California ISO
Your Link to Power

California Independent
System Operator Corporation

February 1, 2010

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 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 fourth quarter of 2009 (from October 1, 2009, through December 31, 2009) ("market services quarterly report"). Items for which the ISO's Department of Market Monitoring ("DMM") and the Market Surveillance Committee ("MSC") are responsible are addressed in this letter in sections II and III below.

As explained further below and in the attached report, the information in this transmittal letter complies 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."[3] The quarterly report also satisfies 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 *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 October 1 through December 31 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, and Exceptional Dispatch;
- The cost of the exemption for existing transmission contract rights;
- 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 October 1 through December 31 time period; and
- 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."[4] The ISO developed the evaluative criteria itemized above in consultation with stakeholders as directed by the September 2006 Order.[5] 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."[6] 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."[7] 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.[8]

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."[9] 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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4 *Id.*

5 *See id.*

6 *Id.*

7 *Id.*

8 "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.

9 *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."[10] 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."[11] 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."[12]

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."[13] 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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[10] *California Independent System Operator Corp.*, 126 FERC ¶ 61,081, at PP 4, 30, 41, 58 (2009).
[11] *California Independent System Operator Corp.*, 126 FERC ¶ 61,082, at P 39 (2009).
[12] ISO Compliance Filing, Docket No. ER09-241-000 (Mar. 2, 2009), Transmittal Letter at 5 n.6.
[13] *California Independent System Operator Corp.*, 126 FERC ¶ 61,147, at P 82 (2009).

II. Market Monitoring Issues

Mitigation Based on Bid-In Demand vs. ISO Forecast

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."[14]

As described in the previous two quarterly reports submitted by DMM, use of bid-in rather than forecast demand in the automated market power mitigation ("MPM") procedures that occur prior the running of the integrated forward market ("IFM"), could be expected to have a negligible impact on the level of mitigation in the IFM, and on final IFM schedules and prices. In the fourth quarter of 2009, the level of load scheduled in the IFM continued to be very high, with the load scheduled in the IFM typically equaling 95 to 100 percent of actual load. Under such conditions, 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.

DMM will continue to monitor this issue and report as appropriate. However, during the fourth quarter of 2009, the ISO's Board approved a Management proposal for convergence bidding under which the ISO will continue to retain its current pre-IFM MPM procedures based on forecast load when convergence bidding is implemented in 2011.

Frequently Mitigated Units

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."[15]

As described in the previous two quarterly reports submitted by DMM, the overall frequency with which units not under Resource Adequacy or Reliability Must Run contracts have been subject to mitigation under the ISO's MPM procedures has been relatively limited during 2009. This trend has continued with only two units with Frequently Mitigated Unit (FMU) status in the fourth quarter of 2009. One of these units was eligible for FMU status for all three months in this period, with one additional unit being eligible in December. DMM will include a more detailed update of this issue in its

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[14] *California Independent System Operator Corp.*, 119 FERC ¶ 61,076, at P 496 (2007).
[15] *California Independent System Operator Corp.*, 119 FERC ¶ 61,313, at P 352 (2007).

next quarterly report, based on a full 12 months of experience under the ISO's new market design.

III. Market Surveillance Committee

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 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.[16]

As noted in the ISO's report on the third quarter of 2009, the ISO's 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.[17] 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 has presented its analysis and results, and discussed issues relating to the Competitive Path Assessment methodology at the last two MSC meetings, on October 5, 2009 and January 22, 2010.[18] DMM stands ready to provide any other analysis or data the MSC may find useful in its assessment of the Competitive Path Assessment methodology. DMM anticipates that the MSC's assessment will be included in the quarterly report to be filed on April 30, 2010.

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16 September 2006 Order at P 1032.

17 *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.

Residual Supply Metrics: Methodology and Preliminary 2009 Results, Department of Market Monitoring, January 21, 2010. http://www.caiso.com/2725/2725e3899550.pdf

18 *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.

Competitive Path Assessment, presentation by Eric Hildebrandt, Dan Yang, and Ryan Kurlinski, Department of Market Monitoring, Market Surveillance Committee Meeting, January 22, 2010,. http://www.caiso.com/2725/2725e99139890.pdf

IV. Contents of Filing and Service

In addition to this transmittal letter, the instant filing includes Attachment A, the market services 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, this filing complies with the Commission's directives and the ISO's own commitments. Please contact the undersigned with any questions.

Respectfully submitted,

/s/ Sidney M. Davies

Sidney M. Davies
Assistant General Counsel
Anna A. McKenna
Senior Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400

Attachment A
Market Services Quarterly Report

California Independent
System Operator Corporation

California ISO

Post Implementation Report

February 1, 2010

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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

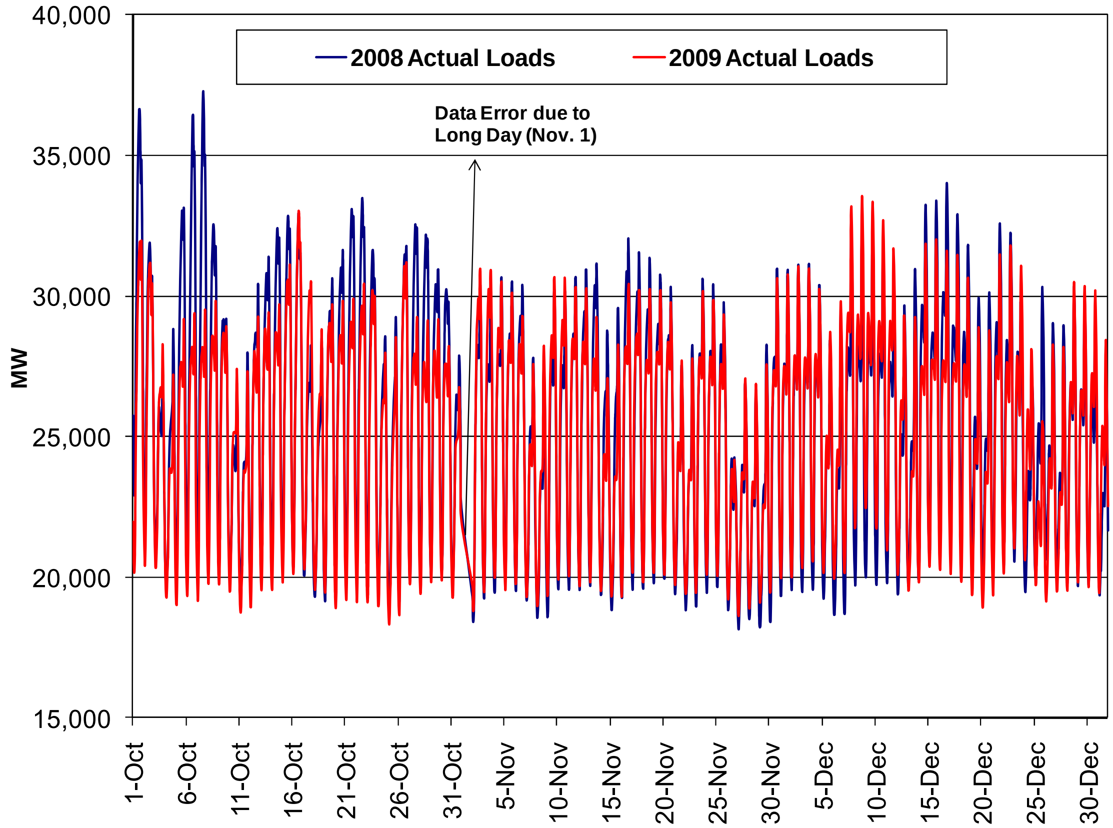
From October 1 to December 31, the demand was lower than last year for most days during the reporting period. Weak economy and relatively mild weather contributed to this. The first few days of December 2009 saw higher loads than December 2008 due to the cold spell. The loads never exceeded 34,000 MW during the reporting period. The load curves were showing the traditional winter pattern of a late evening peak, 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 residual unit commitment (RUC) procurement target and 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 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.

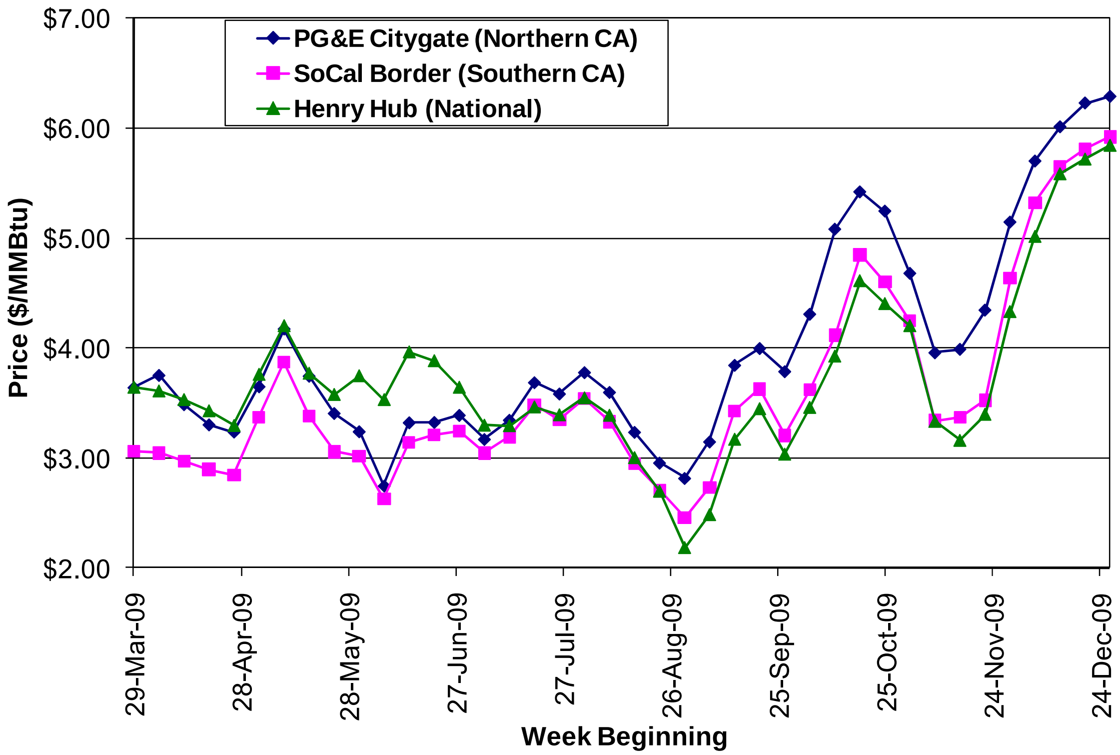
Figure 1: System Load Comparison –2009 vs. 2008



Natural Gas Prices and Inventories

Natural gas prices fell within the range of $3 /MMBTU to $6.3 /MMBTU from October 1 through December 31 in 2009. Natural gas prices increased significantly in the first three weeks of October due to cooler weather, rising crude oil prices, and injection demand for natural gas. Then natural gas prices declined from the week of October 25 until the middle of November. This can be attributed to warmer than normal temperatures, lower industrial demand, and ample production. From the week of November 15 through the end of December in 2009, natural gas prices rose again, mainly driven by cold weather and rising crude oil prices. The California Composite Average gas price increased approximately 68 percent to $5.94 per MMBtu on December 31 from $3.53 per MMBtu on October 1.

Figure 2: Weekly Average Natural Gas Spot Prices April 2009 to December 2009



Market Performance Metrics

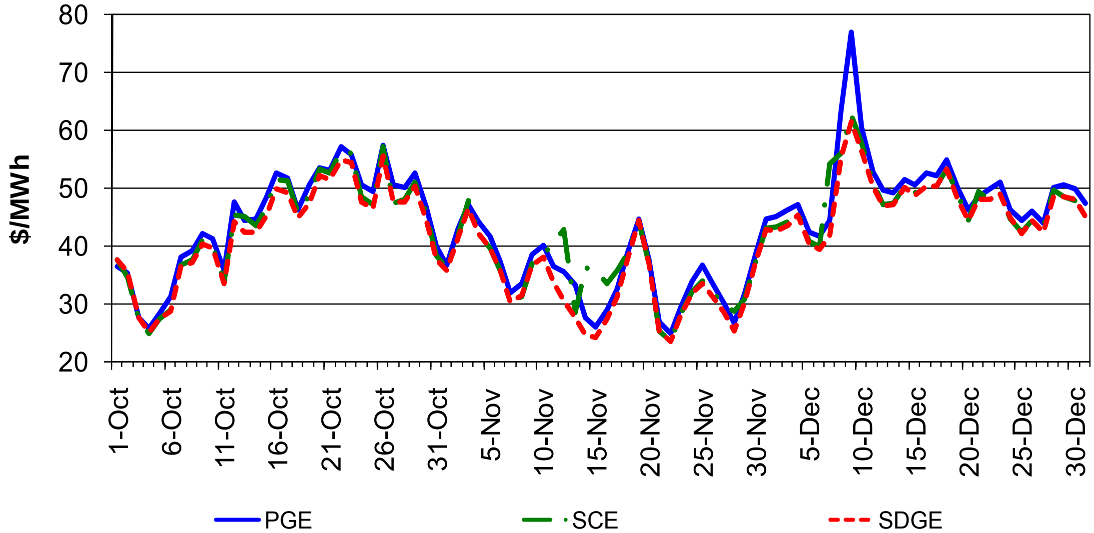
Energy

Day-Ahead Prices

Figure 3 on the next page shows the daily day-ahead load aggregation point (LAP) prices for the fourth quarter of 2009. The day-ahead energy prices on almost all days of the quarter were fairly stable, falling into the range of $23/MWh to $77/MWh. Prices in the three default LAPs for the quarter diverged on several days in November and December due to congestion on some transmission facilities. Starting on November 11, the ISO began enforcing the import limit that applies specifically to the SCE area (SCE_PCT_IMP branch group) in the market model, so that congestion related to this limit may be managed via the market optimization.[3] This branch group was congested from November 11 to November 17 and on December 7, elevating the energy prices in the SCE area. On November 12 and 13, congestion on Path 26 and Path 15 elevated the energy price in the PG&E LAP. These two branch groups were derated due to the scheduled outages of Midway-Vincent #3 and Los Banos-Midway #2 500 kV lines, respectively. On December 8 and 9 the Pacific Northwest experienced severe cold temperatures which drove up the demand for power in that region. To meet this demand scheduling coordinators were importing power from California, Nevada and Arizona, and as a result, the flows on the Pacific AC intertie (PACI) were in the south to north directions in both on-peak and off-peak hours. Usually in winter months flows on PACI intertie are in the north to south directions in on-peak hours and in south to north directions in off-peak hours. This unusual flow pattern and path capacity derates motivated by these planned outages caused congestion on the Los Banos North branch group. On average, this congestion elevated the energy price in the PG&E area by $7/MWh and $15/MWh on December 8 and 9, respectively. Consistent with the movement of the natural gas prices, the day-ahead market (DAM) saw increasing trends in energy prices during October and December, and a declining trend in November.

