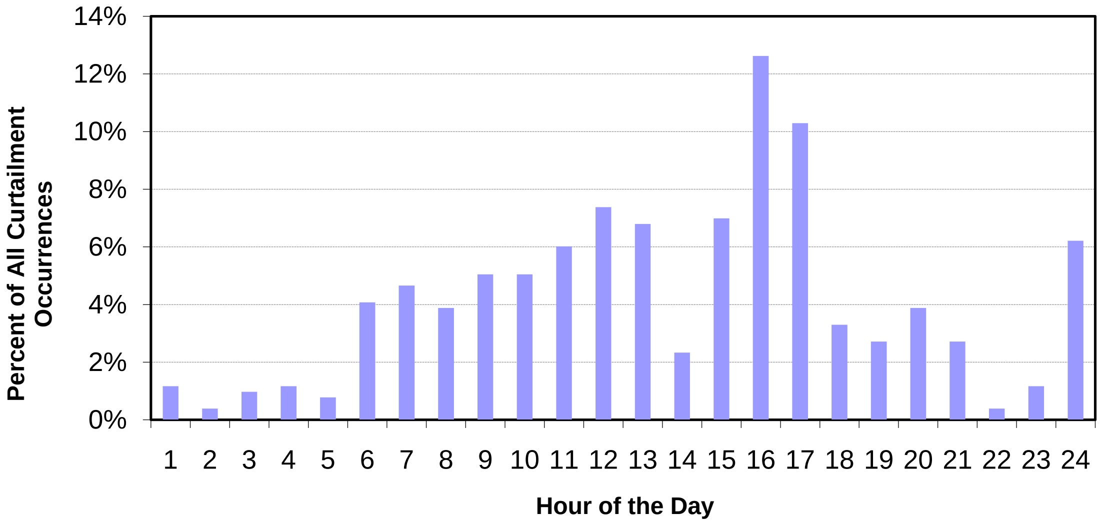
1. Self-schedule curtailment of exports has rarely occurred.
2. In instances where there were export self-schedule curtailments, the majority of the intervals had pricing run LMPs not significantly above the $500/MWh bid cap. Among such instances, pricing run system LAP and/or DLAP prices around $500/MWh 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/MWh level in localized areas but the resulting default LAP prices were well below the $500/MWh level.
3. In instances where there was export self-schedule curtailment, very small number of intervals (7.57 percent) had some default LAP 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, only a small number export energy self-schedules were curtailed over the period of this analysis.

The ISO's analysis reveals export energy uneconomic adjustments occurred in only 1.94 percent of the RTD intervals. Of those intervals, 39.81 percent, 29.51 percent and 30.68 percent occurred in July, August, and September, respectively.

Figure 21 shows the hourly adjustment occurrences (in terms of time intervals) in percent of total adjustment occurrences over the quarter from July 1 through

September 30. The chart indicates that the peak hours are more likely to have export energy self-schedule uneconomic curtailments.

Figure 21: Percentage of Export Energy Uneconomic Adjustments by Hour



Among the export self-schedule curtailments in RTD, supply-shortage system-wide or in a large congestion area occurred 41.75 percent of time (or 0.81 percent over the quarter). This is a decline of 50 percent from the previous quarter. LAP prices in the supply-shortage area were around $500/MWh in 34.17 percent of time (or 0.85 percent over the quarter) and above the $600/MWh level in 7.57 percent of time (or 0.15 percent over the quarter). These figures also reveal a dramatic decrease relative to the previous quarter. For the remaining curtailment intervals where curtailments were used to resolve congestion, default LAP prices were significantly below the $500/MWh bid cap for energy.

Transmission

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 the market has run out of exports to curtail from the area for which a market solution is sought. 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, which provides transmission constraints a higher priority over energy self-schedule curtailments. The pricing run pricing parameter for transmission constraint relaxation is $500/MWh, the current energy bid cap.

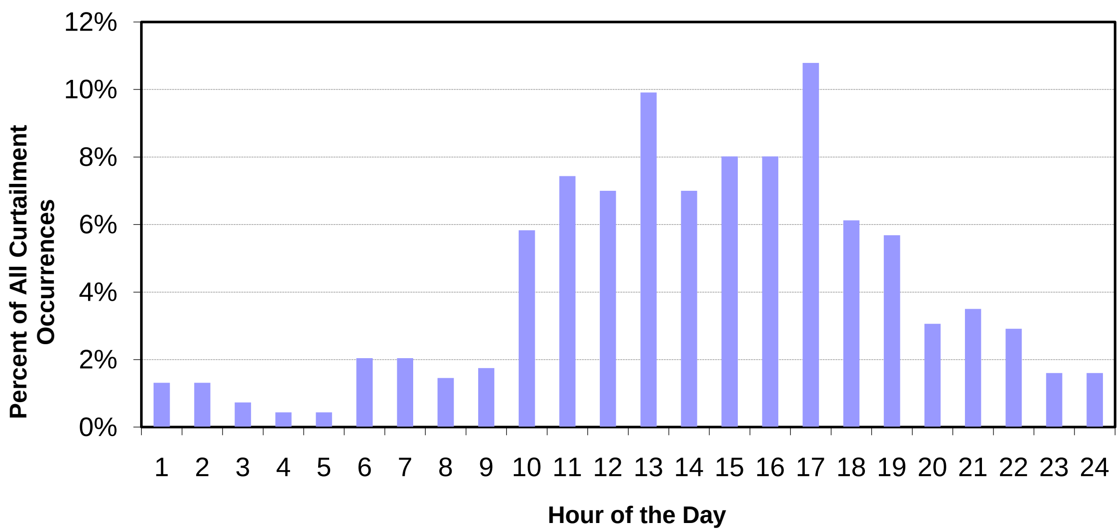
The ISO's analysis of transmission constraint relaxation during the first two quarters of new market operation shows that the initial parameter settings have performed as anticipated. Specifically the ISO has found that:

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 negative $30/MWh to $500/MWh. However, default LAP prices are well within the range.
3. In rare instances of large congestion area supply shortage, which required transmission constraint relaxation to bring in extra energy into the shortage area for a market solution and where default LAP prices would be expected in the $500/MWh range, on several occasions the pricing run default LAP prices in the shortage area rose to very high levels in the $2000/MWh to $5000/MWh range. The cause of such extreme high DLAP prices in pricing run has been identified as mathematical modeling issue in the linearized optimization formulation under the interaction between the transmission constraint using lossless shift factors as coefficients and the lossy power balance constraint using loss penalty factors as coefficients. This issue has been reported to FERC.

The RTD results show that transmission constraint relaxation occurred in 2.59 percent of the five-minute intervals of which 32.80 percent, 34.11 percent and 33.09 percent occurred in July, August, and September, respectively.

Transmission constraint relaxation in the market solution has declined noticeably over the six-month period since the new market startup on April 1, 2009. Figure 22 shows the hourly transmission constraint relaxation occurrences as a percentage of all curtailment occurrences. The chart, which is based on data from July through September, shows that transmission constraint relaxation in the market solution is more likely to occur during peak-hour intervals.

Figure 22: 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, 87.32 percent of time (or 2.26 percent over the quarter) 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. Default LAP prices were within the negative $30/MWh to $500/MWh range during these periods.

For the remaining 12.68 percent of the time when transmission constraint relaxation occurred (or 0.33 percent over the quarter), relaxation was needed for transferring energy to the supply shortage area. During large supply area shortage time intervals, default LAP prices of several thousand dollars were observed only twice, or 0.01 percent of time over the second quarter of 2009. The high prices were due to 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 and energy for which ancillary services awards 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.

Ancillary Services Minimum Requirement Relaxation

AS minimum requirement constraint relaxation is caused by a supply shortage in an AS region. The penalty price parameters for relaxing the minimum requirement for different types of AS in the scheduling run are set at $2500/MW for both regulation-up and regulation-down, and $2250/MW for spin and $2000/MW for non-spin. For the pricing run, the pricing parameters for constraint relaxation is $250/MW for all ancillary services types, which sets the floor value of the Marginal Price of the AS in a shortage condition. Economic bids could set the Marginal Price higher than $250/MW when the bids are combined with opportunity cost of the capacity for not providing energy.

During the months of July, August, and September 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 Marginal Prices of $250/MW.
3. In rare circumstances, the Marginal Price of the relaxed AS minimum requirement has been much higher than $250/MWh.

The RTPD market results for this third quarter show that out of the 8832 15-minute intervals, AS minimum requirement relaxation occurred in only four intervals or 0.045 percent of time. They are the four 15-minute intervals of September 27 HE 10. AS requirements relaxations were observed for all AS types including regulation up, regulation down, spin and non-spin. For each AS type, constraint relaxation occurred in multiple AS regions.

Energy self-schedule curtailment

In RTPD, energy self-schedule curtailment occurs in order to unload capacity so that such capacity can provide ancillary services under supply shortage situations. In RTPD, the same parameters discussed in the RTD section above are used to perform adjustments of self-schedules (uneconomic adjustments). An analysis of energy self-schedule curtailments in the RTPD for the purposes of providing ancillary services reveals that:

1. Energy self-scheduling curtailment for ancillary services provision occurs extremely infrequently - in only three 15-minute RTPD intervals within the quarter.
2. Among the RTPD intervals with resource undergoing self-schedule energy curtailments to provide ancillary services, the pricing run ASMP (AS marginal price) is as high as $1000/MWh.