[3] For more details, please refer to the Technical Bulletin 2009-12-01 posted on the ISO website at http://www.caiso.com/2479/247997c52e0f0.pdf

Figure 3: Day-Ahead Weighted Average LAP Prices (All Hours)



Real-Time Prices

The daily real-time energy prices are shown in Figure 4 for the three default LAPs for the fourth quarter of 2009. In October and November, prices were more variable in the SCE and PG&E areas than in the SDG&E area, while in December, prices were more volatile in the SDG&E area. The divergence of prices among the 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 December. On December 7 and 8, the system tackled a myriad of transmission outages, which led the ISO to declare a grid warning notice. During this time there were also several generation units tripping offline. The inclement weather also made real-time load difficult to forecast and exceeded day-ahead schedules. Palo Verde was derated to reflect the forced outage of the North Gila-Hassayampa 500 kV line, reducing the imports into Southern California, which further aggravated conditions on the grid. All these conditions were reflected in multiple price spikes during this two-day period. On all the other days in the quarter, the daily average real-time energy prices for three default LAPs were between $15/MWh and $98/MWh.

Figure 4: Real-Time Weighted Average LAP Prices (All Hours)

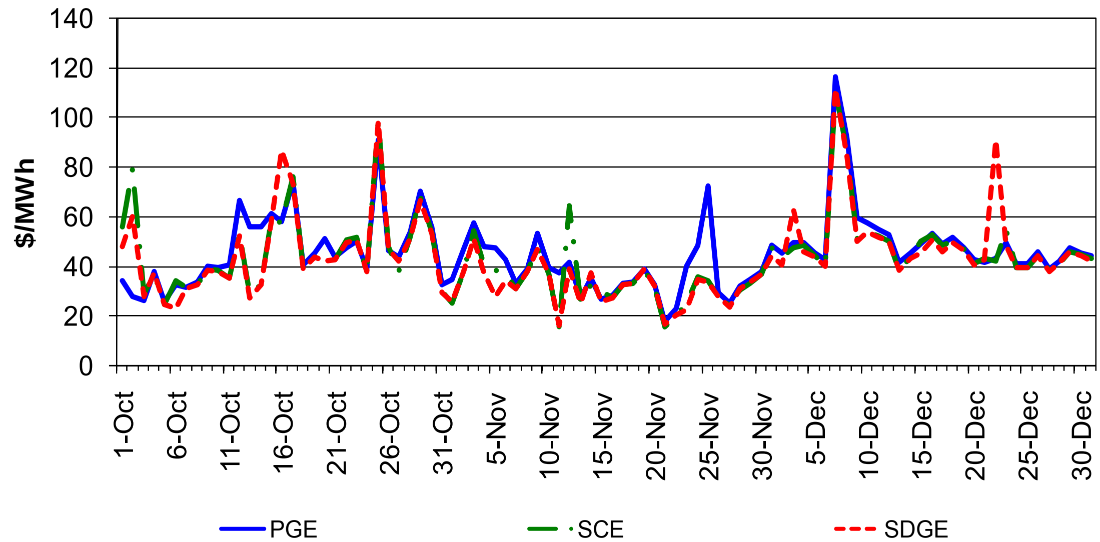


Figure 5 shows the daily frequency of price spikes by price range for the three default LAPs in the five-minute real-time dispatch (RTD) during the fourth quarter of 2009. In percentage terms, the frequencies of prices over $250/MWh were 1.24, 0.36 and 0.86 percent in October, November and December, respectively. As explained previously, the highest frequency of price spikes was observed on December 7 and 8. Prices exceeded $1000/MWh infrequently, with the most frequent occurrences of such prices in December at 0.03 percent, which increased from 0.004 percent of November and 0.008 percent of October. On December 22 prices exceeded $1000/MWh when the SDGE_CFE import branch group experienced congestion. The ISO operators adjusted this branch group limit to preserve its reliability margin, which was further affected by the loss of 200 MW of generation when a unit tripped off line.

Figure 5: Daily Frequency of RTD LAP Positive Price Spikes

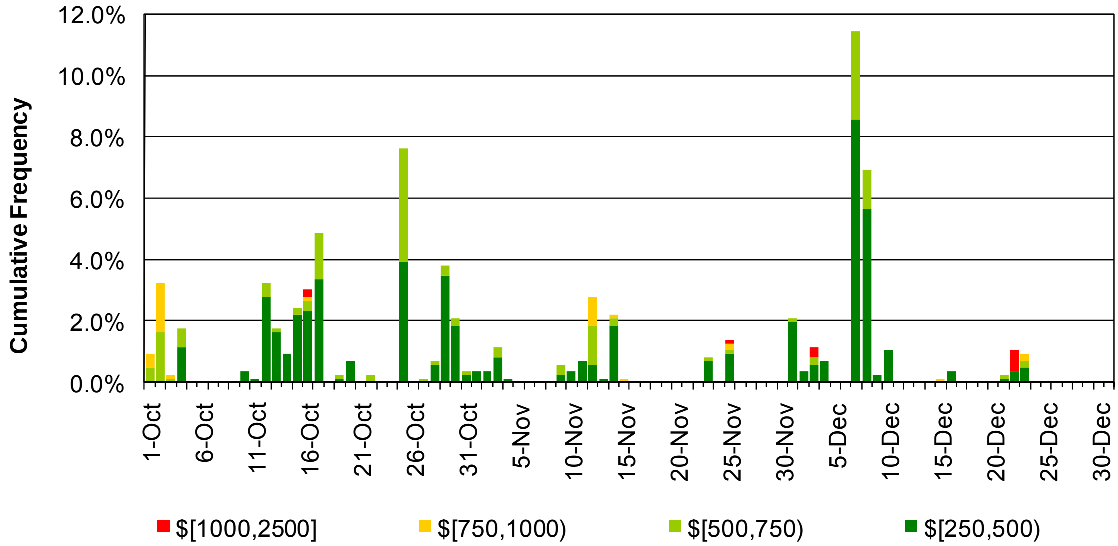
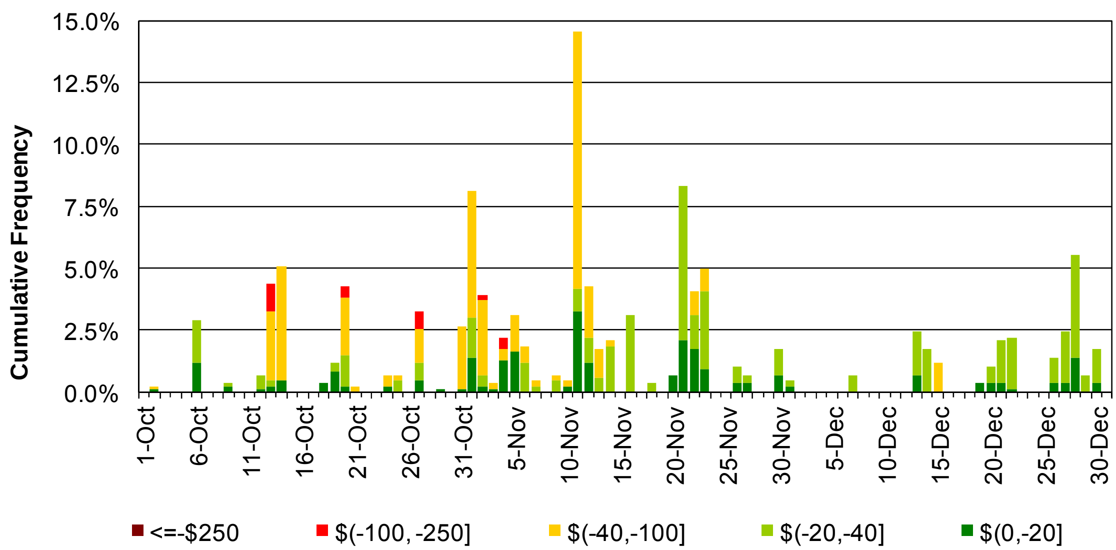


Figure 6 shows the daily frequency of negative prices by price range for all three default LAPs in the five-minute real-time market. The frequency of negative prices declined to 0.77 percent in December from 2.29 percent of November and 0.82 of October. Negative prices in October and November were mainly observed as a result of congestion on either Path 26 or Los Banos North branch groups, which created price separations. During December, however, negative prices were mainly driven by overgeneration conditions.

Figure 6: Daily Frequency of RTD LAP Negative Price Spikes

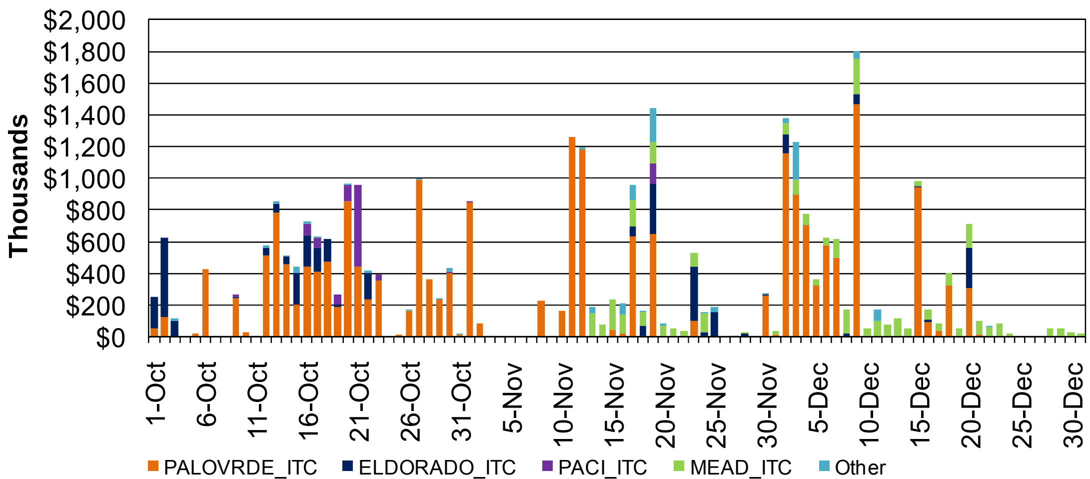


Congestion

Congestion Rents on Interties

Figure 7 below illustrates the daily total integrated forward market (IFM) congestion rents by intertie for the fourth quarter of 2009, while Table 1 provides a breakdown of the average volume (MW) cleared in the integrated forward market, the average shadow price ($/MWh), and the number of congested hours by intertie. The cumulative congestion rent on interties for the fourth quarter was $30 million, higher than $17.4 million in the third quarter. The ISO calculates congestion rents for each intertie as the product of the shadow price and the flow limit of the intertie. Of the total, the vast majority of rents occurred on three interties: Palo Verde (71 percent), El Dorado (11 percent) and Mead (11 percent).

Figure 7: IFM Congestion Rents by Intertie (Import)



The Palo Verde intertie was congested on almost all days during the latter half of October. The majority of congestion rents on the El Dorado intertie in October occurred during the third week, mainly driven by a combination of scheduled and forced outages.

In November, the average shadow price on Palo Verde Intertie was $14/MWh which was slightly higher than $10/MWh in October. In December the average shadow price on Palo Verde intertie was $19/MWh, which was slightly higher than $14/MWh in November. More than 75 percent of the total congestion rent on Palo Verde occurred during the first 10 days of the month, mostly due to path capacity derates driven by both planned and forced outages. The planned outage of the Serrano-Valley 500 kV line from November 30 till December 7 reduced capacity on Palo Verde intertie by 500 MW. On December 9, the Palo

Verde intertie capacity was reduced to half of its nominal value due to a forced outage of the North Gila – Hassayampa 500 kV line.

Table 1: IFM Congestion Statistics by Inter-Tie (Import) [4]

Inter-Tie	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
BLYTHE_ITC	Oct-2009	189	14.30	18
COTPISO_ITC	Oct-2009	23	58.72	16
ELDORADO_ITC	Oct-2009	1,217	7.39	200
IID-SCE_ITC	Oct-2009	586	3.72	13
NOB_ITC	Oct-2009	228	18.25	10
PACI_ITC	Oct-2009	2,223	5.45	73
PALOVRDE_ITC	Oct-2009	2,663	9.56	351
PARKER_ITC	Oct-2009	180	23.99	16
SUMMIT_ITC	Oct-2009	7	37.74	66
ADLANTO-SP_ITC	Nov-2009	1,158	4.79	34
BLYTHE_ITC	Nov-2009	73	70.35	23
ELDORADO_ITC	Nov-2009	1,189	9.74	86
IID-SCE_ITC	Nov-2009	586	1.56	1
MEAD_ITC	Nov-2009	994	7.72	173
MERCHANT_ITC	Nov-2009	797	5.00	51
NOB_ITC	Nov-2009	568	4.35	42
PACI_ITC	Nov-2009	1,893	6.38	11
PALOVRDE_ITC	Nov-2009	2,551	14.12	157
ADLANTO-SP_ITC	Dec-2009	1,124	9.85	20

[4] On trade date November 13, 2009, the California ISO implemented refinements to constraints in the (SPTO) area covered by ISO Operating Procedure S-326. These refinements will better align the scheduling limits and how they apply to simultaneous schedules of energy, ancillary service, converted rights (CVR), existing transmission contract (ETC) rights, and transmission ownership rights (TOR). The refinements are:

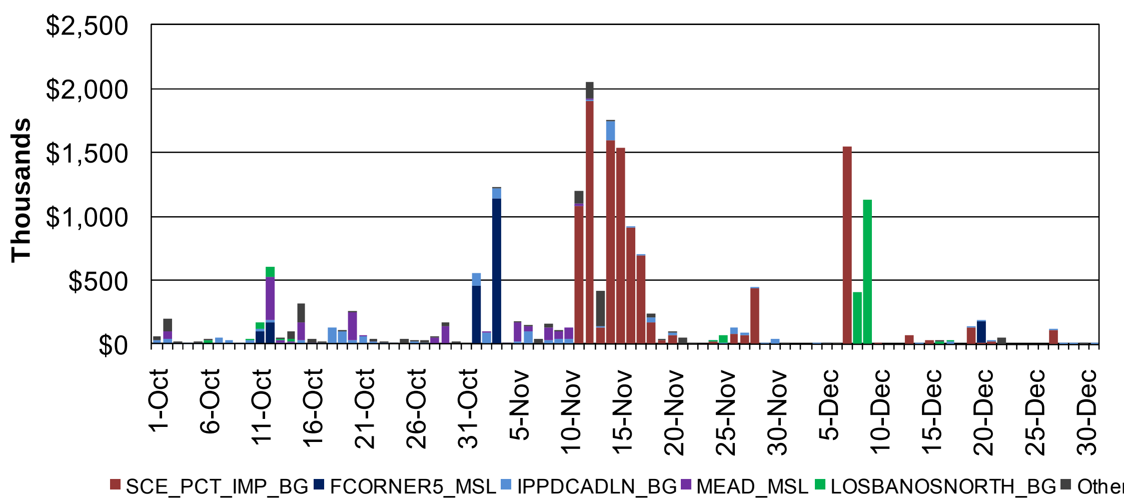
1. Create a new MEAD_ITC as a companion to the combination of MEAD_MSL and MEADTMEAD_MSL. Includes schedules for the following scheduling points MEAD230 and MEAD2MSCHD.
2. Create a new SYLMAR-AC_ITC as a companion to the SYLMAR-AC_MSL. Includes schedules for the SYLMAR-AC scheduling point.
3. Create a new VICTVL_ITC as a companion to the VICTVL_MSL. Includes schedules for the Victorville scheduling point
4. Create a new ADLANTO-SP_ITC as a companion to the ADLANTO-SP_MSL. Includes all remaining schedules previously assigned to ADLANTOVICTVL-SP_ITC excluding the schedules re-assigned to VICTVL_ITC, SYLMAR-AC_ITC and MEAD_ITC.
5. Eliminate ADLANTOVICTVL-SP_ITC which was the companion to the ADLANTOVICTVL-SP_MSL. ADLANTOVICTVL-SP_MSL will remain as energy scheduling limit constraint.