Analysis of RTPD market results shows that out of the 8832 15-minute intervals in July, August, and September, energy self-schedule curtailment in RTPD occurred in only three intervals or 0.034 percent of time. All of the intervals occurred on September 27 in the hour ending 10. ASMP in these three intervals ranged from $250/MW to $1,026.95/MW.

Price Cap Use[26]

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, the ISO adjusts the congestion loss component to affect the total LMP equaling either $2500 or -$2500 as shown in the illustrative example of Table 7.

Table 7: Price Cap Example

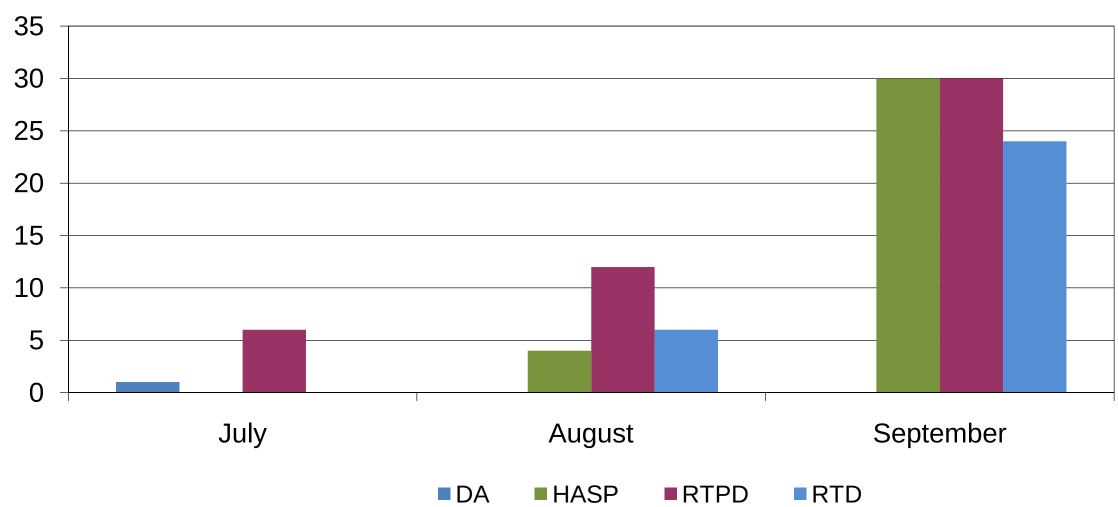
LMP Components	Original	Corrected
Energy	$2000	$2000
Congestion	$400	$300
Loss	$200	$200
LMP	$2600	$2500

[26] Pursuant to paragraph 39 of the FERC Price Cap Order (*California Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,082 (2009)), the ISO 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 responsive information.

Summary of Price Caps

Figure 23 shows the frequency with which the price caps were applied in the different market runs that procure products subject to the price cap from July 1st through September 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(procuring energy from the ties); 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). During the quarter, there were a total of 113 intervals during which the price cap was applied to prices at one or more nodes. The sole instance in which the price cap applied to the Day-Ahead Market was July 26th (explained in previous sections of this report).

Figure 23: Count of Price Caps



As shown in Table 8, the number of price caps for the remaining markets followed an increasing trend. On net, however, the third quarter saw a steep decline compared to the 344 instances of the second quarter.

Table 8: Summary of Price Caps

Month	DA	HASP	RTPD	RTD
July	1	0	6	0
August	0	4	12	6
September	0	30	30	24
Total	1	34	48	30

Price Cap Analysis[27]

The objective of this section of the quarterly report is to analyze the market runs where prices exceeded the price cap of $2,500, or the price floor of -$2,500[28].

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:

- 13 percent - Congestion or over-generation attenuated by the lossless shift factor effect, and
- 87 percent - Localized congestion involving the movement of multiple resources

Lossless Shift Factor[29] Effect

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 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.

Notable cases where this phenomenon occurred were: September 29, local congestion in Ventura and Santa Barbara counties due to reduced line limits set up for a contingency with adjacent lines out. The adjacent lines were out due to a wildfire.

[27] Per paragraph 39 of the FERC Price Cap Order: The ISO 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.

[28] Weekly reports that describe the price correction activities are published at the following location: http://www.caiso.com/237b/237b797854580.html

[29] 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.

Localized Congestion Involving The Movement Of Multiple Resources

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

Notable cases where this occurred were: August 30, local congestion in the Sacramento valley due to summertime flows; September 8 and 9, local congestion in Orange County due to planned maintenance; and September 17, local congestion in the San Francisco bay area due to planned maintenance.

Appendix 1
Business Practice Manuals
Change Management Report
July 10, 2009

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Karen Edson, Vice President of External Affairs

Date: July 10, 2009

Re: **Report on BPM Change Management Activities**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

The California Independent System Operator Corporation (the ISO) inaugurated the public change management process for business practice manuals (BPMs) on April 1, 2009. As part of the market redesign process, the ISO developed with stakeholders a transparent and detailed process to facilitate open discussion around BPM changes suggested by stakeholders or ISO staff. This memorandum is the first in an ongoing series, designed to inform the ISO Board of Governors (the Board) of the status of the BPM change requests submitted by stakeholders and the ISO.

BACKGROUND

At the direction of the Federal Energy Regulatory Commission (FERC), and as part of the market redesign and technology upgrade (MRTU) project, the ISO deployed a new change management process for the BPMs on April 1, 2009.

The BPM change management system and process were developed collaboratively by the ISO and stakeholders. This unique approach enables both stakeholders and the ISO to propose and track modifications to the BPMs, using the same electronic system. All changes to the BPMs, and BPM attachments and exhibits, are managed within the new process. The intent of the BPM change management process is to facilitate communication in a transparent manner, so that decisions can be made in light of all relevant information and in consideration of the effect of proposed changes on market participants.

Stakeholders expressed to the ISO the importance of a single system for proposing changes and commenting on proposed changes to the BPMs. Management concurred, leading to the development of the *Business Practice Manual for BPM Change Management*, which was approved by the Board and later filed with FERC.

The ISO is required by the tariff to submit a report on the status of BPM change management at each Board meeting. The report must include:

- the status of active proposed revision requests (PRRs);
- a summary of PRRs that, following a stakeholder process, have resulted in a change to the BPM; and
- a summary of PRRs that, following a stakeholder process, are rejected, with no changes made to the BPM. The summary of rejected PRRs must include the reasons for rejection and the stakeholders' positions.

Stakeholders and other interested parties can view the proposed revisions, track the process and comments posted, and submit and provide comments on PRRs, on the BPM change management system web site.

BPM CHANGE MANAGEMENT REPORT

The current *Board Update: BPM Change Management Process* report (the Report), which includes all the active PRRs from April 1, 2009 through June 30, 2009, is included as Attachment 1. In compliance with the tariff Board reporting requirements, the Report:

- provides a summary of the total number of active PRRs submitted by stakeholders and the ISO;
- summarizes the number of active PRRs in the various steps of the PRR lifecycle on June 30, 2009;
- reflects those PRRs upon which management posted its final decision; and
- includes PRRs under stakeholder appeal, the stakeholder positions on rejected PRRs, and the reasons for rejection.

Following is relevant information not required by the tariff and not reflected on the Report:

- No PRRs are under appeal;
- 12 PRRs were submitted by the ISO on an emergency basis, all of which were related to the Settlements and Billing BPM; and
- a PRR report summarizing the PRRs currently in the BPM change management system is included as Attachment 2.

Stakeholder Positions and Feedback

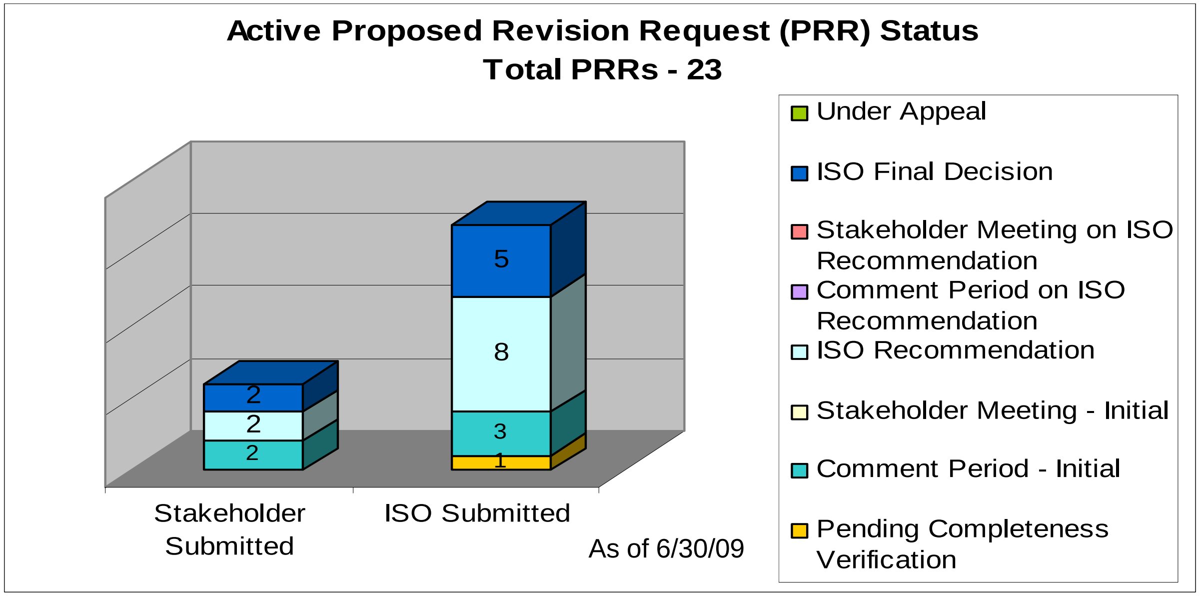
The BPM change management monthly stakeholder meetings were held on May 26, and June 23, 2009. Stakeholders are generally satisfied with the process and progress being made on the active PRRs.

At the stakeholder meeting on May 26, 2009, Management recommended an action on PRR No. 14, a request from Dynegy for clarification in the *Business Practice Manual for Market Operations*, to address treatment of start-up costs in day-ahead integrated forward market optimization. Management acknowledged the need to provide the requested information to stakeholders and posted a technical bulletin on June 16, 2009.

Board Update: BPM Change Management Process

July 20, 2009 Board Meeting

Attachment 1



Business Practice Manual (BPM)	# of PRRs
Compliance Monitoring	1
Congestion Revenue Rights	1
Market Operations	3
Rules of Conduct Administration	1
Settlements and Billing	17

Final Decisions Posted – April 1 to June 30, 2009

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	Final Decision
		No final decisions posted as of 6/30/09. This is a template to show how information will be organized.		

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Market Operations	PRR014	Detailing Treatment of Start-Up Costs in Day-Ahead IFM Optimization	6.6	A	4/29/2009	Dynegy	Normal	Decision Review	Final Decision
Rules of Conduct	PRR015	Revisions to implement CAISOs April 28, 2009 compliance filing in response to FERC Order 719 regarding market monitoring unit roles.	Entire Document	C	5/13/2009	ISO	Normal	Decision Review	Final Decision
Settlements and Billing	PRR016	Update CC 6011 BPM Configuration Guide formula sections to provide correct weighted average supply prices for an MSS Net electing entity.	CG CC 6011 Day Ahead Energy, Congestion, Loss Settlement	B	5/13/2009	ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	PRR019	Update the BPM document CC 6470 and Configuration to reflect Decremental Settlement of SYSEMR and SYSEMR1.	CG CC 6470 Real Time Instructed Imbalance Energy Settlement	B	5/20/2009	ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	PRR018	Update BPM Configuration guide CC 6700 to allow the proper congestion revenues to flow through to the CRR Balancing Account.	CG CC 6700 CRR Hourly Settlement	B	5/20/2009	ISO	Emergency	Decision Review	Final Decision
Congestion Revenue Rights	PRR017	Global Derating Factor for CRRs	10.3.3	A	5/20/2009	SCE	Normal	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR020	Update BPM Configuration guide for CC 372 to correct a Business Rule that reflects earlier configuration	CG CC 372 High Voltage Access Charge Allocation	A	5/27/2009	ISO	Normal	Recom-mendation	Comments on Recom-mendation

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing CAISO or Market Participants’ systems.
Category C - Significant new CAISO policies and/or revisions to the CAISO Tariff.

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Settlements and Billing	PRR021	Update BPM Configuration guide for CC 374 to correct a Business Rule that reflects earlier configuration	CG CC 374 High Voltage Access Revenue Payment	A	5/27/2009	ISO	Normal	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR023	Update BPM Configuration Guide for ETC, TOR, CVR quantity pre-calculation to correct formula for RTM congestion credits percentage	BPM Configuration Guide for ETC, TOR, CVR Quantity Pre-calculation	B	6/3/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR022	Formula Change to CC 6700 Section 3.6.1.2	CC 6700 -CRR Hourly Settlement	B	6/3/2009	PG&E	Urgent	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR029	Updated BPM Configuration Guide for CC 6480 to replace Measured Demand Quantity with Load Following Measured Demand Quantity for MSS	CC 6480 Excess Cost Neutrality Allocation	B	6/10/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR025	Update BPM Configuration guide for RTM Net Amount PC to exclude pumping revenues when resource is self-committed in IFM.	RTM Net Amount Pre-calculation	B	6/10/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR028	Updates to BPM Configuration Guide for CC 6489 to automate the allocation of EDE settlement amounts via a new input variable	CC 6489 Exceptional Dispatch Uplift Allocation	B	6/10/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR027	Update BPM Configuration guide to notify market participants a charge type is now calculated outside of Configuration	CG CC 6700 CRR Hourly Settlement	B	6/10/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing CAISO or Market Participants' systems.
Category C - Significant new CAISO policies and/or revisions to the CAISO Tariff.

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Settlements and Billing	PRR024	Update BPM Configuration Guide for IFM Net Amount PC to exclude pumping revenues and minimum load revenues when resource is self-committed in IFM.	IFM Net Amount Pre-calculation	B	6/10/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR030	Update the BPM Configuration Guide for CC 4503 to reflect attribute changes for BASettlementIntervalBalancedTORExport EnergyQuantity	CG CC 4503 GMC CRS Export	B	6/11/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Settlements and Billing	PRR026	Update BPM Configuration guide for Measured Demand over Control Are pre-calculation to allow the proper exemption of TOR contract rights from Measured Demand.	Pre-calculation Measured Demand over Control Area	B	6/11/2009	ISO	Emergency	Recom-mendation	Comments on Recom-mendation
Market Operations	PRR031	Clarification on transmission interface constraints modeling in market software	BPM Sections Requiring 3.2.4	A	6/17/2009	SCE	Normal	Comment Period	Stakeholder Meeting
Market Operations	PRR032	Clarification on the calculation of the system marginal energy cost (SMEC)	BPM Sections Requiring 3.2.2	A	6/17/2009	SCE	Normal	Comment Period	Stakeholder Meeting
Compliance Monitoring	PRR033	Dispatchable RUC Capacity	Section 7.2 Rescission of Payments for Undispatchable RUC Capacity for Generating Units, & Dynamic System Resources	B	6/24/2009	ISO	Emergency	Comment Period	Stakeholder Meeting

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing CAISO or Market Participants' systems.
Category C - Significant new CAISO policies and/or revisions to the CAISO Tariff.

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Settlements and Billing	PRR034	New BPM Configuration Guide for CC 6999 effective with Payment Acceleration	BPM Configuration Guide for Charge Code 6999 Invoice Deviation Interest Distribution	C	6/24/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR035	New BPM Configuration Guide for CC 7999 effective with Payment Acceleration	BPM Configuration Guide for Charge Code 7999 Invoice Deviation Interest Allocation	C	6/24/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR036	Update BPM Configuration guide for CC 6474 to reflect the settlement of UFE for interties based upon Hourly Real Time Checkout Intertie values and not Dispatch Interval Real Time Interchange Schedules.	CG CC 6474 Real-Time Unaccounted for Energy Settlement	B		ISO	Emergency	Pending	First Comments

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing CAISO or Market Participants' systems.
Category C - Significant new CAISO policies and/or revisions to the CAISO Tariff.

Appendix 2
Business Practice Manuals
Change Management Report
September 2, 2009

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Karen Edson, Vice President of External Affairs

Date: September 2, 2009

Re: **Required Briefing on BPM Change Management Activities**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memorandum is a regular monthly report required by the Federal Energy Regulatory Commission (FERC) to inform the ISO Board of Governors (Board) on the status of the Business Practice Manual (BPM) change requests submitted by stakeholders and the ISO.

The California Independent System Operator (the ISO) inaugurated the public change management process for business practice manuals (BPMs) on April 1, 2009. Both the ISO and stakeholders use the same electronic system and process to submit and track proposed changes to the BPMs. The process includes stakeholder review, ISO approval or rejection, and a possible appeal to three ISO officers.

As of August 19, 2009, 60 Proposed Revision Requests (PRRs) were active in the BPM change management system, 90% of which were submitted by the ISO. Twenty-two of the active PRRs are related to the Settlements and Billing BPM and 25 are related to the Transmission Planning Process BPM. No BPM decisions are under stakeholder appeal.

BACKGROUND AND PROCESS OVERVIEW

At the direction of FERC and as part of the market redesign and technology upgrade project, the ISO deployed a new change management process for the BPMs on April 1, 2009. The BPM change management system applies equally to stakeholders and the ISO. All changes to the BPMs, and BPM attachments and exhibits, are managed within the new process. The process enables both stakeholders and the ISO to propose and track modifications to the BPMs using the same electronic system.

Management developed the BPM change management process in response to stakeholder concerns about the possible lack of transparency on matters that affect their business interests. The overall process contained in the *Business Practice Manual for BPM Change Management* was approved by the Board in April 2007 and later filed with

FERC. Among FERC's requirements is that management submit to the Board a regular status report on the BPM change management process.

To propose a change to the BPMs, stakeholders or ISO staff member submit a (PRR) into the ISO's electronic system. Once verified as complete by the ISO, PRRs are available for review and comment within the electronic system for ten business days. Both the ISO and stakeholders can comment on any PRR, using the same electronic system. The ISO hosts a monthly stakeholder meeting to enable live dialogue on the active PRRs. After the monthly meeting concludes the ISO makes a recommendation for the proposed BPM change. Stakeholders are able to comment on the ISO's proposed recommendation, which is then discussed at the next monthly meeting. After considering stakeholder comments, the ISO posts its final decision on the PRR, at which time stakeholders can appeal the decision to the BPM Appeals Committee, which is comprised of three ISO officers.

The ISO held the monthly BPM change management stakeholder meeting on July 28, 2009. Conducted by conference call, the meeting included 15 stakeholders. Based on the nature of that meeting, and upon the types of comments being entered into the BPM change management electronic system, it appears that stakeholders are generally satisfied with the process, as well as with the progress being made on the active PRRs. No significant concerns are currently pending on the active PRRs.