BLYTHE_ITC	Dec-2009	189	4.41	8
ELDORADO_ITC	Dec-2009	1,113	9.16	56
IID-SCE_ITC	Dec-2009	586	6.24	13
MEAD_ITC	Dec-2009	901	8.15	298
PALOVRDE_ITC	Dec-2009	2,252	18.55	198
PARKER_ITC	Dec-2009	179	18.43	35

Congestion Rents on Branch Groups and Market Scheduling Limits

Figure 8 illustrates daily total congestion rents on branch groups and market scheduling limits (MSL) collected in the integrated forward market, while Table 2 provides a breakdown of the average volumes of transmission interface capacity cleared in the integrated forward market, the average shadow price ($/MWh), and the number of congested hours by branch group for the fourth quarter of 2009. The daily total congestion rents are the sum of hourly congestion rents for all trading hours. The hourly congestion rents are calculated as the product of shadow price and the flow limit. For the fourth quarter of 2009, the total branch group and market scheduling limit congestion rent was $19 million up from $7.4 million in the third quarter. The vast majority of branch group and market scheduling limit congestion rents occurred on Southern California Edison Percent Import (56 percent), Four Corners (11 percent), Los Banos North (10 percent), Inter Mountain DC- Adelanto (9 percent) and Mead MSL (9 percent).

Figure 8: IFM Congestion Rents by Branch Group



The cumulative congestion rents on branch groups and market scheduling limits was $2.67 million in October, which is 14 percent of the total congestion rent in the fourth quarter. In October most of the congestion rents occurred on Mead MSL and Inter Mountain DC- Adelanto branch group.

On November 11, the ISO began enforcing the SCE_PCT_IMP branch group. This limit ensures that SCE imports do not exceed 60 percent of its load.[5] Since April 1 through October 22, system conditions were such that the SCE import limit was not exceeded. Therefore, no actions were necessary to ensure that the limit was honored. However, as of October 22, conditions were such that it was necessary to perform an increased level of exceptional dispatch to maintain the real-time imports within the limit. As of November 11, the ISO began enforcing the import limit in the market so that the ISO congestion related to this limit was managed through the market optimization. Congestion rents on SCE_PCT_IMP branch group for November were $7.4 million and were collected mainly in the period November 11 through November 17, when the limit was new for the market. However, after this period congestion on this branch group diminished as the market adjusted to internalize and account for its impact. Congestion rents on Four Corners market scheduling limit accrued on November 1 and 3 when its limit was derated about 50 percent to reflect the outage of the Four Corners 1AA bank.

Out of the total congestion rents on the SCE_PCT_IMP branch group in December, more than 80 percent of rents occurred on December 7. The SCE_PCT_IMP branch group constraint enforces a limit on the total imports permitted into the Southern California Edison (SCE) area. On December 7, few units in the SCE area were out-of-service and the SCE area load had to import more supply. This increased requirements for imports resulted in congestion rents on the SCE_PCT_IMP branch group. About 98 percent of the total congestion rents on Los Banos north branch group occurred on December 8 and 9. On December 8, the Los Banos North branch group was binding in the day-ahead market due to the scheduled outages of Moss Landing - Los Banos 500 kV line and the Los Banos-Midway #2 500 kV line, and then on December 9 it was binding due to the outage of Los Banos-Gates #3 500 kV line.

[5] For more details, please refer to the Technical Bulletin 2009-12-01 posted on the ISO website at http://www.caiso.com/2479/247997c52e0f0.pdf

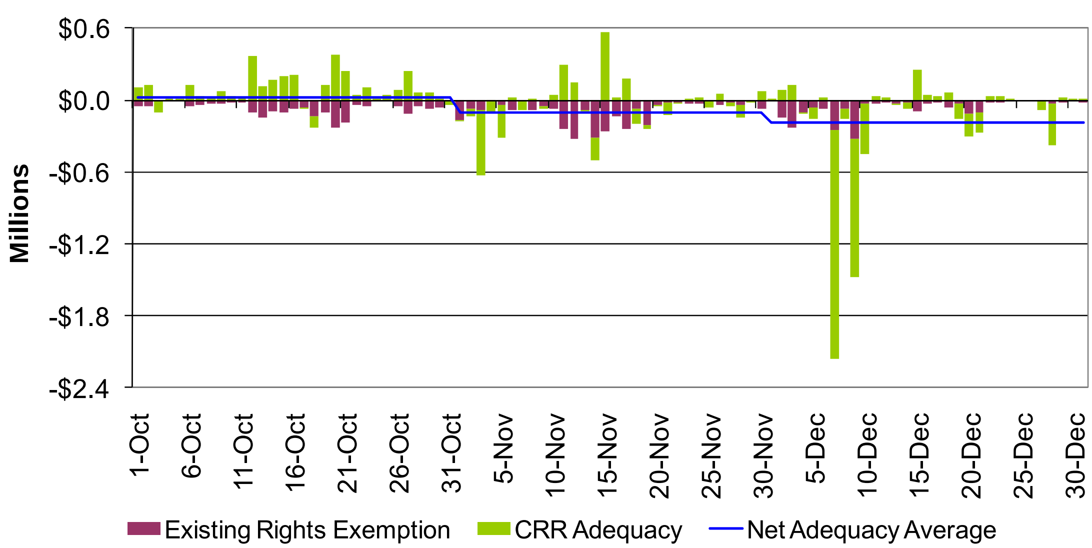
Table 2: IFM Congestion Statistics by Branch Group

Branch Group	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
ADLANTOSP_MSL	Oct-2009	1,217	3	24
FCORNER5_MSL	Oct-2009	840	17	19
IPPDCADLN_BG	Oct-2009	647	4	261
IVALLYBANK_XFBG	Oct-2009	900	3	16
LOSBANOSNORTH_BG	Oct-2009	1,216	7	23
LUGO_VINCENT_BG	Oct-2009	3,090	3	10
MEAD_MSL	Oct-2009	1,460	7	94
MIGUEL_IMP_BG	Oct-2009	1,900	6	9
MKTPCADLN_MSL	Oct-2009	556	5	26
PATH26_BG	Oct-2009	853	4	33
SDGEIMP_BG	Oct-2009	2,109	3	5
VICTVL_BG	Oct-2009	2,640	1	1
WSTWGMEAD_MSL	Oct-2009	127	14	3
ADLANTOSP_MSL	Nov-2009	1,217	2	14
FCORNER5_MSL	Nov-2009	800	49	41
HUMBOLDT_BG	Nov-2009	43	93	27
IPPDCADLN_BG	Nov-2009	644	5	303
LOSBANOSNORTH_BG	Nov-2009	1,720	5	9
MEAD_MSL	Nov-2009	1,460	6	55
MKTPCADLN_MSL	Nov-2009	605	5	29
PATH15_BG	Nov-2009	3,488	4	24
PATH26_BG	Nov-2009	1,002	3	30
SCE_PCT_IMP_BG	Nov-2009	6,731	11	120
SDGEIMP_BG	Nov-2009	1,150	3	2
WSTWGMEAD_MSL	Nov-2009	171	4	25
FCORNER5_MSL	Dec-2009	840	22	9
HUMBOLDT_BG	Dec-2009	43	34	2
IPP-IPPGEN_MSL	Dec-2009	470	8	2
IPPDCADLN_BG	Dec-2009	647	2	63
LOSBANOSNORTH_BG	Dec-2009	2,499	21	31
MKTPCADLN_MSL	Dec-2009	605	8	10
SCE_PCT_IMP_BG	Dec-2009	6,016	10	33
WSTWGMEAD_MSL	Dec-2009	183	3	3

Congestion Revenue Rights[6]

Figure 9 illustrates the revenue adequacy for congestion revenue rights (CRRs) for the fourth quarter of 2009. Revenue adequacy for congestion revenue rights reflects the extent to which the hourly net congestion revenues collected from the integrated forward market are sufficient to cover the hourly net payments to congestion revenue right holders. A net positive value indicates that there is a surplus and a net negative value indicates there is a shortfall. Furthermore, the congestion rents available from the integrated forward market to fund the CRR payments is lessened by the requirement that holders of existing rights (transmission ownership rights (TOR), existing transmission contracts (ETC) and Converted Rights (CVR)) are completely exempt from congestion charges. This requirement is contractual and is written into the ISO tariff. The ISO respects this requirement and enforces it by immediately reversing any and all congestion charges that are levied on these rights holders. As the congestion reversal monies are extracted from the pool of revenues available from the integrated forward market, the ISO models the expected usage of the transmission system by the existing rights holders and sets aside the capacity that it expects will be used. This modeling method is internal to the ISO and the payment to the rights holders is always honored regardless of the accuracy of the ISO's efforts to put aside the expected amount of rights that will be used. The ISO explicitly tracks the costs of this exemption, as shown in purple bars in Figure 9.

Figure 9: Daily Revenue Adequacy of Congestion Revenue Rights



[6] The metrics presented in this section and also in the sections of Post-Day-Ahead Existing Rights Exemption and Cost of the Existing Rights Exemption are based on preliminary settlements data. For the month of October, the metrics are based on T+38B data, while for the month of November and December the metrics are based on T+7B data.

Both the hourly revenue adequacy amounts (net congestion revenues less net payments to CRR holders, as reflected in the green bars in Figure 9) and the congestion credit for the existing rights exemption (in purple bars) 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 9. 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 in accordance with the ISO tariff. Thus, in accordance with the principle of full funding of CRRs, any deficit in the congestion revenue right balancing account at the end of a month does not adversely affect the payments to CRR holders. In Figure 9, the cost of the existing rights exemption 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 9 shows the monthly average of the daily net revenue adequacy, which includes the impact of both the CRRs payments and the cost of the existing rights exemption on revenue deficiency. As shown in Figure 9, the daily average of revenue surplus has been $27,216 in October, and turned into a deficit of $104,400 and $185,500 in November and December, respectively.

There were 16, 26, and 10 days in which revenue deficiencies were observed in October, November, and December, respectively. The most significant deficiencies in November were on the 3rd, 5th, 14th and 19th. Throughout the month, the Palo Verde intertie was slightly derated to reflect the outage of a transmission element of the Navajo-Crystal 500 kV line. In addition, Palo Verde was further derated on November 2 through 5 and on November 17, 19, 21 and 30 to accommodates other outages. Also, in the first several days of November, the Four Corners market scheduling limit was derated by 50 percent to reflect the outage of the Four Corners 1AA bank. This resulted in collecting congestion revenues on less transmission capacity in comparison to the transmission capacity release as CRRs, and drove the high deficiency on November 3.

The most significant deficiencies in December were observed on the 7th and 9th. On December 7, the Palo Verde intertie was derated to about 2794 MW to reflect outages; there were also outages of transmission lines that drove congestion on a nomogram and on two other transmission lines. The derate on Palo Verde also drove deficiencies in the first week of December and together with other outages represented less transmission capacity available in the energy market in comparison to the transmission capacity release through CRRs, which had these elements at nominal values in the congestion revenue right model. Furthermore, the SCE_PCT_IMP branch group, which as discussed above the ISO has begun enforcing through its energy market, was binding on this day as well. With a forward-looking timeframe for releasing congestion revenue rights, however, this same constraint had not been enforced in the release of congestion revenue rights for December. Not enforcing this branch group in the CRR markets that ultimate is enforced in the day-ahead market may or may not result in revenue deficiencies, but enforcing it in the CRR market eliminates a systematic gap that exposes the market to revenue deficiencies. In the case of December 7, the enforcement of the SCE_PCT_IMP contributed to revenue deficiencies as well. The derate of the Palo Verde intertie on December 9 to 1440 MW due to the forced outage of the North Gila-Hassayampa line caused the shortfalls observed on that day. On this day, the Los Banos North was also congested and was also derated to reflect the outage of the Los Banos-Midway # 2 line. More deficiencies were observed on i) December 19 due to the binding of the SCE_PCT_IMP branch group; ii) December 20 due to a derate on Palo Verde to about 2700 MW, compounded with the heavy derate on Four Corners to 840 MW; and iii) December 28 due to outages of two transmission lines that affected congestion on the La Fresa-Hinson line.

During the fourth quarter, the ISO used two adjustments in its monthly CRR release processes aiming to attain revenue adequacy on a monthly basis using only the congestion revenues from the integrated forward market, including the effects of the existing rights exemption, and without relying on the CRR auction revenues.

1. Modeling of outages in the monthly CRR release processes.

A critical element of the ISO's monthly CRR release process to ensure revenue adequacy 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 a 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 November and December, this derating factor was insufficient to ensure revenue neutrality.

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 existing rights exemption. The revenue adequacy ratio is the ratio of the money collected from the integrated forward market to the money paid to both the CRR entitlements and the existing rights exemption. 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, the monthly net balance allocated to measured demand was negative for the months of November and December. 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 integrated forward market should be sufficient to cover both the CRR payments and the cost of the existing rights exemption over the course of each month, so that the auction revenues can be returned fully to measured demand.