One stakeholder submitted a PRR that the ISO subsequently determined is likely to require a tariff change. Management has referred the issue to the market design initiatives catalog for further policy consideration.

BPM CHANGE MANAGEMENT REPORT

The current *Board Update: BPM Change Management Process* report, which includes all the active PRRs as of August 19, 2009, is included as Attachment 1. In compliance with the tariff Board reporting requirements, the report:

- Summarizes the total number of active PRRs submitted by stakeholders and by the ISO;
- Depicts the number of active PRRs in various steps along the PRR lifecycle, as of August 19, 2009;
- Reflects those PRRs upon which Management has posted its final decision for the period June 30, 2009 through August 19, 2009; and
- Includes PRRs currently under stakeholder appeal, the stakeholder positions on rejected PRRs, and the reasons for rejection.

The following is additional relevant information:

- No PRRs are under appeal;

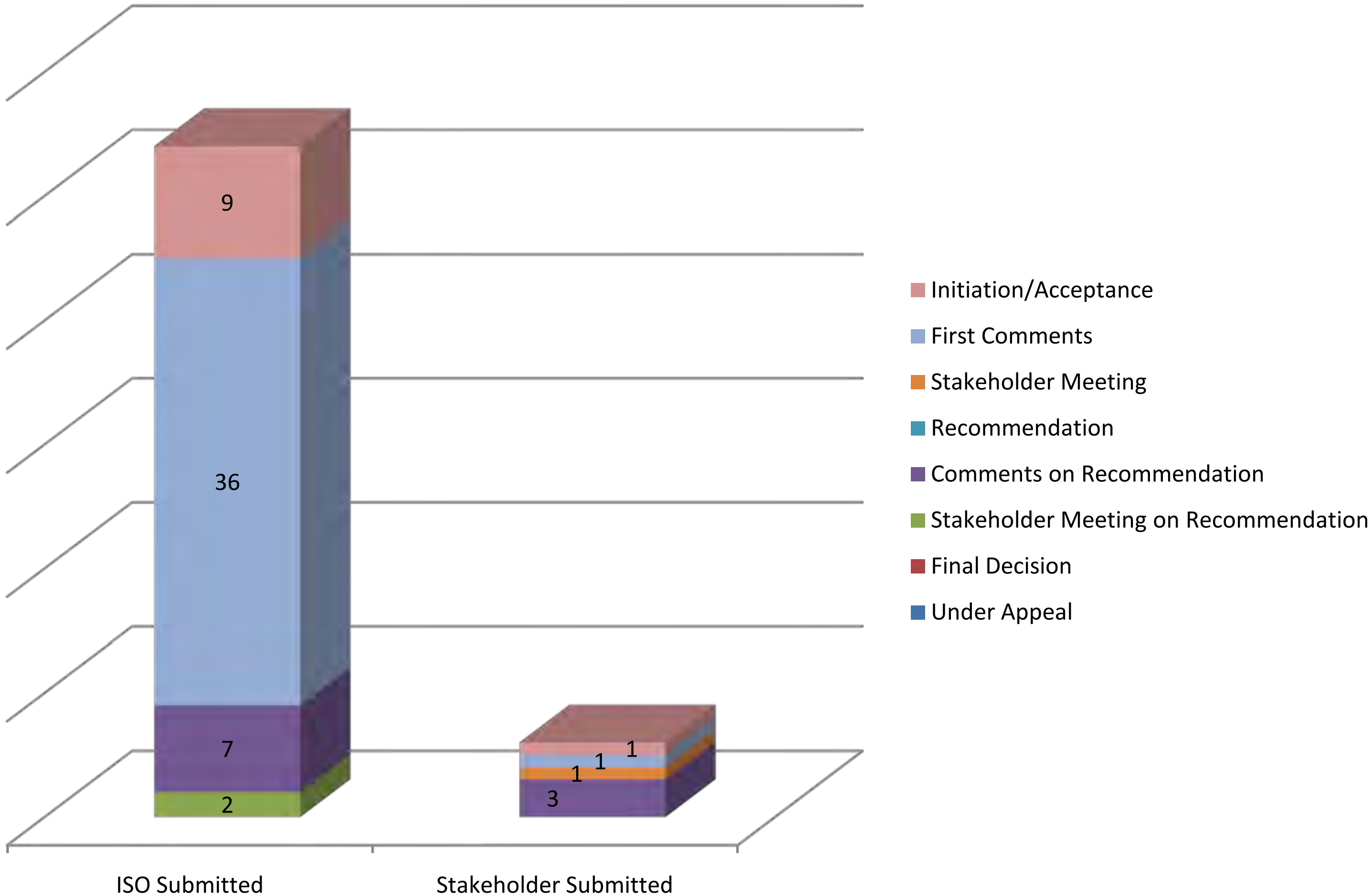
- Ten PRRs were submitted into the electronic system by the ISO on an emergency basis
    - eight of those PRRs were related to the Settlements and Billing BPM;
    - one PRR was associated with the Compliance Monitoring BPM; and
    - one PRR pertained to the Reliability Requirements BPM
- A PRR report summarizing the PRRs in the BPM change management system as of August 19, 2009, is included as Attachment 2.

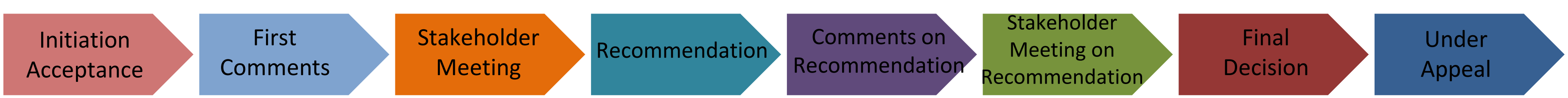
Attachment 1

ISO Board of Governors Update: BPM Change Management Process

September 10-11, 2009

Active Proposed Revision Request (PRR) Status





Active PRR Stage	# of PRRs
First Comments	37
Stakeholder Meeting	1
Comments on Recommendation	10
Stakeholder Meeting on Recommendation	2
Final Decision	10
Total	**60**

Business Practice Manual (BPM)	# of PRR's
Compliance Monitoring	1
Congestion revenue Rights	1
Credit Management	1
Managing Full Netowrk Model	2
Market Instruments	1
Market Operations	4
Metering	1
Reliability requirements	1
Rules of Conduct	1
Settlements and Billing	22
Transmission Planning Process	25
Total	**60**

Final Decisions Posted – 7/1/09 to 8/19/09

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Reject	14	Detailing Treatment of Start-Up Costs in Day-Ahead IFM Optimization	Process Complete	CAISO posted a technical bulletin in response to this PRR addressing the optimization details. SCE has posted a comment to this PRR and CAISO is requesting that SCE submit a new PRR to address the concerns raised in the comments.
Accept	15	Revisions to implement CAISO's April 28, 2009 compliance filing in response to FERC Order 719 regarding market monitoring unit roles.	Process Complete	The ISO adopts its recommendation, posted June 3, 2009, as issued. No comments were received on this PRR.
Accept	16	Update CC 6011 BPM Configuration Guide formula sections to provide correct weighted average supply prices for an MSS Net electing entity.	Process Complete	CA ISO decision is to adopt the recommendation. No comments were received.
Reject	17	Global Derating Factor for CRRs	Final Decision	BPM PRR 17: Final Decision The ISO will not modify any BPM language based on this BPM PRR, for the reasons indicated below: * The ISO started off with a 2% global de-rating factor for CRR revenue adequacy, based on our study paper issued in 2008, which recommended a range of 2-5%. Due to critical transmission outages, severe revenue inadequacy was experienced in April and May of 2009. Consequently, we adjusted the de-rating factor upward to 10% and then to 15%. Since this is an after-the-fact trial and error adjustment, we really did not have any detailed methodology to determine it. * The ISO is currently reporting the CRR revenue adequacy situation on a daily basis in the Daily Market Watch report, and analyzes CRR revenue adequacy in the Monthly Performance Reports. These reports provide analyses and explanations of the causes and implications of CRR revenue adequacy, regardless whether there is a surplus or shortfall of revenue of any magnitude. The reports can be retrieved from the ISO's public web site under the headings: Operations Center/Markets/Reports.

Final Decisions Posted – 7/1/09 to 8/19/09

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				* Due to the tight monthly process schedule, we cannot conform to 5 days of lead time prior to disclosing the value of the global de-rating factor before Tier 1 starts. It is not the ISO's intention to adjust the global de-rating factor in mid course between tiers. * It is not the ISO's intention to include the activity ¿evaluation of global de-rating factor¿ in the monthly schedules and checklists, which serve as reminders of key dates (external) market participants need to make note of. Evaluating the global de-rating factor is an internal process. * The ISO does not perceive ¿investigation of a separate global de-rating factor for interties NP15 & SP15¿ to be an appropriate BPM change. The studies of the 30-day outage rule will be revisited after 12 months of operational data becomes available (12 months after MRTU Go-Live). Three stakeholders indicated support for this PRR including the submitter and two commenters. One stakeholder requested an additional change, and the ISO's reason to reject this additional change is as follows: * The ISO will not provide a comparison of CRRs available for allocation and auction to the actual availability of the transmission system after outages. This kind of study is very involved, and the ISO cannot commit to this request at this point.
Accept	18	Update BPM Configuration guide CC 6700 to allow the proper congestion revenues to flow through to the CRR Balancing Account.	Process Complete	CA ISO's decision is to adopt the recommendation. No Comments were received.