Table 3: Summary of Monthly Revenue Adequacy

	OCTOBER	NOVEMBER	DECEMBER
Congestion Rents	$15,834,828.93	$21,985,786.32	$16,394,070.53
CRR Payments	$13,000,562.26	$22,283,280.84	$20,192,919.76
CRR Adequacy	$2,834,266.67	-$297,494.52	-$3,798,849.22
Existing Rights Exemptions	-$1,990,553.19	-$2,834,484.86	-$1,951,605.18
Net Adequacy	$843,713.5	-$3,131,979.4	-$5,750,454.4
Adequacy Ratio	105.63%	87.53%	74.03%
Auction Revenues	$1,637,554.0	$2,130,795.0	$3,196,312.3
Monthly Net Balance	$2,481,267.5	-$1,001,184.4	-$2,554,142.2

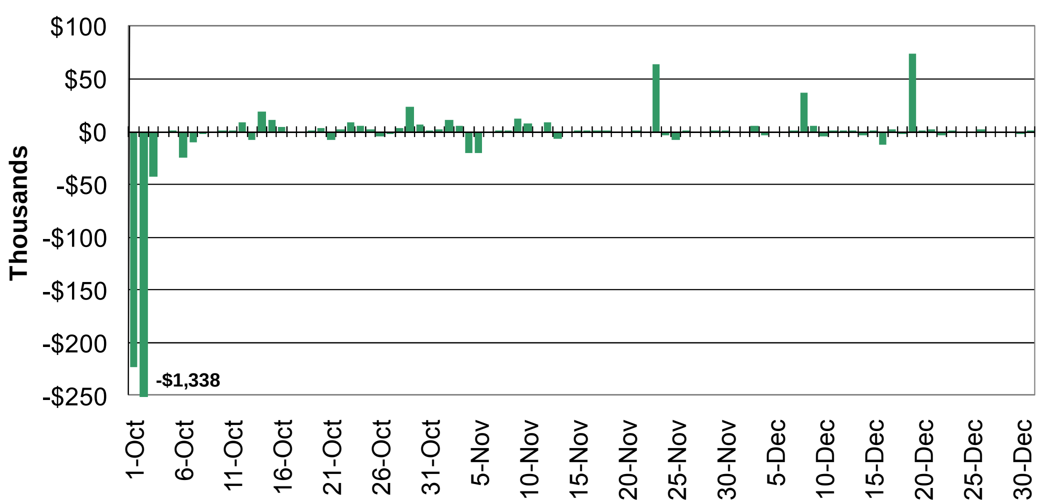
Unlike the month of October in which there was a CRR revenue surplus, auction revenues were used to offset the revenue deficiencies of November and December. For October, there was indeed a surplus from CRR entitlements that was added to the auction revenues that the ISO distributed to measured demand. In contrast, there was a net revenue deficiency of $1 and$2.5 million, in November and December, respectively, that the ISO will allocate to measured demand. Through the quarter, the revenue adequacy ratio declined from 105.63 percent to 74 percent. Auction revenues consistently increased during the fourth quarter, due mostly to higher contributions from the monthly auctions.

Post-Day-Ahead Existing Rights Exemption

Similar to the day-ahead market, the ISO collects real-time market 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 existing rights may utilize their rights to submit post-day-ahead, (i.e., in the hour-ahead scheduling process or real-time dispatch period) schedule changes with respect to their accepted day-ahead self-schedules.[7] 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 markets, and in the real-time is independent of any settlement of the day-ahead. The remaining real-time market congestion rents –surplus or deficit– are allocated to measured demand excluding measured demand associated with valid and balanced portions of existing rights. The real-time congestion rents and the existing rights exemption costs do not impact the settlements of congestion revenue rights, and 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 10 shows the daily net cost for honoring the existing rights exemption of post-day-ahead schedule changes of existing rights. A negative value of the existing rights exemption indicates a net payment from the ISO to existing right holders to reverse the post-day-ahead congestion charge, i.e., a credit. A positive value of the existing rights exemption indicates a net charge to existing right holders to reverse the post-day-ahead congestion payment.

Figure 10: Cost of the Existing Rights Exemption for Post-Day-Ahead ETCs/TORs



[7] Converted rights are only eligible for the existing rights exemption in association with accepted self-schedules in the integrated forward market.

The extent of the cost of the existing rights exemption for post-day-ahead schedule changes for existing rights 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 10, the cost of the existing rights exemption for post-day-ahead transactions was relatively low with the exception of two days in October, due mainly to higher congestion experienced in the real-time market.

Ancillary Service Markets

Integrated Forward Market (Day-Ahead) Average Prices

Table 4 shows the daily day-ahead average ancillary service procurements and prices for the fourth quarter of 2009, and Figure 11 on the next page shows the daily integrated forward market 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 average regulation up procurement quantity[8] increased steadily from 353 MW in October to 371 MW in December, whereas hourly average procurement of regulation down was around 350 MW in all three months of the quarter. Both spinning and non-spinning reserves hourly average procurement quantity increased from about 770 MW in October to about 800 MW in December with a slight decrease in November to about 750 MW.

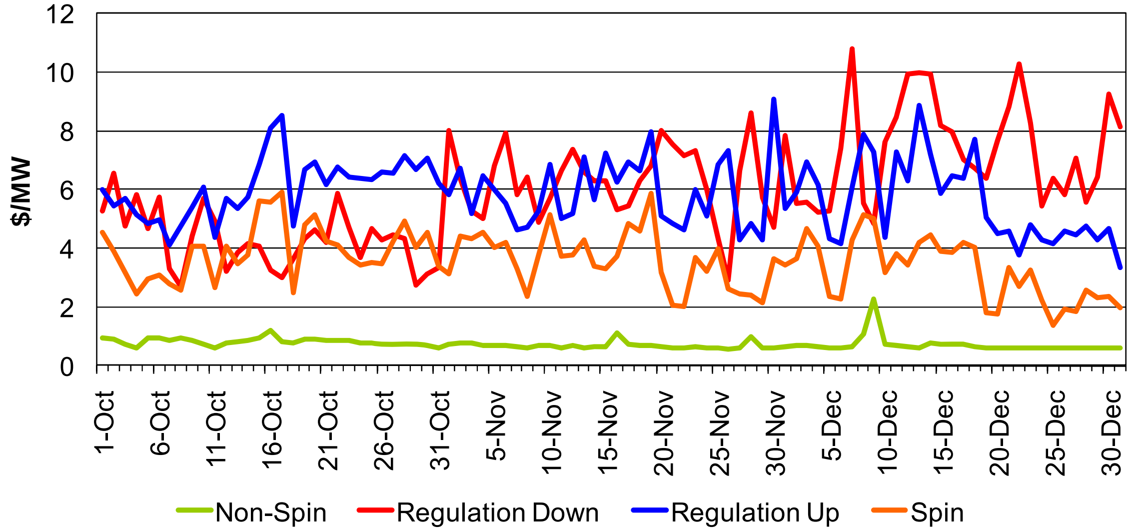
Table 4: IFM (Day-Ahead) Average Ancillary Service Procurement and Price

	Average Procured				Average Price			
	Reg Up	Reg Dn	Spin	Non Spin	Reg Up ($/MW)	Reg Dn ($/MW)	Spin ($/MW)	Non-Spin ($/MW)
Oct-09	353	351	771	772	6.06	4.31	3.89	0.81
Nov-09	357	347	746	751	5.92	6.28	3.60	0.68
Dec-09	371	355	802	806	5.54	7.40	3.21	0.70

[8] Beginning October 3rd, 2009, the ISO began to vary its regulation requirements by hour. More information is available from a Technical Bulletin http://www.caiso.com/2494/2494c16876b0.pdf

The hourly average price for regulation down increased steadily from $4.31/MW in October to $7.4/MW in December. The average price for the fourth quarter for regulation up, spinning and non-spinning reserves was $5.84/MW, $3.57/MW and $0.73/MW, respectively.

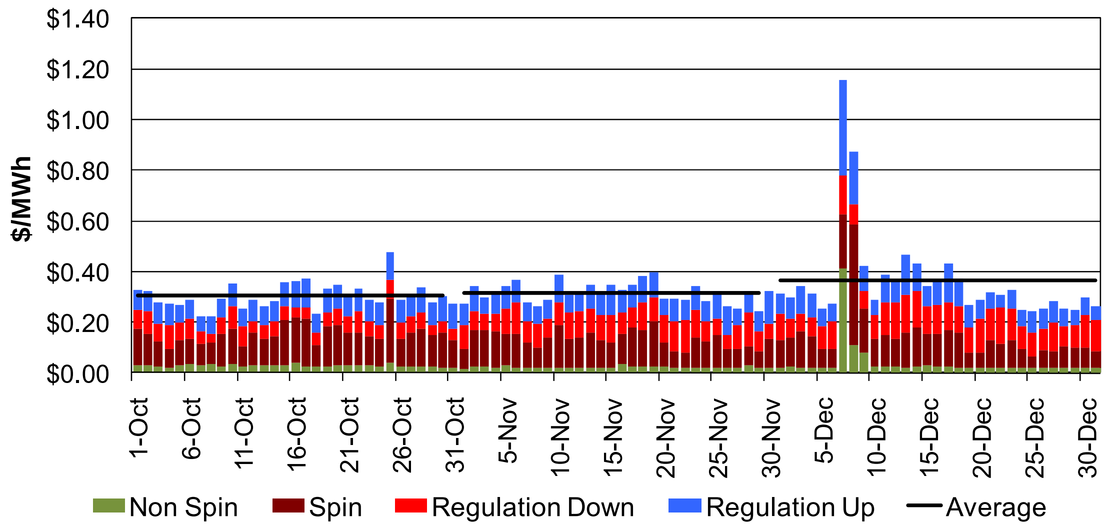
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Services Cost to Load

Figure 12 below shows the total system (day-ahead and real-time) average cost to load for ancillary services procured for the fourth quarter of 2009. The average cost to 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 increased during the third quarter from $0.30/MWh in October to $0.36/MWh in December. December 7 and 8 saw a higher ancillary services cost to load due to the increase in opportunity cost to provide ancillary services in the real-time market. The increase in opportunity cost was driven by increases in the real-time energy price, which were explained in real-time pricing section of this report.

Figure 12: System (Day-Ahead and Real-Time) Average Cost to Load



Residual Unit Commitment

The residual unit commitment (RUC) process is a reliability run that occurs after the integrated forward market. The residual unit commitment process differs from the integrated forward market primarily in that it runs against the ISO forecast of internal ISO demand rather than bid-in demand. The purpose of this section is to show how often the residual unit commitment process backstops the integrated forward market and the resulting costs. Residual unit commitment capacity is the positive difference between the residual unit commitment schedule and the greater of the integrated forward market schedule and the minimum load level of a resource. The residual unit commitment award is the portion of residual unit commitment capacity in excess of reliability must-run (RMR) capacity or the resource adequacy obligation. All residual unit commitment awards are paid the residual unit commitment LMP. Resource adequacy and RMR units do not receive the additional payment for their residual unit commitment capacity because they are already compensated through their contracts.

Figure 13 presents daily resource adequacy or RMR type residual unit commitment capacity and awards for the fourth quarter of 2009. Approximately 99.04 percent of residual unit commitment capacity was procured from resource adequacy or RMR units in the quarter. The monthly average procured residual unit commitment capacity declined gradually, from 436 MW in October, to 371 MW in November, and then to 301 MW in December.

Figure 13: RA/RMR RUC Capacity vs. RUC Award (All Hours)

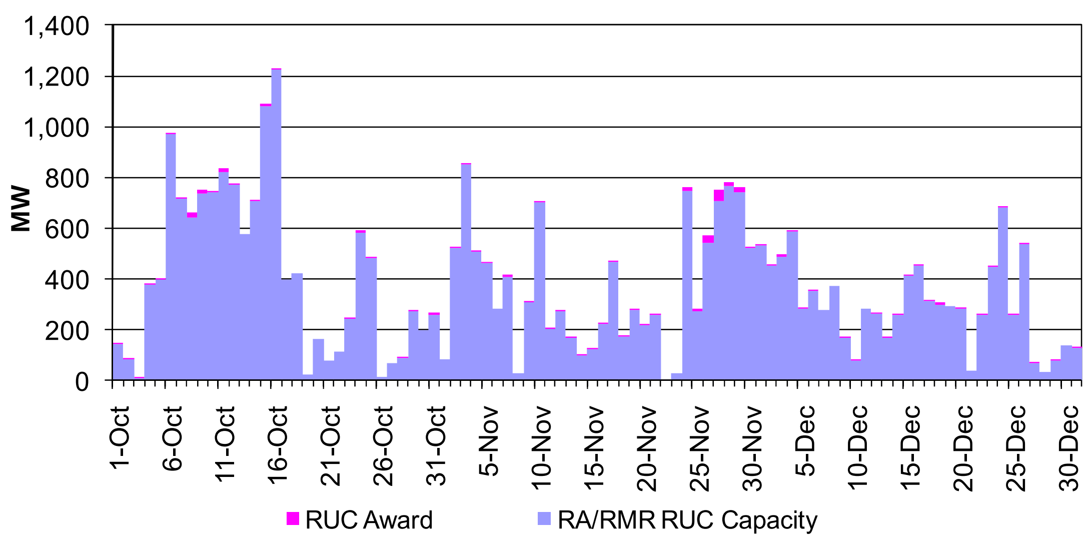
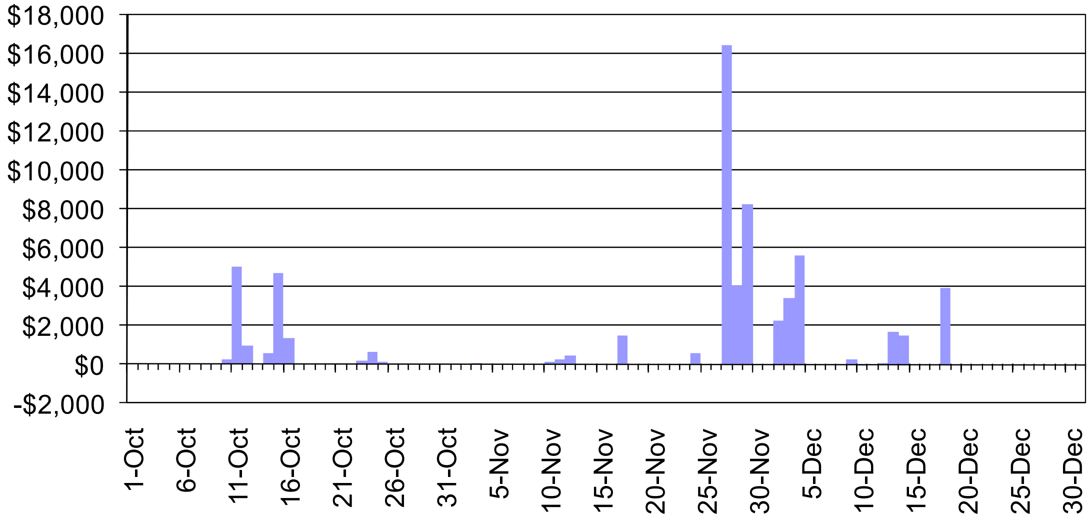


Figure 14 shows the daily cost of residual unit commitment procurement for each trading day for the fourth quarter of 2009. The monthly residual unit commitment procurement costs were $13,893, $31,590 and $18,703 in October, November and December, respectively. About 44.77 percent of the residual unit commitment cost for the quarter occurred on three days, November 27 to November 29, while G-217 was binding, elevating the residual unit commitment LMPs in that zone.