Final Decisions Posted – 7/1/09 to 8/19/09

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	19	Update the BPM document CC 6470 and Configuration to reflect DecrementalSettlement of SYSEMR and SYSEMR1.	Process Complete	CA ISO's decision is to adopt the recommendation.
Accept	20	Update BPM Configuration guide for CC 372 to correct a Business Rule that reflects earlier configuration	Process Complete	CA ISO's decision is to adopt this change. No comments received.
Accept	21	Update BPM Configuration guide for CC 374 to correct a Business Rule that reflects earlier configuration	Process Complete	CA ISO's decision is to adopt this change. No comments received.
Accept	23	Update BPM Configuration Guide for ETC, TOR, CVR quantity pre-calculation to correct formula for RTM congestion credits percentage	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications
Accept	24	Update BPM Configuration Guide for IFM Net Amount PC to exclude pumping revenues and minimum load revenues when resource is self-committed in IFM.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	24	Update BPM Configuration Guide for IFM Net Amount PC to exclude pumping revenues and minimum load revenues when resource is self-committed in IFM.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	25	Update BPM Configuration guide for RTM Net Amount PC to exclude pumping revenues when resource is self-committed in IFM.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications
Accept	26	Update BPM Configuration guide for Measured Demand over Control Are pre-calculation to allow the proper exemption of TOR contract rights from Measured Demand.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.

Final Decisions Posted – 7/1/09 to 8/19/09

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	27	Update BPM Configuration guide to notify market participants a charge type is now calculated outside of Configuration	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	28	Updates to BPM Configuration Guide for CC 6489 to automate the allocation of EDE settlement amounts via a new input variable	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	29	Updated BPM Configuration Guide for CC 6480 to replace Measured Demand Quantity with Load Following Measured Demand Quantity for MSS	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	30	Update the BPM Configuration Guide for CC 4503 to reflect attribute changes for BASettlementIntervalBalancedTORExport EnergyQuantity	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Market Operations	PRR014	Detailing Treatment of Start-Up Costs in Day-Ahead IFM Optimization	6.6	A	4/29/2009	Dynegy	Normal	Process Complete	NA
Rules of Conduct	PRR015	Revisions to implement CAISOs April 28, 2009 compliance filing in response to FERC Order 719 regarding market monitoring unit roles.	Entire Document	C	5/13/2009	ISO	Normal	Process Complete	NA
Settlements and Billing	PRR016	Update CC 6011 BPM Configuration Guide formula sections to provide correct weighted average supply prices for an MSS Net electing entity.	CG CC 6011 Day Ahead Energy, Congestion, Loss Settlement	B	5/13/2009	ISO	Emergency	Process Complete	NA
Congestion Revenue Rights	PRR017	Global Derating Factor for CRRs	10.3.3	A	5/20/2009	Southern California Edison	Normal	Decision Review	NA
Settlements and Billing	PRR019	Update the BPM document CC 6470 and Configuration to reflect DecrementalSettlement of SYSEMR and SYSEMR1.	CG CC 6470 Real Time Instructed Imbalance Energy Settlement	B	5/20/2009	ISO	Emergency	Process Complete	NA
Settlements and Billing	PRR018	Update BPM Configuration guide CC 6700 to allow the proper congestion revenues to flow through to the CRR Balancing Account.	CG CC 6700 CRR Hourly Settlement	B	5/20/2009	ISO	Emergency	Process Complete	NA
Settlements and Billing	PRR021	Update BPM Configuration guide for CC 374 to correct a Business Rule that reflects earlier configuration	CG CC 374 High Voltage Access Revenue Payment	A	5/27/2009	ISO	Normal	Process Complete	NA
Settlements and Billing	PRR020	Update BPM Configuration guide for CC 372 to correct a Business Rule that reflects earlier configuration	CG CC 372 High Voltage Access Charge Allocation	A	5/27/2009	ISO	Normal	Process Complete	NA
Settlements and Billing	PRR023	Update BPM Configuration Guide for ETC, TOR, CVR quantity pre-calculation to correct formula for RTM congestion credits percentage	BPM Configuration Guide for ETC, TOR, CVR Quantity Pre-calculation	B	6/3/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR022	Formula Change to CC 6700 Section 3.6.1.2	CC 6700 -CRR Hourly Settlement	B	6/3/2009	Pacific Gas & Electric	Urgent	Stakeholder Meeting	Final Decision

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing CAISO or Market Participants' systems.
Category C - Significant new CAISO policies and/or revisions to the CAISO Tariff.

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Settlements and Billing	PRR025	Update BPM Configuration guide for RTM Net Amount PC to exclude pumping revenues when resource is self-committed in IFM.	RTM Net Amount Pre-calculation	B	6/10/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR029	Updated BPM Configuration Guide for CC 6480 to replace Measured Demand Quantity with Load Following Measured Demand Quantity for MSS	CC 6480 Excess Cost Neutrality Allocation	B	6/10/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR024	Update BPM Configuration Guide for IFM Net Amount PC to exclude pumping revenues and minimum load revenues when resource is self-committed in IFM.	IFM Net Amount Pre-calculation	B	6/10/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR027	Update BPM Configuration guide to notify market participants a charge type is now calculated outside of Configuration	CG CC 6700 CRR Hourly Settlement	B	6/10/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR028	Updates to BPM Configuration Guide for CC 6489 to automate the allocation of EDE settlement amounts via a new input variable	CC 6489 Exceptional Dispatch Uplift Allocation	B	6/10/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR030	Update the BPM Configuration Guide for CC 4503 to reflect attribute changes for BASettlementIntervalBalancedTORExportEnergyQuantity	CG CC 4503 GMC CRS Export	B	6/11/2009	ISO	Emergency	Decision Review	NA
Settlements and Billing	PRR026	Update BPM Configuration guide for Measured Demand over Control Are pre-calculation to allow the proper exemption of TOR contract rights from Measured Demand.	Pre-calculation Measured Demand over Control Area	B	6/11/2009	ISO	Emergency	Decision Review	NA
Market Operations	PRR032	Clarification on the calculation of the system marginal energy cost (SMEC)	BPM Sections Requiring 3.2.2	A	6/17/2009	Southern California Edison	Normal	Comment Period	Final Decision

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BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Market Operations	PRR031	Clarification on transmission interface constraints modeling in market software	BPM Sections Requiring 3.2.4	A	6/17/2009	Southern California Edison	Normal	Comment Period	Final Decision
Compliance Monitoring	PRR033	Dispatchable RUC Capacity	Section 7.2 Rescission of Payments for Undispatchable RUC Capacity for Generating Units, & Dynamic System Resources	B	6/24/2009	ISO	Emergency	Stakeholder Meeting	Final Decision
Settlements and Billing	PRR034	New BPM Configuration Guide for CC 6999 effective with Payment Acceleration	BPM Configuation Guide for Charge Code 6999 Invoice Deviation Interest Distribution	C	6/24/2009	ISO	Normal	Comment Period	Final Decision
Settlements and Billing	PRR035	New BPM Configuration Guide for CC 7999 effective with Payment Acceleration	BPM Congfiguration Guide for Charge Code 7999 Invoice Deviation Interest Allocation	C	6/24/2009	ISO	Normal	Comment Period	Final Decision
Settlements and Billing	PRR036	Update BPM Configuration guide for CC 6474 to reflect the settlement of UFE for interties based upon Hourly Real Time Checkout Intertie values and not Dispatch Interval Real Time Interchange Schedules.	CG CC 6474 Real-Time Unaccounted for Energy Settlement	B	7/1/2009	ISO	Emergency	Comment Period	Final Decision
Settlements and Billing	PRR037	Update BPM Configuration guide for Measured Demand over Control Are pre-calculation to eliminate a flag input associated with TOR contract rights in a Metered Demand calculation for UFE.	BPM Configuration Guide Measured Demand over Control Area Pre-calculation	B	7/8/2009	ISO	Emergency	Comment Period	Final Decision
Market Operations	PRR039	New Expected Energy Types	Appendix C Section C.4.1	B	7/8/2009	ISO	Urgent	Stakeholder Meeting	Final Decision

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BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Market Instruments	PRR038	Master File Update (User Interface)	Appendix B Master File Update Procedures	B	7/8/2009	ISO	Normal	Comment Period	Final Decision
Settlements and Billing	PRR043	Update the BPM CG for RT Price Pre-calculation to reflect the substitution of the appropriate Pnode or Apnode Dispatch Interval Price where Resource Specific Price is NULL.	CG PC Real Time Price PC	B	7/15/2009	ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR041	Update the BPM 6475 RT Uninstructed Imb Energy to reflect the settlement of Uninstructed Imbalance Energy for resources that did not schedule in the DA Market yet they either produced generation as instructed or uninstructed, or had demand served.	CG CC 6475 Real Time Uninstructed Imbalance Energy	B	7/29/2009	ISO	Emergency	Comment Period	Final Decision
Settlements and Billing	PRR042	Update the BPM 6774 RT Cong Offset to reflect the settlement of Congestion revenue for resources that did not schedule in the Day-Ahead Market yet produced generation or had demand served as well as MSS resources that have elected NET settlement.	CG CC 6774 Real Time Congestion Offset	B	7/29/2009	ISO	Emergency	Comment Period	Final Decision
Settlements and Billing	PRR044	Update the BPM Configuration Guide formula for 6620 precalculation to include exports in bid cost recovery calculation	6620 Settlements & Billing BPM Configuration Guide Pre-calculation	B	7/29/2009	Citigroup Energy Inc	Urgent	Stakeholder Meeting	Recommendation
Transmission Planning Process	PRR067	Information to be submitted with Request Window proposals to include generation in the TPP study process.	3.3.2 Generation Project Proposals	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR072	Definition of Maintenance Projects	3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting

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BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Transmission Planning Process	PRR076	Detailed NERC Reliability Assessment Studies	A. Table of contents; B.2.1.1.2 Coordination of the Meeting, Planning and Study Responsibilities; C. Attachment 2	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR065	Modifications to language describing Economic Planning Studies	3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR063	Amending the Transmission Plan	A. New section: 2.2.2 & B. 4.3.4	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR059	Request Window submissions can be approved by ISO Executive Management during Stage 3, from November through February, under certain circumstances.	A. 2.1.2.4 & B. 4.3.1	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR045	Update BPM Configuration Guide for Start Up and Minimum Load Cost to prevent duplication of eligible SUC whenever a resource has multiple commitment periods in a Trading Day.	BPM Configuration Guide for Start-Up and Minimum Load Cost Pre-calculation	B	8/5/2009	ISO	Emergency	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR057	Changed language to say if needed the ISO will host additional public meetings to discuss the results from the PTOs.	2.1.2.3 Stage 2: Technical Studies and Presentation of Results	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Managing Full Network Model	PRR073	Communicate FNM updates to WECC	5.1.2 FNM Data Gathering	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR071	Non-approval notification process for projects other than Large Projects	New section titled: 4.3.3 Rejection Process	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR070	Large Project non-approval notification process	4.3.2 Large Project Evaluations	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR069	Non-substantive modification of Large Project description	4.3.1 Timeframe for Project Approvals	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting

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BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Transmission Planning Process	PRR068	Circumstance under which projects will be recommended for ISO Board of Governors approval	4.3.1 Timeframe for Project Approvals	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR066	Modifications to the Secondary Validation Response Period.	3.2 Request Window Submission Process	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Managing Full Network Model	PRR046	FNM Update Process Flow Digaram - Update	5.1 - Exhibit 5.1	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR047	Update BPM CG for Metered Energy Adjustment Factor to (a) ensure Wheel Energy does not receive BCR uplift payments, (b) Total Pumping Energy is considered, (c) eliminate incorrect Metered Energy Adjustment Factors.	BPM Configuration Guide for Metered Energy Adjustment Factor Pre-calculation	B	8/5/2009	ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR048	Updated BPM Configuration Guide for ETC, TOR, CVR Quantity Recalculation to implement New Bill Determinant for contract entitlement used in DA Energy contract balancing	CG PC ETC, TOR, CVR Quantity Precalculation	B	8/5/2009	ISO	Emergency	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR049	Reliability projects are to be submitted by PTOs by October 15.	A. 2.1 The ISO Transmission Planning Process & B. 2.1.2.3 Stage 2: Technical Studies and Presentation of Results	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR050	Request Window submissions must respond to the needs identified by the ISO	A. 2.1.1.2 B. 2.1.2.1 C. 2.1.2.3	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR051	The NERC Reliability criteria violation recommended solution	A. 2.1.1.2 B. 4.2	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR052	General Description of Request Window Categories	2.1.2.1 Request Window	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting

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BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Transmission Planning Process	PRR053	The transmission owner of the system to which a generation will be interconnected to must submit network upgrades through the Request Window.	2.1.2.1 Request Window	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR054	Generation projects must go through the GIPR in order to interconnect to the ISO Grid.	A. 2.1.2.1 Request Window & B. 3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR055	Categories of Request Window Submissions	2.1.2.1 Request Window	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR056	The ISO will post general descriptions of all Request Window submission to its public website and the submission packages to its secure website on a bi-weekly basis.	A. 2.1.2.1 Request Window & B. Proposed new section titled: 3.5 Posting Request Window Submissions	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR058	Modified/reorganized language regarding Stage 3 output.	2.1.2.4 Stage 3: Project Approval Process and Development of the Transmission Plan	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR060	Projects with an estimated capital investment of less than $50 million that are approved by ISO Executive Management will receive approval letter.	2.1.2.4 Stage 3: Project Approval Process and Development of the Transmission Plan	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR061	Language modification to clarify Transmission Plan designation.	2.2 ISO Transmission Plan	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Transmission Planning Process	PRR062	Section 2.2.1 clarification and reorganization	New section titled: 2.2.1 Contents of the Transmission Plan	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting

Category A - Language, grammatical errors and/or minimal impact.
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BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATETGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Transmission Planning Process	PRR064	Adds section heading for existing BPM language	New section titled: 2.2.3 Compliance with NERC Reliability Standards	A	8/5/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Credit Management	PRR075	Revisions to the BPM for Credit Management to reflect changes resulting from Payment Acceleration	4.1; 6.1; 6.2; and 6.3	B	8/7/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Rules of Conduct	PRR074	Revisions for Payment Acceleration	various	A	8/7/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Market Operations	PRR078	New Expected Energy Calculation schedule effective with Payment Acceleration	Appendix C Section C.6	A	8/7/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR077	Edits to incorporate Payment Acceleration principles, changes to Historic Rerun PTB amount presentation, and other content clarification edits.	Various sections of Settlements & Billing Main Body and Attachment B	B	8/7/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Metering	PRR079	Metering BPM update to reflect Payment Acceleration implementation	1.2 to 10.8 (see breakdown in Additional Qualitative Information)	A	8/7/2009	ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	PRR080	Formula changes to section 3.6.1 and 3.6.2	Metered Energy Adjustment Factor Pre calc Sec 3.6.1 and 3.6.2	A	8/19/2009	Ventyx	Normal	Comment Period	Stakeholder Meeting
Reliability Requirements	PRR081	Update Reliability Requirements BPM Exhibit A-2 with due dates for 2010 submittals	Exhibit A-2	A	8/19/2009	ISO	Emergency	Comment Period	Stakeholder Meeting

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing CAISO or Market Participants' systems.
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Attachment B
DMM Quarterly Report

California Independent
System Operator Corporation

California ISO

Quarterly Report on MRTU Market Design Issues

October 30, 2009

Prepared by: Department of Market Monitoring

1 Introduction

This report addresses two issues identified by the Federal Energy Regulatory Commission (FERC) to be addressed in by the Department of Market Monitoring (DMM) quarterly reports to be filed with FERC after implementation of the CAISO's new market design.

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

2 Mitigation Based on Bid-In Demand vs. ISO Forecast

2.1 Background

In the ISO's May 2005 MRTU FERC filing, the ISO proposed to base the pre-IFM MPM 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 Order on Rehearing, later directed the ISO to base the pre-IFM MPM runs on bid-in demand, citing concerns by some stakeholders that 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 MPM runs on forecasted demand rather than bid-in demand, noting that changing the IFM software to use bid-in demand in MPM could substantially delay implementation of the new market design.

In its September 2006 Order, FERC granted rehearing to allow the ISO to use forecast demand, rather than bid-in demand, for the pre-IFM MPM 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 Order, FERC also directed the ISO's market monitor to monitor 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, and include these findings in the CAISO quarterly status reports.[3]

2.2 Analysis

DMM has the capability to re-run the IFM using a standalone copy of Siemens' market simulation software used in the ISO's new day-ahead market. However, the pre-IFM MPM process incorporated in the standalone 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 MPM on bid-in demand,

[1] September 2005 Order, 112 FERC ¶ 61, 310 at 69.

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

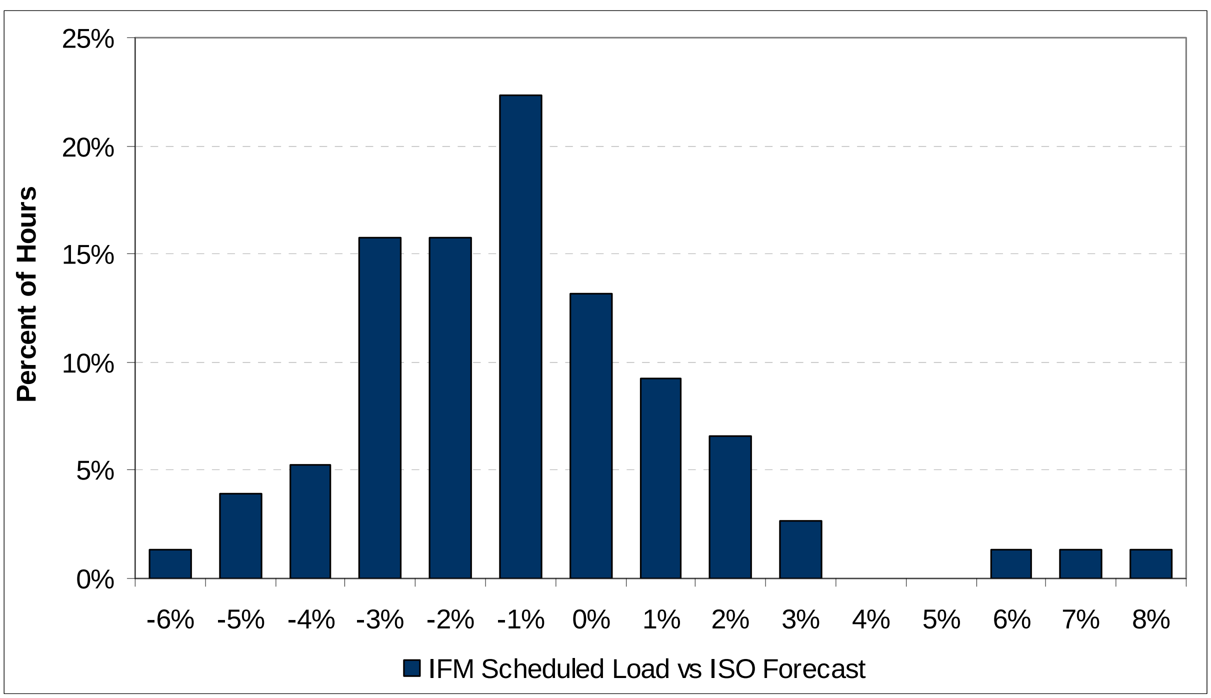
[3] April 2007 Order, 119 FERC ¶ 61, 076 at P 496.