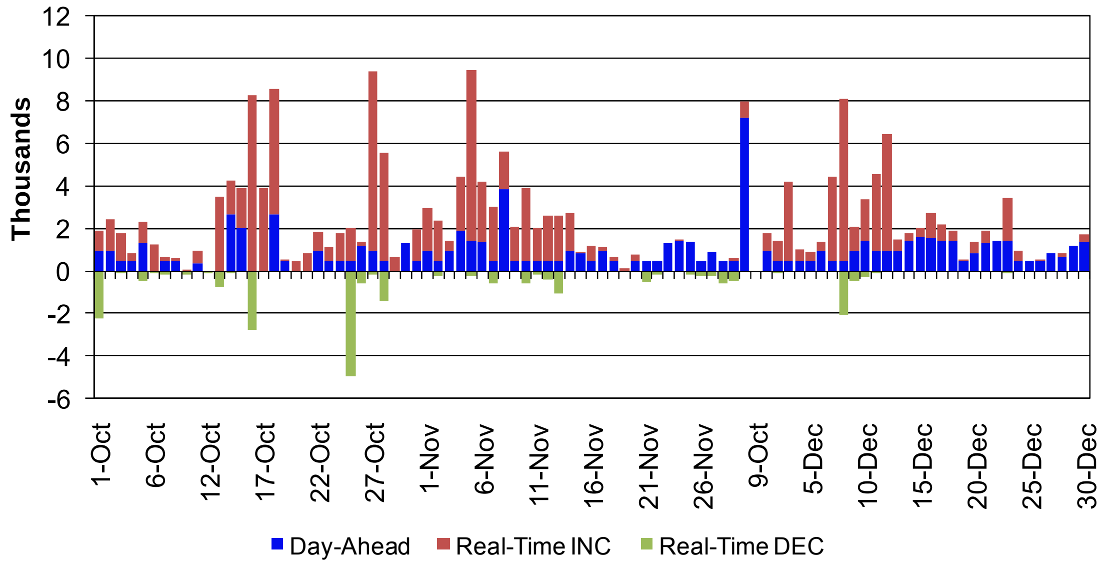
Figure 14: Total RUC Cost



Exceptional Dispatch

Figure 15 identifies instances of Exceptional Dispatches broken out by type of dispatch for the reporting period October 1 through December 31.[9] The total volume of exceptional dispatch in the fourth quarter of 2009 was 206,000 MWh. The month of October, November and December contributed 37 percent, 29 percent and 35 percent, respectively, to the quarterly total.

Figure 15: Total Exceptional Dispatch Volume (MWh) by Market Type



9 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

Cost of the Existing Rights Exemption[10]

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 existing rights exemption costs. The percentage shown is the ratio of the existing rights exemption to the congestion rents. Table 5 reflects the cost charged to demand not holding existing rights to honor the existing rights exemption 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 Existing Rights Exemption

	DA Market			RT Market		
Month	Congestion Rents	Existing Rights Exemption	Cost Percentage	Congestion Rents	Existing Rights Exemption	Cost Percentage
OCTOBER	$15,834,828.93	-$1,990,553.19	-12.57%	-$5,701,752.40	-$1,560,110.91	27.36%
NOVEMBER	$21,985,786.32	-$2,834,484.86	-12.89%	-$2,848,524.69	$53,561.98	-1.88%
DECEMBER	$16,394,070.53	-$1,951,605.18	-11.90%	-$2,581,657.32	$100,603.68	-3.90%
Total	$54,214,685.78	-$6,776,643.22	-12.50%	-$11,131,934.40	-$1,405,945.25	12.63%

The cost of the existing rights exemption to load not under an existing right in the day ahead market during the fourth quarter was $6.77 million, which represents 12.5 percent of the congestion rents collected in the integrated forward market, up from the 9.26 percent of the third quarter. As detailed in the congestion revenue right section above, in each month of the quarter, the existing rights exemption requirements reduced the available funds from the congestion revenues of the integrated forward market, which in turn affected the CRR revenue adequacy. Compared to the integrated forward market costs, the cost of the existing rights exemption in the real-time market was lower, about $1.4 million, with most of that cost collected in October. The post day-ahead cost of the existing rights exemption amounts to about the same percentage of the day-ahead cost, at 12.6 percent of the total congestion cost for this quarter, up from the 3.93 percent observed in the third quarter. Congestion revenues in the real-time market were a negative balance (deficit) and were allocated to non-ETC/TOR measured demand. The existing rights exemption in October was a payment to holders of rights, resulting in an additional cost to non-ETC/TOR loads that are allocated the net negative congestion rents. The cost of the existing rights exemption in November and December, in contrast, was a charge to holders of existing rights and, thus, helped reduce the negative congestions rents in these months.

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[10] 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 existing rights and charged to non-existing-rights 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 fourth quarter of 2009.

Reliability – Compliance with NERC Reliability Standards[11]

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).[12] 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.[13] 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.[14]

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

[11] 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.
[12] 16 U.S.C. § 824o.
[13] *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).
[14] *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.[15]

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."[16] 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."[17] 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).[18]

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. In October of 2009, WECC conducted its three-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 reports of both reviews 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 particular, the Operations Highlights Report contains data indicating that, since

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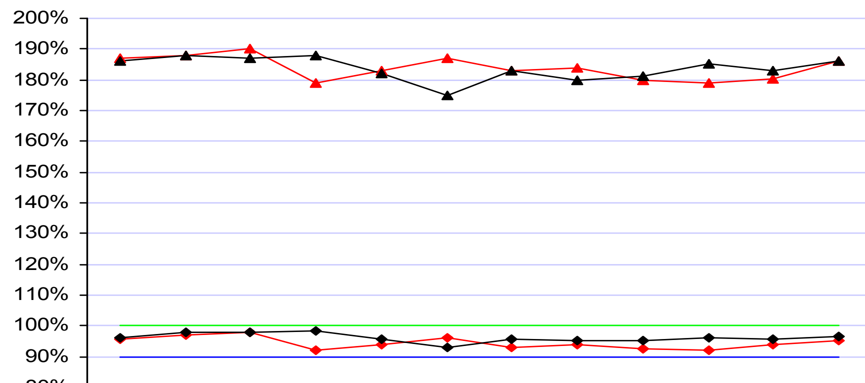
15 *North American Electric Reliability Corp.*, 126 FERC ¶ 61,229, at P 9 (2009).
16 18 C.F.R. § 39.4(a).
17 18 C.F.R. § 39.4(b).
18 *See* "WECC Compliance Monitoring and Enforcement Program," at § 4.1 (available on NERC's website at: http://www.nerc.com/files/WECC_2009_Implementation_Plan.pdf); http://compliance.wecc.biz/Application/ContentPageView.aspx?ContentID=74 (WECC web page regarding the CEMP).

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 Error (ACE) variability, CPS2, 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 percent and a CPS 2 percentage of at least 90 percent are required for full compliance. Data through the end of 2009 demonstrates that the ISO has operated the grid in compliance with these Reliability Standards.

Figure 16 provides the CPS1 and CPS2 data for January through December 2009 as well as data for 2008 for comparison. For 2009, the data shows that the CPS1 percentages were all above 100 percent and the CPS2 percentages were all above 90 percent.

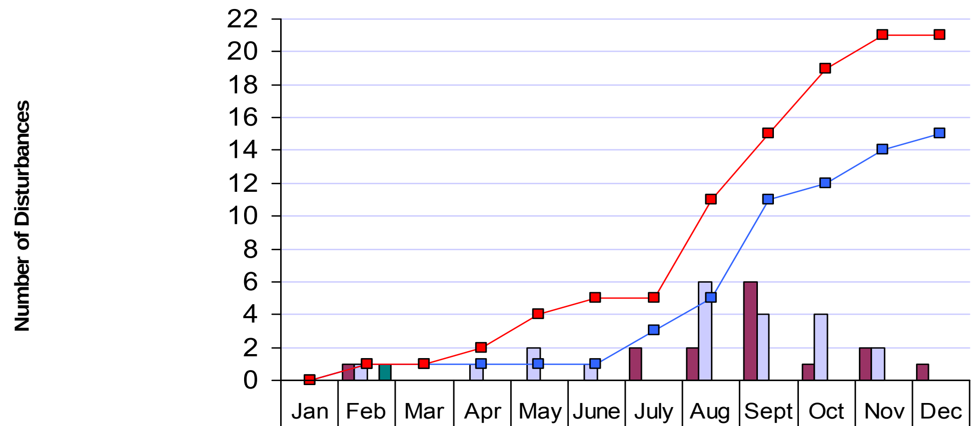
Figure 16: CPS1 and CPS2 Violations



	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
'09 CPS 1	187%	188%	190%	179%	183%	187%	183%	184%	180%	179%	180%	186%
'09 CPS 2	95.76	97.15	97.79	92.29	93.68	95.90	93.07	94.01	92.57	92.09	93.95	95.43
'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 17 provides the DCS data for January through December 2009 as well as data for 2008 for comparison. For 2009, the data shows the number of DCS violations was zero.

Figure 17: 2008 and 2009 DCS Violations



	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Inside ISO '09	0	1	0	0	0	0	2	2	6	1	2	1
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	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	1	1	3	5	11	12	14	15
'08 YTD Disturbances Total	0	1	1	2	4	5	5	11	15	19	21	21

Reliability – Assessment of Ancillary Service Control[19]

The assessment of the system's ability to meet the ancillary service control, capability and availability standards, is contained in the ISO's assessment of undelivered, undispatchable, or unavailable ancillary services capacity. The ISO computes the performance categories listed below for the determination of the rescission of payments for non-performance. Therefore, to meet this reporting requirement, the ISO reports the activity under these categories based on the settlement data available for the rescission of payments associated with the rescission of payments related to the various non-performance items.

Undelivered spinning and non-spinning capacity is determined based on whether a resource fails to deliver at least 90 percent of energy dispatched from the awarded spinning and non-spinning capacity. This ensures that resources that are paid for this ancillary service are at the dispatched operating level within 10 minutes after issuance of the dispatch instruction. See Sections 8.4.2 (b) and 8.4.3(a) of the ISO Tariff. The undelivered capacity data provides an

[19] 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." 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."

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).

assessment of the reporting requirements in item number 4 in footnote 591 of the *September 2006 MRTU Order*.

- Undispatchable spinning and non-spinning reserve capacity is determined based on when a resource has an outage or an insufficient ramp rate and cannot provide the full amount of spinning and non-spinning reserves awarded. See ISO Tariff section 8.4.4 (i). This meets the reporting requirement in item 1 footnote 591 of the *September 2006 MRTU Order*.
- Unavailable spinning and non-spinning reserve capacity is determined based on whether a resource cannot provide spinning and non-spinning reserve due to uninstructed deviations. See ISO tariff section 8.4.4(i). This unavailable capacity provides an assessment of item 4 in footnote 591 of the *September 2006 MRTU Order.*
- Unconnected spinning reserves capacity is calculated based on when a resource scheduled to provide spinning reserve is not connected to the grid. This ensures that resources scheduled to provide spinning reserve are responsive to frequency deviations. See Section 8.4.4(ii) of the ISO tariff. The unconnected capacity provides an assessment of item 2 in footnote 591 of the *September 2006 MRTU Order*.

The data for calculating these rescissions of payment is based on settlement-quality meter data. Therefore, certain results may not be included in this report because at the time of this report the ISO has not received and processed settlement-quality meter data for such charges. Results for the months that are not included will be included in subsequent quarterly reports as they become available. Figure 18 shows the trend in daily percentages of the total spinning and non-spinning capacity that was undeliverable, undispatchable or unavailable from April to October 2009 as a proportion of the total spinning and non-spinning capacity procured. The average level of non-compliance was 4.2 percent of the total spinning and non-spinning reserves procured for the time period from April to October 2009.

Figure 18: Daily Ancillary Service Non-Compliance from April to October 2009

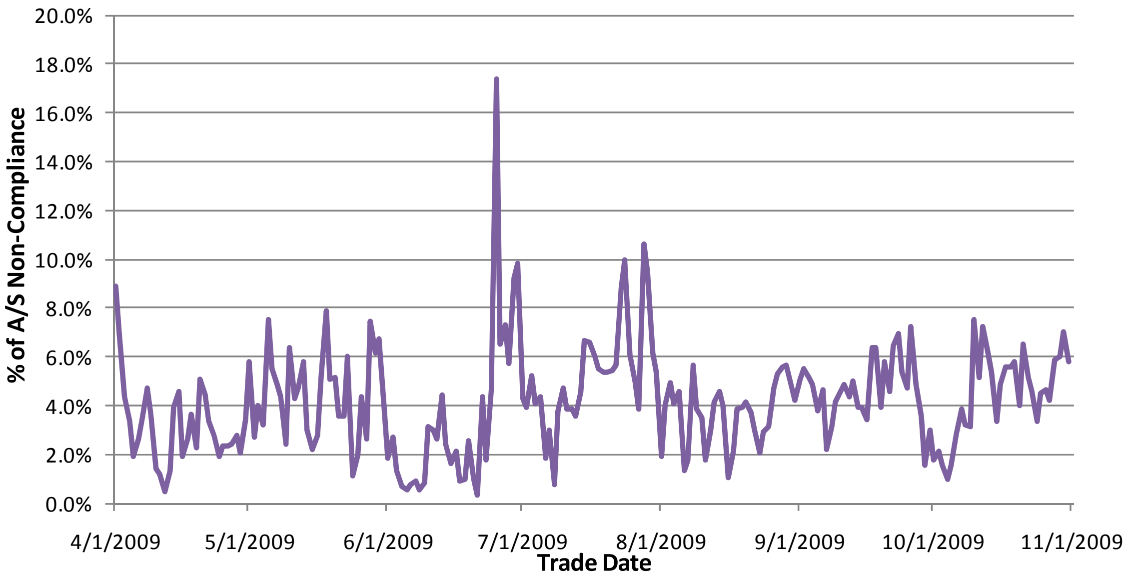
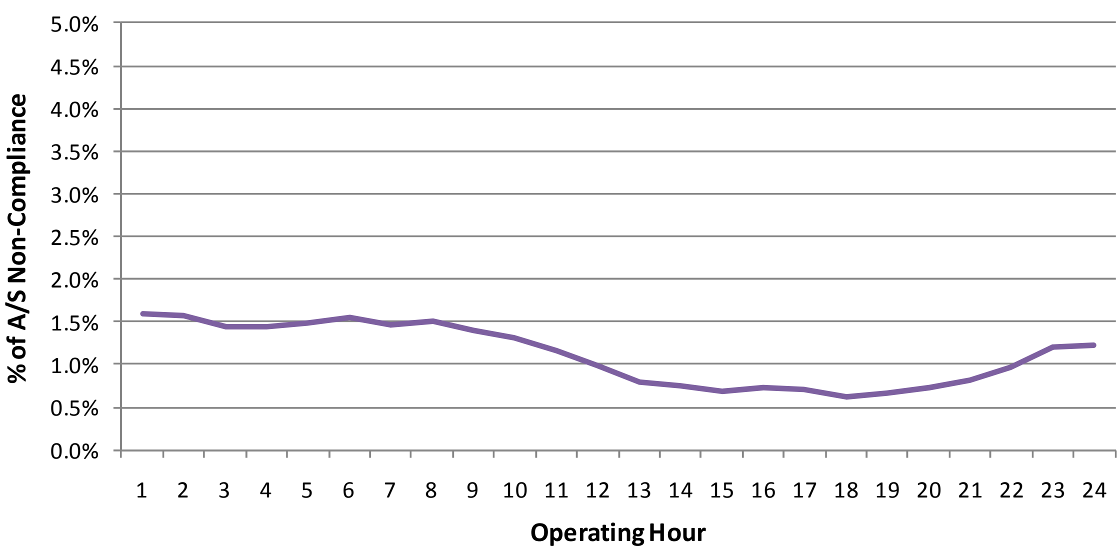


Figure 19 shows an hourly trend of the same spinning and non-spinning data, this time shown as an hourly average percentage trend.