DMM has developed the capability to modify the load forecast used by the software to approximately equal the level of demand that actually cleared the IFM (i.e., given actual bid-in demand). Results of 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 MPM 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. Since the primary concern with the use of forecasted demand cited by the Commission and some stakeholders is that this 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 second three months of the IFM.

Figure 2.1 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 in Q3 of 2009 (July through September). As shown in Figure 2.1, 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 limited impact on the level of mitigation that has occurred due to any under-scheduling in the IFM. Data shown in Figure 2.1 were also utilized by DMM to select a sample of four different days for more detailed analysis using the DMM's standalone IFM software, as described below.

Figure 2.1 Differences between Load Scheduled in IFM and ISO Forecast Daily Peak Hour, July – September 2009



For this Q3 report, DMM focused on the extreme over and under scheduling days since it was determined in the Q2 report that typical levels of under and over scheduling of load clearing the IFM compared to ISO's load forecast had negligible impact on mitigation[4]. Results for the four sample days analyzed for this report are summarized in Table 2. 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 2., these results further indicate that use of bid-in rather than forecast demand in the pre-IFM MPM procedures could be expected to have a negligible impact on the level of mitigation in the IFM, and on final IFM schedules and prices. For example:

- On the sample day with the highest level of under-scheduling in the IFM relative to the ISO's load forecast (6 percent on August 11), the analysis showed that use of bid-in demand had a negligible impact on the degree of mitigation in the IFM. On this day, case study results show that use of bid-in demand instead of the forecast would increase mitigation by one unit or 81 MW during the peak hour.[5] Moreover, on this sample day, average prices in the IFM decreased by about one percent under the scenario used to estimate the impacts of basing MPM on bid-in demand. Such results are counterintuitive, since basing MPM on a lower level of demand would be expected to decrease mitigation and decrease the pool of resources considered in the IFM.[6] 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.[7]

- On the sample day with the second highest level of under-scheduling in the IFM relative to the ISO's load forecast (5 percent on August 30), the analysis showed that use of bid-in demand had a negligible impact on the degree of mitigation in the IFM. On this day, case study results show that use of bid-in demand instead of the forecast would decrease mitigation by two units or 87 MW during the peak hour. Average prices remained relatively unchanged under the scenario used to estimate the impacts of basing MPM on bid-in demand.

- On the sample day with the second highest level of over-scheduling in the IFM relative to the ISO's load forecast (7 percent on July 26), the analysis showed that use of bid-in demand increased mitigation marginally and greatly reduced average prices. On this day,

[4] For Q2-2009 results, refer to DMM's "Quarterly Report on Market Issues and Performance – Q2-2009" report which can be found on the ISO website at: http://www.caiso.com/23fb/23fbed164b6b0.pdf.

[5] See final right most column in Table 2.1, labeled "Impact of Mitigation during Peak Hour, MW (Q_{IFM} - Q_U)". For a description of these metrics, see Attachment A of this report.

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

[7] 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 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 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).

case study results show that use of bid-in demand instead of the forecast would increase mitigation by one unit or 26 MW during the peak hour. Average prices decreased by about 46 percent under the scenario used to estimate the impacts of basing MPM on bid-in demand. However, analysis of results for this day indicates that this decrease in price is not attributable to bid price mitigation but instead due to the fact that the pool of units considered in the IFM is greater under this scenario, since additional resources are dispatched in the pre-IFM AC run.[8] The result of this sample day is similar in nature to the June 21, 2009 sample day discussed in the Q2 report where IFM schedules were 6 percent above ISO load forecast.

- On the sample day with the highest level of over-scheduling in the IFM relative to the ISO's load forecast (8 percent on September 6), the analysis showed that use of bid-in demand increased mitigation and marginally reduced average prices. On this day, case study results show that use of bid-in demand instead of the forecast would increase mitigation by two units or 396 MW during the peak hour. Average prices decreased by about one percent under the scenario used to estimate the impacts of basing MPM on bid-in demand.

[8] On October 2, 2009, the ISO filed to modify the ISO's tariff so that bid for all resources would be considered in the IFM, rather than only bids that are dispatched in the AC run. **http://www.caiso.com/243e/243e8ccecd70.pdf**

Table 2.1 Analysis of Mitigation Based on Forecast Rather than Bid-in Demand

		Units with Bids Lowered due to Mitigation			Impact of Mitigation during Peak Hour	
	Daily Avg Cost	**Total Unit/Hours Mitigated**	**Units Mitigated in Peak Hour**	**Bids Subject to Mitigation in Peak Hour (Q_{MAX} - Q_{CC}) ***	**Units with Higher Dispatch**	**MW (Q_{IFM} - Q_U)***
6% Underscheduling / Peak Forecast = 41,885 MW (August 11)						
Base	$36.55	69	4	71	0	0
MPM w/IFM MW	$36.17	71	3	401	1	81
Change	**-1%**	**2**	**-1**	**330**	**1**	**81**
5% Underscheduling / Peak Forecast = 39,282 MW (August 30)						
Base	$31.89	70	4	529	4	319
MPM w/IFM MW	$31.85	69	3	519	2	231
Change	**0%**	**-1**	**-1**	**-10**	**-2**	**-87**
7% Overscheduling / Peak Forecast = 37,117 (July 26)						
Base	$86.40	42	3	195	0	0
MPM w/IFM MW	$46.88	60	3	399	1	26
Change	**-46%**	**18**	**0**	**204**	**1**	**26**
8% Overscheduling / Peak Forecast = 31,484 MW (September 6)						
Base	$36.55	31	1	145	0	0
MPM w/IFM MW	$36.17	63	3	541	2	396
Change	**-1%**	**32**	**2**	**396**	**2**	**396**

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

3 Frequently Mitigated Units

3.1 Background

The Local Market Power Mitigation (LMPM) 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 (DEBs) for resources not under Resource Adequacy (RA) or Reliability Must run (RMR) contracts that are frequently mitigated. Resources not under RA or RMR contracts 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 opportunity for supplemental revenue for recovery of going-forward fixed costs for 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 RMR agreements or RA contracts receive revenues for recovery of going-forward fixed costs of this capacity, non-RA/RMR capacity is 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.[9] The bid adder, if elected by the FMU, can only be added to their cost-based DEBs. A negotiated option is available also for resources that believe the default of $24/MWh is not accurate in the context of recovering their going-forward fixed cost.[10]

In FERC's June 25, 2007 Order on Compliance, 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

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

[10] Section 39.8 of the CAISO Tariff at http://www.caiso.com/23d5/23d5cd07a480.pdf

whether the FMU option should be modified to reflect broader compensation levels for units mitigated less than 80 of its run hours. [11]

3.2 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 start of the ISO's new market (April 1, 2009), the *mitigation frequency* used to determined eligibility for the FMU adder is based on a rolling twelve month combination of data from the ISO's prior market design and this new market design.

- During the period prior to April 1, 2009, RMR and Out-of-Sequence (OOS) 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 MPM-RRD procedures in Sections 31 and 33 of the CAISO Tariff. If a unit is subject to mitigation in either the IFM or RTM during any hour, that hour is counted as a mitigated hour in their mitigation frequency. It is important to note for purposes of this FMU calculation, a unit is considered to be *mitigated* if its dispatch in All Constraints (AC) run of the market software is greater than the unit's dispatch in the Competitive Constraints (CC) run of the market software. [12]

Frequently Mitigated Units in Q3 2009

Every month, DMM provides Potomac Economics, an independent entity contracted by the ISO to calculate DEBs, 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 DEBs.

Figure 3.1 shows the monthly count of FMUs categorized by unit type: RMR, RA, partial RA, and non-RMR/RA units. During each month of Q3 2009, at least two units have been mitigated in at least 80 percent of their run hours during the prior twelve month period. In all the three months of July, August and September the units that met the mitigation frequency criteria were

[11] P 352 of the June 25, 2007 Order on Compliance Filing.

[12] In practice, as discussed in DMM's first *Quarterly Report on Market Issues and Performance,* a significant portion of units subject to mitigation may actually have a portion of their bids *lowered* due to mitigation. See *Quarterly Report on Market Issues and Performance*, prepared by Department of Market Monitoring, July 30, 2009, pp 30-37, ***http://www.caiso.com/23fb/23fbed164b6b0.pdf***

either under RMR or had all of their capacity under RA contract and thus were not eligible for the FMU bid adder.

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 LMPM procedures. The overall frequency of mitigation of non-Ra/RMR units has been relatively limited during the third quarter of 2009. This is illustrated in Table 3.1, which shows the total run hours and frequency of mitigation of the seven non-RA/RMR generating units within the ISO system during the July to September 2009 period that were subject to bid mitigation. As shown in Figure 3.1, while limited number of combined cycle units not under RA or RMR contract in Q3, these units had relatively high run hours and were subject to mitigation only a small portion of these hours (≤ 5 percent of hours).