Figure 19: Hourly Trend of Non-Compliance in Percent



Area Control Error

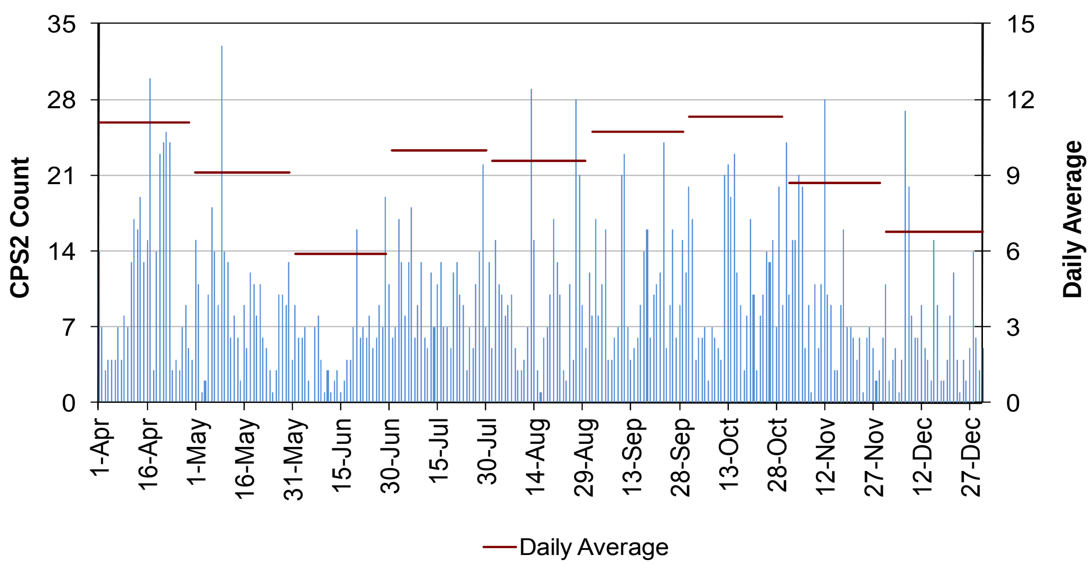
The most relevant indicator that demonstrates the ability of generators "to respond to signals from the ISO Energy Management System (EMS) to provide regulation when ACE exceeds the allowable ISO Control Area dead band for ACE" is the pattern of Control Performance Standard 2 violations. The CPS2 standard 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 in 2009 is shown in Figure 20 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).

Between the period of October 12, 2009, and November 4, 2009, the automated form of compensating injections had been turned on. However, based on observations, it was determined that during periods of high interchange ramp or inadvertent flow, the compensating injections were contributing to increasing number of CPS2 violations. As a result on November 4, 2009, the automated form of compensating injections were turned off until further refinements could be made to avoid having compensating injections contribute to the forward looking imbalance energy forecast.

Figure 20: Trend of CPS2 Violations in 2009



Voltage Control Assessment

In accordance with Paragraph 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 the ISO Tariff section 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."[20]

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 ISO 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.

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

Business Practice Manuals Proposed Revision Requests[21]

For the quarter ending December 31, 2009, two BPM Proposed Revision Requests (PRR) reports were delivered to the ISO Board of Governors for the October 29, 2009 and the December 16, 2009 Board meetings. No Board meetings were held in November, 2009. The BPM Change Management reports delivered to the ISO Board of Governors are attached to this report as Appendices 1 and 2.

[21]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[22]

There were no reported activities of bilateral transfers of resource adequacy import capability for the fourth 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.

[22] 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 resource adequacy import capability. This section provides the relevant information.

Aggregate Data on Interim Scheduling Charges[23]

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

During the month of August and September 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
8/2/2009	1	1	1	$2,966.60
8/5/2009	1	1	1	$76.94
8/6/2009	1	1	2	$2,763.26
8/10/2009	1	1	1	$1,162.52
9/11/2009	1	1	4	$133,246.31
9/18/2009	1	1	2	$15,011.96

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 months of August, September and October.

[23] 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[24]

The ISO is committed to resolving the deferred functionality items and incorporating the four deferred items, as appropriate, into its 2010-2011 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 needs 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 (FOR). The ISO sought to incorporate this functionality in an initiative to implement multi-stage generator modeling (MSG) because it had identified that the performance issues identified for the forbidden operation region functionality were reduced with the adoption of the multi-stage generator functionality. The ISO initially believed that the multi-stage generator functionally would be ready for implementation approximately six to nine months after the start of the new market. The stakeholder process on the multi-stage generator functionality began on November 7, 2008, with the posting of an initial issue paper. On May 18, 2009, the ISO Governing Board approved deployment of the multi-stage generator functionality. The ISO has also been working with its vendor to develop the MSG functionality as designed. Up until late 2009, the ISO believed it was feasible to implement multi-stage generator on April 1, 2010.

Through the latter half of 2009, the ISO began experiencing project schedule challenges with multi-stage generator modeling. In December 2009, ISO management informed the ISO Board of Governors and stakeholders that based on all the information it had received and the project schedule challenges to that point, the ISO would not be able to implement multi-stage generator on April 1, 2010 as previously anticipated. Based on comments received from stakeholders, the ISO also understands that an April 1, 2010 start for multi-stage generator also would pose an implementation challenge for stakeholders.

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[24] 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.

At this time the ISO anticipates that the multi-stage generator functionality will be implemented in Fall 2010. As an interim measure, the ISO has decided to pursue implementation of the forbidden operating region functionality in the real-time market.

The current status of this initiative is as follows:

- Software changes in the core real-time market application were delivered in December 2009 and have undergone extensive testing and validation;

- The ISO filed the tariff language on January 28, 2010, that allows the ISO to comply with the FERC order to re-instate the real-time forbidden region functionality;

- Market simulation scenarios have been defined and reviewed with stakeholders and will begin on March 1, 2010; and

- Forbidden operating regions is on track for deployment on April 15, 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) multi-stage generator, 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 was deployed on November 12, 2009. Deployment of multi-stage generator is currently scheduled for October 2010. The ISO has determined that until it has adopted the multi-stage generator functionality, it cannot fully evaluate whether the restrictions on Operational ramp rate changes are still necessary. Therefore, the ISO is delaying this determination until the multi-stage generator functionality is implemented. In the interim, the ISO proposes to maintain the current restrictions on the operational ramp rate changes.

3. Procurement of ancillary services in the hour ahead scheduling process

On December 23, 2009, the ISO filed proposed tariff amendments for approval from FERC that will enable the ISO to implement the ISO's ability to procure ancillary services in the hour-ahead scheduling process (See FERC Docket No. ER10-479). The current status of this initiative is as follows:

- Software changes in the core market applications were delivered in January 2010 and are undergoing extensive testing;

- Market simulation scenarios have been defined and reviewed with stakeholders and market simulation will begin on March 1, 2010; and

- This functionality is on track for deployment on April 1, 2010, as planned.

4. Extremely Long Start Process

Automation of the commitment process for extremely long-start resources may be of limited value since the ISO has 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 Adjustment of Non-Priced Quantities[25]

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 of the new market on April 1, 2009, these parameters have only rarely affected the day-ahead market results. There have been no locational marginal prices at LAPs (the location at which most of the load is scheduled and settled) that have approached the levels that would result in adjustment of self-schedules for demand at their respective LAPs. Final schedules have been adjusted to conform to transmission limits when effective generation or intertie schedules are available, and at such times have been priced at -$30/MWh. This confirms that the mechanism for market adjustments to generation and imports self-schedules is functioning as intended.[26]

In the period addressed in this analysis, sufficient economic bids were generally available to enforce transmission limits without adjustments to self-schedules. Two exceptions were: (1) on October 3, following a derate of the California-Oregon intertie constraint, self-schedules on a small share of contract capacity identified as the COTPISO_MSL market scheduling limit exceeded the available capacity for 16 hours, resulting in -$30/MWh prices, and (2) for one hour on December 14, the capacity of a transformer in Humboldt substation

[25] 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."

[26] The instances where generation and import self-schedules were adjusted occurred because the volume of self-schedules exceeded the capacity of intertie constraints or the ratings of radial, local transmission systems. The market optimization resolves these constraints by representing the supply self-schedules with an "uneconomic" bid segment price of -$550/MWh in the initial scheduling run, determining the amount by which these schedules have been adjusted using the uneconomic bid price, and then using an uneconomic bid segment between the original self-schedule and the adjusted self-schedule minus a small quantity known as epsilon, with this bid segment being priced at -$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.) This mechanism produces locational marginal prices of $-30/MWh at the location of the constrained self-schedule. Locational marginal prices of -$30/MWh may also be set by economic bids that are priced at the bid floor. When congestion can be managed without relaxing the capacity limits and without adjusting self-schedules, the shadow prices of constraints are then set by economic bids, within the range of penalty prices used in the scheduling run's optimization, and can exceed the penalty prices used in the pricing run. Shadow prices of constraints can also exceed the penalty prices used in the pricing run if no schedules are available for adjustment by the market optimization

(31000_HUMBOLDT_115_31001_HMBLT TM_ 1.0_XF_1, which is a 115 to 60 kV transformer) constrained generation to less than its self-schedules.[27]

When it is necessary to relax transmission constraints to resolve congestion, the market optimization resolves these constraints by pricing violations at $5000/MW in the initial scheduling run, to determine the required amount of constraint relaxation. The adjusted 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 locational marginal prices for resources whose incremental or decremental adjustment contributes to the constraint is their power transfer distribution factor (PTDF, also commonly known as "shift factor") times the shadow price of the transmission constraint.[28] For example, the congestion component of the locational marginal prices for a generator whose output adds to flows on a congested constraint with a shadow price of $500/MW, and that has a power transfer distribution factor of 5 percent for the congested constraint, would be 0.05 * $500 = $25/MWh.

This mechanism has successfully limited constraint relaxation while producing moderate LMPs. The following constraints have been subject to shadow prices in excess of $500 in the day-ahead market during the period reported here:

- On 11/18/09, hour ending (HE) 6, and 11/21/09, HE 18, the HUMBOLDT_BG corridor was relaxed by 0.2 and 1.4 MW, respectively, due to inadequate supply in the Humboldt area during a generation outage. This constraint produced a pricing run shadow price of $500/MW in each instance. Locational marginal prices for generation in the Humboldt area were $534 to $537/MWh during these hours due to the most effective generation being over 99 percent effective in managing this constraint.

- On 12/10/09, hour ending 17, a temporary constraint that was enforced during transmission testing (1051307-SOL3) was relaxed by 1 MW at a shadow price of $1613/MW. In addition, a 115 kV transmission line (33203_MISSON _115_33204_POTRERO _115_BR_1 _1) was relaxed by 3.9 MW, at a shadow price of $1000/MW of congestion cost due to two contingency power flow analyses that each contributed $500/MW to the shadow price of this constraint. After available generation bids were

27 In addition to these instances, two hours of prices below -$30/MWh occurred on 11/5/2009, when the Blythe intertie had an operating transfer capability of zero MW for both imports and exports. This required all schedules to be reduced to zero MW. These prices occurred as a self-schedule was submitted as a block of 24 hours, which would require the same schedule in all hours. The cost of enforcing the block scheduling constraint exceeded the normal -$30/MWh penalty price that applies to single hours in the optimization, thus the combined result is within the applicable penalty prices.

28 See Appendix C of the ISO Tariff for further details.

dispatched to the extent possible, the locational marginal prices for San Francisco generation reached -$466/MW.

From this analysis the ISO concludes that 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 closely monitor all instances of constraint relaxation in the day-ahead market to ensure that the parameters continue to result in reasonable locational marginal prices 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 number of economic bids to obtain a feasible and reasonable solution. Since the implementation of the new markets, such adjustments have not been significant in the real-time market. Additionally, data for the most recent three-month period from October through December 2009 shows significant reductions in uneconomic adjustments relative to the first two quarters of the new-market operation starting April 1, 2009.

The following section provides an assessment of the existing non-priced quantity parameters. It should be noted that unless a market participant explicitly submits an economic bid in the real-time market to be used to dispatch the resource below its day-ahead schedule for energy, the day-ahead energy scheduled amount is effectively a self-schedule in the real-time market and with 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 day-ahead and the real-time markets, rendering accepted schedules in the day-ahead market no longer feasible in real-time.

Real-Time Dispatch (RTD)

The real-time dispatch is executed every five minutes and dispatches generating resources to meet load variations in real-time. During the three-month period from October 1, 2009 to December 31 of 2009, 8.82 percent of the intervals had one or more adjustment of non-priced quantities in the real-time dispatch market solution. This represents a significant reduction versus the 16.09 and 15.53 percent respectively of the previous two quarters of new-market operation. Adjustment of non-priced quantities in the real-time market includes:

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

The significant reduction in the number of intervals in which non-priced quantities were adjusted is mainly due to the modification of the real-time software since August 1 to represent how regulating reserve is used to balance short-term high-frequency load fluctuations. This modification allows limited relaxation of the power balance constraint through a lower scheduling run penalty price. These modifications would account for the effect of regulation ramping capability that will naturally be provided by resources providing regulation via automated generation control (AGC).[29] Such relaxation of the energy requirement is intended to reflect the deployment of energy from the regulation reserve capacity to meet the overall energy balance constraint. The actual relaxation amount varies. The capacity that is available is equal to the regulation reserve procurement amounts, which vary hour by hour, but are generally around 350 MWs in each direction. The penalty price associated with this relaxation is relatively low compared to the penalty prices incurred for other non-economic adjustments. Thus in overgeneration and supply-shortage situations, and when economic adjustments have been exhausted, the use of the energy requirement relaxation that reflects regulation produces a market solution in the scheduling run that does not make use of uneconomic adjustments or adjustments of non-priced quantities with higher penalty prices. The market optimization process in the market appropriately relies on this method to reach a feasible and reasonable solution that is more reflective of actual operating practices when acute energy or ramping deficiency occurs. In other words, when there is insufficient economic energy available to balance the system, the system will automatically balance to the extent it can using regulation, rather than curtailing self-schedules uneconomically, until the additional market energy becomes available. The three types of uneconomic adjustments or adjustment of non-priced quantities observed during the final quarter of 2009 are described below:

Supply Energy

In the real-time dispatch, supply self-schedules can be curtailed due to system-wide over-generation, over-generation in a small generation pocket, over-generation in a large congestion area, or insufficient effective economic bids on the decremental side of a congested transmission constraint. The penalty price for the real-time dispatch self-schedules in the scheduling run is set at -$1600 for the lowest priority self-schedule curtailments of generation and imports and becomes more negative for other self-schedules that have a higher priority for protection. Imports are scheduled on hourly basis in day-ahead and in hour ahead scheduling process and are modeled as self-scheduled resources in real-time dispatch. The real-time dispatch software is designed so that import energy that cleared in hour-ahead scheduling process can be adjusted if necessary to obtain a market solution, even though such adjustment will not be carried out in actual operation under normal circumstances but does provide the operator

[29] Prior to relaxing the power-balance constraint in the scheduling run at a penalty price of $6500, the power-balance is allowed to relax at a price slightly above the bid cap in cases of acute under-generation conditions and slightly lower than the bid floor for acute over-generation conditions. This relaxation is only for a limited quantity of megawatts reflective of a portion of awarded regulation capacity to account for the effect of regulation ramping capability that will naturally respond to meet load in real-time