Figure 3.1 Number of Resources, by Contract Status, That Exceeded Mitigation Frequency for Prior 12 Months

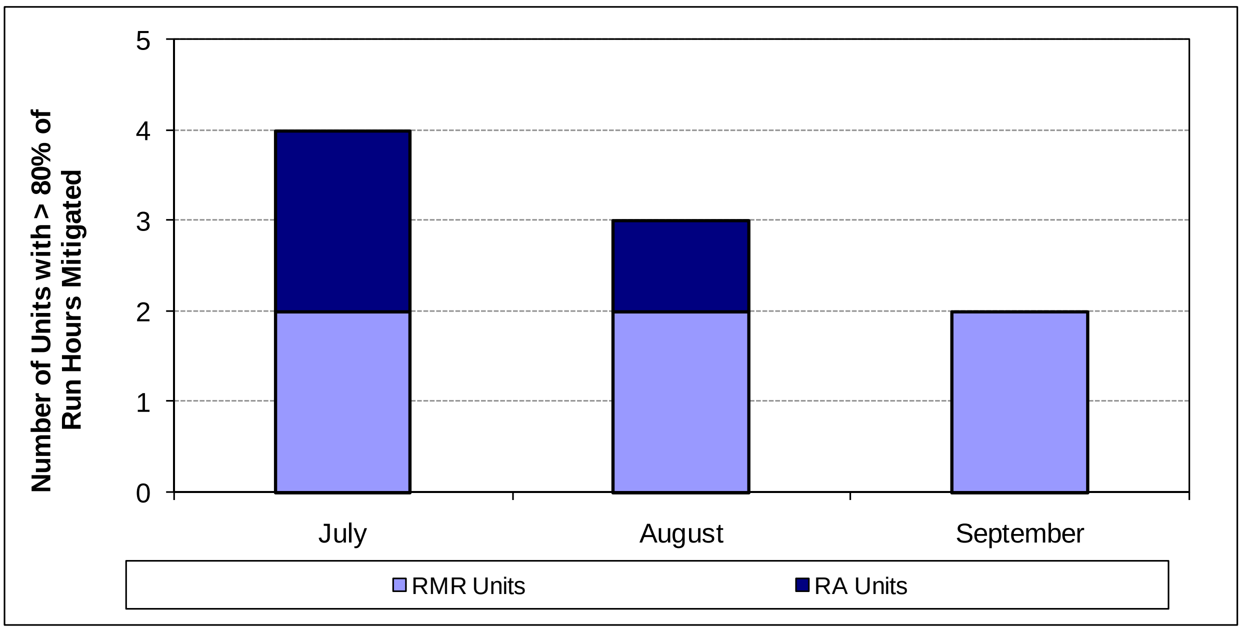


Table 3.1 Mitigation Frequency of Non-RA/RMR Resources in Q3 2009

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*	292	13%	7	2%
Combined Cycle	198	9%	2	1%
Combined Cycle	301	14%	1	0%
Combined Cycle	2,153	99%	2	0%

* Unit not listed as RA since it is used for load following by its owner under a Metered Subsystem (MSS) agreement.

Attachment A: Metrics Used to Assess Impacts of Bid Mitigation

The analysis of the impacts of the use of forecasted versus bid-in load in the pre-IFM LMPM procedures provided in; Section 2 of this report includes several metrics used to quantify the actual degree and impact of bid mitigation occurring under different market scenarios (see Table 2.1 of this report). This attachment provides a more detailed description of these metrics and how they were calculated.

Figure A.1 illustrates how the LMPM 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 (CC) enforced. The CC 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 (AC) enforced. Units which are dispatched at a higher level in this AC run than in the first CC run are subject to bid mitigation. As illustrated in

Figure A, the unit's initial market bid is subject to mitigation since its dispatch in this second AC run (Q_{AC}) is greater than its dispatch in the first CC run (Q_{CC}). The unit's highest market bid dispatched in the CC run is used as a *floor* below which the unit's bid is not mitigated, even if this exceeds the unit's DEB (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 DEB for energy above the unit's dispatch level in the CC run. This final mitigated bid is then used in the IFM. A similar LMPM process is performed prior to the real time market during the HASP process.

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

- **Units With Market Bids Lowered Due to Mitigation.** As shown in

Figure A, the total quantity of a unit's initial unmitigated market bid that can potentially be lowered as a result of LMPM procedures extends from the unit's highest bid dispatched in the CC 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 CC 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 DEBs.

- **Bids from Mitigated Units Dispatched in IFM.** As shown in

Figure A, 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 LMPM procedures is actually dispatched in the IFM. As illustrated in

Figure A, this quantity is calculated based on the difference between each units' dispatch in the CC run (Q_{CC}) and its actual IFM schedule (Q_{IFM}).

- **Increase in Dispatch due to Mitigation.** Finally, as shown in Figure A.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., it is assumed that the unit's dispatch in the IFM (Q_{IFM}) is greater than its dispatch in the CC and AC 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 units unmitigated bid curve below the IFM price was less than the unit's dispatch in the CC 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 CC run ($Q_U \geq Q_{CC}$). The net effect of this constraint is to simply 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 CC run based on its unmitigated bids (Q_{IFM} - Q_{CC}).

Figure A.1 Bid Mitigation

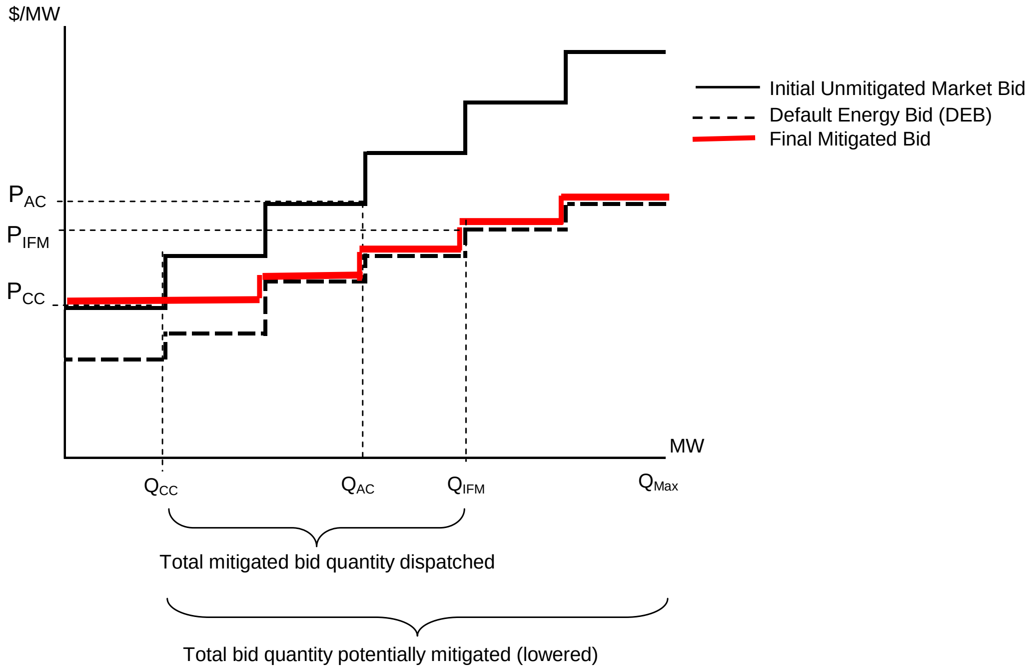
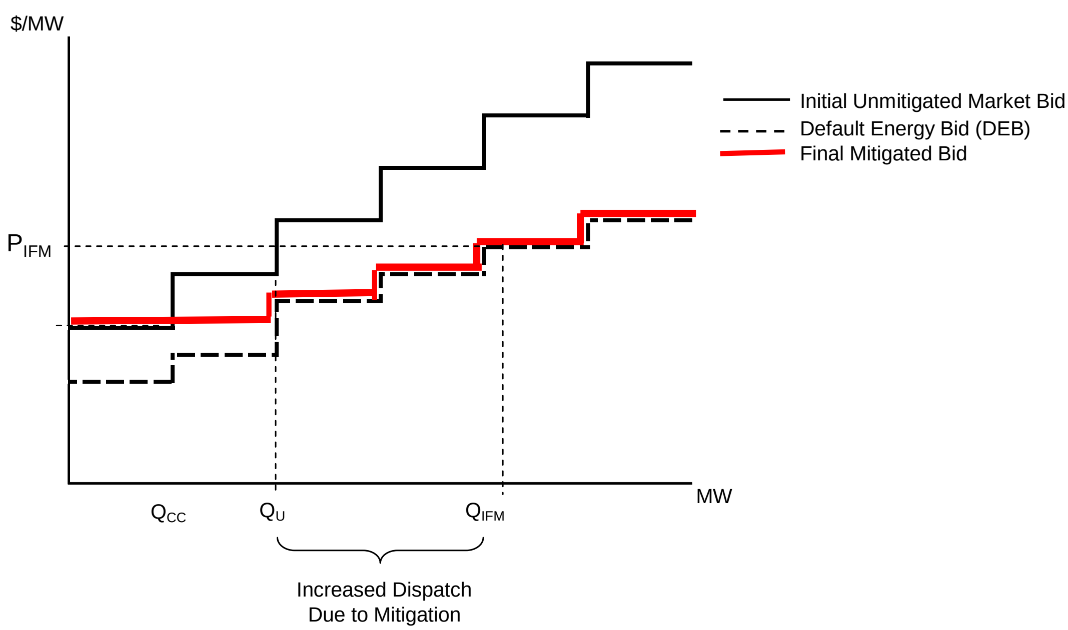


Figure A.2 Measuring Impact of Bid Mitigation



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 October, 2009.

/s/ Anna Pascuzzo

Anna Pascuzzo