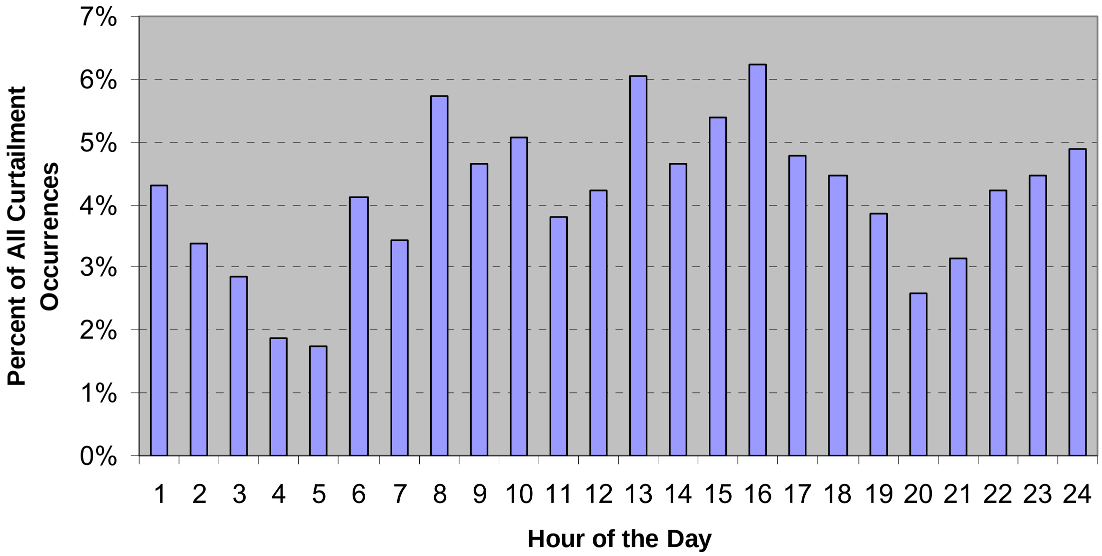
information in case manual action is necessary. Subsequently, in the pricing run, the associated pricing parameter is set to -$30/MWh, the bid floor, and is used to price the self-schedule curtailment of the supply resource. As such, locational marginal prices of the pricing run for resources undergoing self-schedule curtailment in the scheduling run are less than or equal to -$30/MWh.

The ISO's analysis of the first three quarters of operation of the new markets reveals that the energy self-schedule parameter settings in the real-time dispatch continue to be appropriate. The results from the final quarter of 2009 generally align with the previous two quarters of new market operations. The analysis shows that:

1. Self-schedule curtailments of generating resources and imports to resolve the constraint violations did not occur very often.
2. Among those intervals with self-schedule curtailments, in most instances the pricing run system LAP and default LAP prices were near or above the -$30/MWh bid floor level. During periods of system-wide or large congestion area over-generation, the pricing run system LAP price and/or default LAP prices were usually around -$30/WMh. On the other hand, resolving congestion of local transmission constraints resulted in limited locations within the system with negative LMPs in the pricing run and default LAP prices significantly above the -$30/MWh level.
3. In rare instances, default LAP prices or system LAP prices in the pricing run were significantly lower than -$30/MWh 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 real-time dispatch market results shows that uneconomic adjustments or adjustment of non-priced quantities occurred in 6.24 percent of the five-minute intervals, a reduction from the 10.48 percent of second quarter 2009 and 12.26 percent of third quarter 2009. This reduction is due to the implementation of energy requirement relaxation reflecting the role of regulation described above. During the three-month period these adjustments occurred 35.79 percent of the time for October, 48.97 percent of the time for November and 15.24 percent of the time for December. Figure 21 shows the curtailments as a percentage of the total occurrences for different hours of day over the three-month period from October through December 2009.

Figure 21: Percentage of Supply Energy Adjustment of Non-Priced Quantities Curtailments by Hour



The chart above does show a different hour-of-the-day profile than that occurred in the previous two quarters. In the past, during off-peak hours, in which over-generation occurs more frequently, it was more likely to have instances of supply energy self-schedule curtailment. Figure 21 instead shows no such pattern. With the adoption of the energy requirement relaxation reflecting the role of regulation, over-generation conditions are less likely to require supply self-schedule curtailment to reach a market solution when there are no effective economic bids. In this quarter, the most common adjustment of non-priced quantities is the curtailment of import energy self-schedules to resolve radial congestion, where the self-schedules being curtailed are day-ahead final schedules defaulting to the real-time market. Such congestion does not show any hour-of-the-day pattern.

Among all the supply self-schedule curtailment intervals, 73.8 percent of the time it is due to congestion on tie-point limit or branch group constraints (with the radial nature for the inter-tie import resources). Real-time dispatch run analysis shows that the reasons for congestion are:

- De-rate of branch group limits from day-ahead to real-time.
- Reduction of available transfer capability (ATC) at tie points from day-ahead to real-time.
- While there is no change in branch group limits and tie-point limits from day-ahead to real-time, there are numerical issues in defaulting day-ahead market final schedules of imports as real-time market self schedules. Such numerical problems resulted in the total amounts of self-schedules slightly exceeding the branch group or tie-point limits that the import self-schedules are subject.

Among the self-schedule curtailment intervals, over-generation system-wide or in large congestion areas occurred 2.12 percent of the time (or 0.13 percent in the three-month period). The 0.13 percent in the three-month period is a dramatic decrease from the previous two quarters. During these intervals, LAP prices for the over-generation area were near -$30 for 71.43 percent of intervals (or 0.09 percent of the three-month period) and 28.57 percent (or 0.04 percent of the three-month period) LAP prices were more negative than −$40. All these figures which show an extremely low percentage of occurrences within the three-month period reflect the increased reliance on the energy requirement upward relaxation in the scheduling run at a price of −$35. This is because the market run optimization process has primarily employed this mechanism rather than supply self-schedule curtailment to arrive at a market solution during over-generation conditions. For most of intervals with energy self-schedule curtailments, curtailments were made to resolve local congestion and, thus, default LAP prices were well above -$30.

Export Energy

Export energy self-schedule curtailment in real-time dispatch can be caused by a system-wide supply-shortage; a supply-shortage in a small generation pocket or even in a large congested 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 hour ahead scheduling process. Exports schedules do not have economic bids in the real-time dispatch and are modeled as self-schedules. A penalty price of $1600 is used for uneconomic adjustments of export self-schedules to achieve a market solution. However, the export adjustment will not be carried out in actual operation under normal circumstances but does provide the operator information in case manual action is necessary. A higher penalty price is used for other higher priority export energy self-schedules. The pricing run pricing parameter is set at $500, the current bid cap, and is used to set the price for the self-schedule curtailment of the export resource. As such, locational marginal prices of pricing run for exports undergoing self-scheduling curtailment are at or above $500/MWh.

Similar to the ISO’s previous quarter analysis, the analysis for October through December shows that the initial export self-schedule curtailment parameters have also been appropriate because:

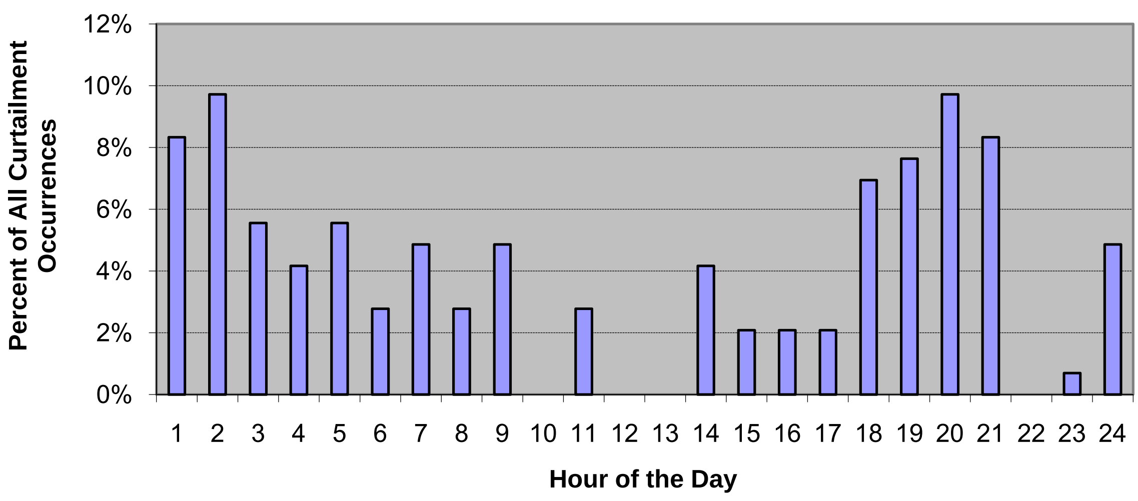
1. Self-schedule curtailment of exports has rarely occurred.
2. In instances where there were export self-schedule curtailments, the majority of intervals had pricing run LMPs which were not significantly above the $500 bid cap. Among such instances, pricing run system LAP and/or default LAP prices around $500 indicated a system wide or large congestion area supply shortage. On the other hand, when resolving congestion of a local transmission constraint, the pricing run LMPs could have values above the $500 level in localized areas but the resulting default LAP prices were well below the $500 level.

3. In instances where there was export self-schedule curtailment, a small number of intervals (7.64 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, there were only a small number of occurrences of export energy self-schedule curtailments during the period of this analysis.

The ISO's analysis reveals that only 0.54 percent of real-time dispatch intervals had export energy uneconomic adjustments, a substantial reduction from the 1.94 percent of previous quarter. This reduction is once again due to the implementation of the relaxation of the energy requirement reflecting the role regulation in scheduling run of the real-time dispatch that has been explained above. The energy requirement downward relaxation rather than export self-schedule curtailment has become the primary mechanism to reach the optimal market solution when there is supply shortage. For intervals with export energy uneconomic curtailments, 49.31, 27.78, and 22.92 percent occurred in October, November and December 2009, respectively.

Figure 22 shows the hourly adjustment occurrences in percent of the total adjustment occurrences over the three-month period from October 1 through December 31, 2009. The chart does not show the same hour-of-the-day profile as it did in the previous two quarters.

Figure 22: Percentage of Export Energy Uneconomic Adjustments by Hour



In the past, peak hours, where supply shortages occurs more frequently, were more likely to have instances of export energy self-schedule curtailment. Figure 22 does not demonstrate this same pattern. With the energy requirement relaxation reflecting the role of regulation in the scheduling run that has been implemented, there is much less reliance on export energy self-schedule curtailment as a mechanism to reach a market solution when economic bids have been exhausted. Instead the optimization relies on energy requirement downward relaxation during times of acute supply shortages. Resolving radial congestion has become a key factor among all other causes of export uneconomic curtailment. Such congestion is similar to those discussed in the supply self-schedule curtailment section and does not have any hour-of-day pattern.

Among the export self-schedule curtailments in the real-time dispatch, supply-shortage system-wide or in a large congested area occurred 40.28 percent of time (or 0.22 percent over the three-month period). LAP prices in the supply-shortage area were around $500/MWh in 32.64 percent of time (or 0.18 percent over the three-month period) and above the $600/MWh level in 7.64 percent of the time (or 0.04 percent over the three-month period). For the remaining intervals in which curtailments were used to resolve congestion, default LAP prices were significantly below the $500/MWh bid cap.

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 the real-time dispatch can be caused by a supply shortage in a large congested area that requires extra energy to flow from another area. In these circumstances transmission constraint relaxation has a high penalty price and is generally only invoked to reach a market solution after running out of both economic energy requirement downward relaxation and export curtailments from the area. It can also occur when the market optimization has insufficient effective economic incremental and/or decremental bids and/or ramping capability to resolve local transmission constraint violations.

Transmission constraints include flowgate and nomogram limits in addition to thermal line limits. The market optimization uses a penalty price of $5000/MWh to relax transmission constraints in the scheduling run to provide transmission constraints a higher priority over energy self-schedule curtailments. The pricing run parameter for transmission constraint relaxation is $500/MWh, which is the bid ceiling. As such, the pricing run shadow price of the transmission constraint that has been relaxed in scheduling run is at or above $500/MWh.

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

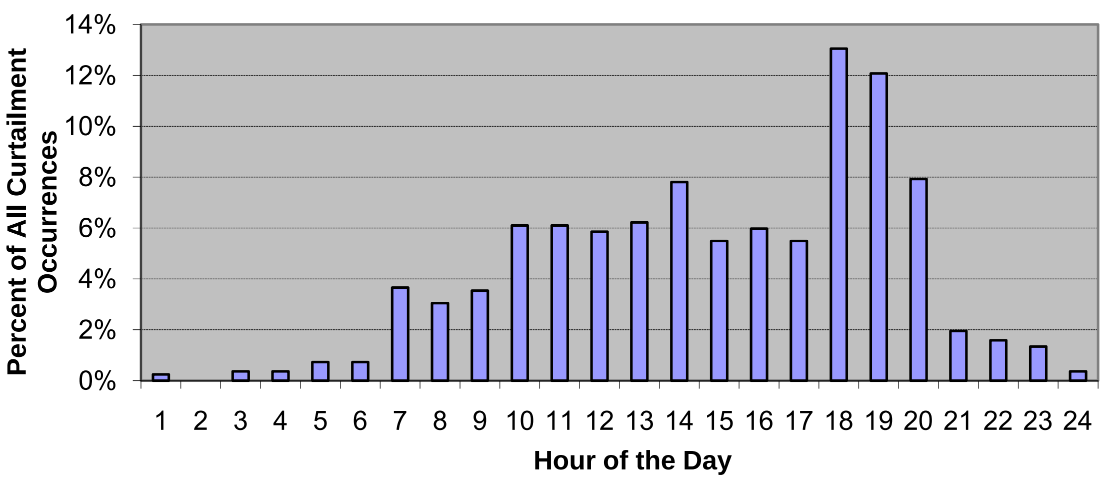
1. Transmission constraint relaxation occurred infrequently and, when it did occur, the amount of relaxation was small in most cases.
2. Among intervals with transmission constraint relaxation, locational marginal prices around the constraint were often set beyond the bid ceiling/floor range of –$30/MWh to $500/MWh. However, default LAP prices are well within the range.

3. In rare instances of large congested area supply shortage that 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 of $2000/MWh to $5000/MWh range. The cause of such extremely high default LAP prices in the pricing run has been identified as a mathematical modeling issue in the linearized optimization formulation that involves 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 explained to market participants previously.[30]

The real-time market results show that transmission constraint relaxation occurred in 3.09 percent of all the five-minute intervals of the three months, slightly exceeding the 2.58 percent for the previous quarter. Among the five-minute intervals of the transmission constraint relaxation occurrences, 20.85, 21.71 and 57.44 percent occurred in October, November and December, respectively.

Figure 23 shows the hourly transmission constraint relaxation occurrences as a percentage of all curtailment occurrences for October through December 2009. This chart shows that transmission constraint relaxation in the market solution is more likely to occur during peak-hour intervals.

Figure 23: Hourly Transmission Constraint Relaxation



It should be noted that supply-shortage in a large congestion area could be resolved by either system energy requirement downward relaxation at $500 or transmission constraint relaxation into the shortage area at $5000 penalty price depending on the effectiveness of the mechanism regarding the location and the

30 See technical bulletins at: http://www.caiso.com/2381/2381f87327f70.html

size of the shortage area. It should also be noted that over-generation in a large congestion area will not be resolved by transmission constraint relaxation nor supply self-schedule curtailment but rather by system energy requirement upward relaxation at –$35.

For 92.80 percent of the time intervals with transmission constraint relaxation in the real-time market solution (time (or 2.87 percent over the three-month period) relaxation was due to the inability of the market software to resolve local area transmission congestion through decremental and incremental generation adjustments, both economic and uneconomic. Default LAP prices were in the range of -$30/MWh to $500/MWh during these periods.

For the remaining 7.2 percent of the time when transmission constraint relaxation occurred (or 0.22 percent over the three-month period), relaxation was necessary to transfer energy to the supply shortage area. During large supply area shortage time intervals, very high default LAP prices of several thousand dollars were observed in the previous quarters, although this was extremely rare. In this quarter no similarly high default LAP prices have been observed.

Real-time Unit Commitment (RTUC)

Real-time unit commitment 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. Real-time unit commitment schedules ancillary services and energy for which ancillary services schedules and pricing are binding for the first interval of the optimization horizon of each run. For real-time unit commitment, the parameter analysis focuses on the uneconomic adjustments relevant to meeting ancillary services requirements. The relevant uneconomic adjustments include ancillary services minimum requirement relaxation and energy self-schedule curtailment to create unloaded capacity for ancillary services.

Ancillary services minimum requirement relaxation

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

During the months of October, November, and December of 2009, the real-time unit commitment parameters have been largely appropriate for the following reasons:

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

The three-month real-time pre-dispatch market results show that out of the 8832 15-minute intervals, ancillary services minimum requirement relaxation occurred in only seven 15-minute intervals or 0.08 percent of time. Three of the seven intervals are the four 15-minute intervals of September 27 2009, hour ending 10, intervals 2, 3 and 4. Among these three intervals, ancillary services requirement relaxations were observed for either spinning or non-spinning or both for the ISO expanded region and the SP-26 expanded region. The remaining four intervals are December 17 2009, hour ending 8, intervals 1, 2, 3 and 4 where regulation-down requirement are relaxed for SP-26 region.

Energy self-schedule curtailment

Energy self-schedule curtailments occur to unload capacity so that it can provide ancillary services under supply shortage situations. Uneconomic adjustments to the energy self-schedule use the parameters discussed in the real-time market section above. An analysis of energy self-schedule curtailments for providing ancillary services reveals that: energy self-scheduling curtailment for ancillary services provision did not occur in any of the 15-minute real-time pre-dispatch interval within the three-month period.

Price Cap Use[31]

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 locational marginal prices, ancillary service marginal prices and residual unit commitment capacity availability prices for the integrated forward market, residual unit commitment, hour-ahead scheduling process 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

[31] 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 24 and Table 8 show the frequency with which the price caps were applied in the different market runs that procure products subject to the price cap from October 1 through December 30. 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 hour-ahead scheduling process (procuring energy from the ties); the real-time unit commitment run (procuring ancillary services in real-time, and run every fifteen minutes beginning in the middle of each quarter hour segment); and real-time dispatch (procuring energy every five minutes and run every five minutes in real time).

During the reporting period, there were a total of 133 intervals of the hour-ahead scheduling process and real-time unit commitment run during which the price cap was applied to prices at one or more nodes, increasing by 20 compared with the third quarter. There was no price cap applied to the day-ahead market and real-time dispatch. As shown in Figure 24 and Table 8, the number of price caps for the real-time unit commitment run followed a decreasing trend while the number of price caps for the hour-ahead scheduling process showed an increasing trend.

Figure 24: Count of Price Caps

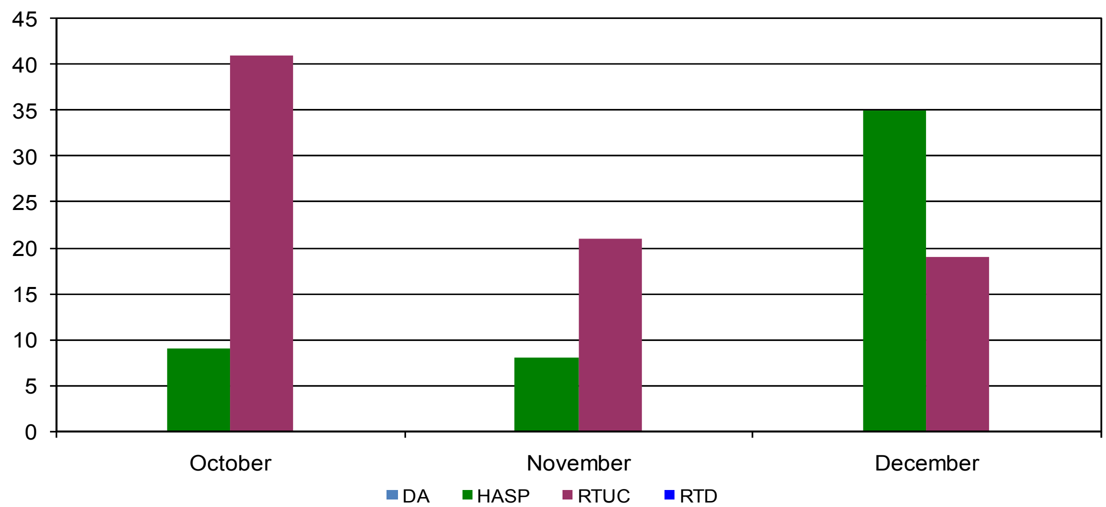


Table 8: Summary of Price Caps

Month	DA	HASP	RTPD	RTD
October	0	9	41	0
November	0	8	21	0
December	0	35	19	0
Total	0	52	81	0

Price Cap Analysis[32]

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[33].

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:

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

Lossless Shift Factor[34] 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.

A Notable case where this phenomenon occurred was only on December 8, with congestion in the Imperial Valley bank due to reduced line limits for reliability margin.

[32] 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.
[33] Weekly reports that describe the price correction activities are published at the following location: http://www.caiso.com/237b/237b797854580.html
[34] 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: LA- Fresa branch congestion on November 23, December 4, 10 and 18 of 2009. These events were due to line outages and reduced line limits for reliability margin.

Business Practice Manuals
Change Management Report
October 21, 2009

California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Karen Edson, Vice President, Policy & Client Services

Date: October 21, 2009

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

This memorandum does not require Board action.

EXECUTIVE SUMMARY

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

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 the BPM Appeals Committee, which is comprised of three ISO officers.

As of October 12, 2009, 66 proposed revision requests (PRRs) were active in the BPM change management system, 95% of which were submitted by the ISO. These 66 active PRRs impact the following BPMs:

33	Settlements and Billing
21	Transmission Planning Process
5	Market Operations
3	Reliability Requirements
1	Credit Management
1	Market Instruments
1	Metering
1	Outage Management

No BPM decisions are under stakeholder appeal.

PROCESS OVERVIEW

The ISO held the monthly BPM change management stakeholder meeting on September 22, 2009. The meeting, which was conducted by conference call, included 39 stakeholders. Based on the nature of that meeting, and upon the types of comments entered into the BPM change management electronic system, it appears that stakeholders are generally satisfied with the process, as well as with the progress made on the active PRRs. No significant concerns are currently pending on the active PRRs.

BPM CHANGE MANAGEMENT REPORT

The current *Board Update: BPM Change Management Process* report, which includes all the active PRRs as of October 12, 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 October 12, 2009;
- Reflects those PRRs upon which Management has posted its final decision for the period August 20, 2009 through October 12, 2009; and
- Includes PRRs currently under stakeholder appeal, the stakeholder positions on rejected PRRs, and the reasons for rejection.

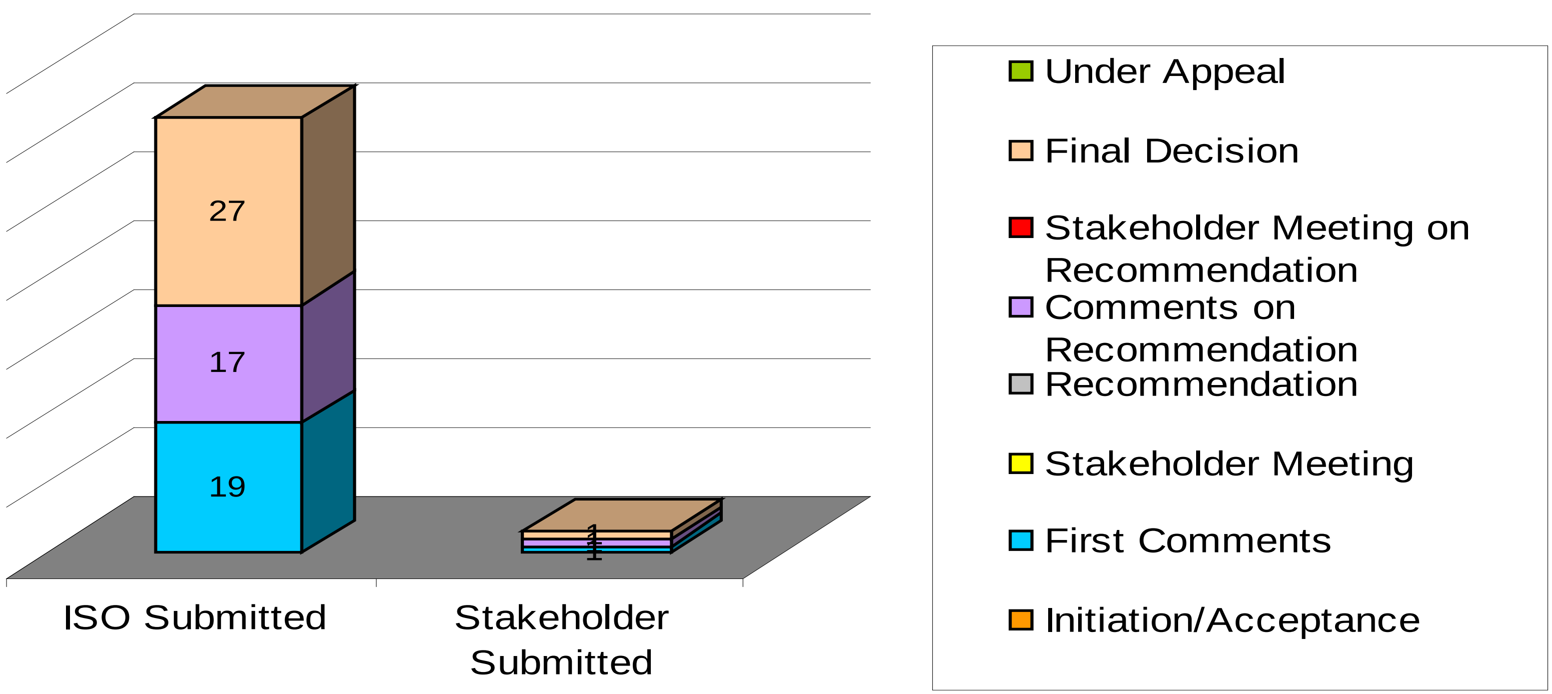
The following is additional relevant information:

- No PRRs are under appeal;
- Twenty of the active PRRs were submitted into the electronic system by the ISO on an emergency basis
    - nineteen of those PRRs are related to the Settlements and Billing BPM; and
    - one PRR pertains to the Reliability Requirements BPM
- A PRR report summarizing the PRRs in the BPM change management system as of October 12, 2009, is included as Attachment 2.

Board Update: BPM Change Management Process
October 29, 2009 Board Meeting

Attachment 1

Active Proposed Revision Request (PRR) Status



- Initiation/ Acceptance
- First Comments
- Stakeholder Meeting
- Recommendation
- Comments on Recommendation
- Stakeholder Mtg on Recommendation
- Final Decision
- Under Appeal

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Attachment 1

Active PRR Stage	# of PRRs
First Comments	20
Comments on Recommendation	18
Final Decision	28
Total	**66**

Business Practice Manual (BPM)	# of PRRs
Credit Management	1
Market Instruments	1
Market Operations	5
Metering	1
Outage Management	1
Reliability Requirements	3
Settlements and Billing	33
Transmission Planning Process	21
Total	**66**

Attachment 1

Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	22	Formula Change to CC 6700 Section 3.6.1.2	Final Decision	The ISO is adopting the 2nd recommendation as originally issued, without modifications.
Reject	31	Clarification on transmission interface constraints modeling in market software	Final Decision	ISO to post updated Market optimization technical bulletin containing the information requested in this PRR. No changes will be made to the BPM at this time related to this PRR 31. The technical bulletin will be posted by the end of September, 2009.
Reject	32	Clarification on the calculation of the system marginal energy cost (SMEC)	Final Decision	ISO to post updated "Market Optimization" technical bulletin containing information requested in this PRR 32. No changes will be made to the BPM at this time related to this PRR 32. The technical bulletin will be posted by the end of September, 2009.
Accept	33	Dispatchable RUC Capacity	Final Decision	CAISO is adopting recommendation.
Accept	34	New BPM Configuration Guide for CC 7989 effective with Payment Acceleration	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	35	New BPM Configuration Guide for CC 7999 effective with Payment Acceleration	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	36	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.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.

California ISO
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Attachment 1

Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	37	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.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	38	Master File Update (User Interface)	Final Decision	The Market Instruments BPM will be updated with the proposed changes outlined in PRR 38.
Accept	39	New Expected Energy Types	Final Decision	The ISO did not receive any comments to the posted recommendation. As a result, final decision is that ISO is going to accept all the proposed changes to the BPM mentioned in the recommendation.
Accept	41	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.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	42	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.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.

Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	43	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□.	Final Decision	The ISO is adopting the recommendation as originally issued, without modifications.
Accept	44	Update the BPM Configuration Guide formula for 6620 precalculation to include exports in bid cost recovery calculation	Final Decision	The ISO is adopting as proposed in its recommendation.
Accept	45	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.	Final Decision	The ISO is adopting as proposed in its recommendation
Accept	46	FNM Update Process Flow Diagram - Update	Final Decision	No comments were received on this PRR 46 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This change is effective when the PRR process is complete.
Accept	47	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.	Final Decision	The ISO is adopting as proposed in its recommendation.

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	48	Updated BPM Configuration Guide for ETC, TOR, CVR Quantity Recalculation to implement New Bill Determinant for contract entitlement used in DA Energy contract balancing	Final Decision	The ISO is adopting as proposed in its recommendation
Accept	49	Reliability projects are to be submitted by PTOs by October 15.	Final Decision	For A (section 2.1 The ISO Transmission Planning Process) the ISO's recommendation was adopted. For B (section 2.1.2.3 Stage 2: Technical Studies and Presentation of Results) the ISO's recommendation was adopted with minor modifications as follows: Language as recommended: B. As discussed earlier in this BPM, the PTOs are required to submit reliability transmission projects through the Request Window by October 15 each year that respond to the needs and criteria violations identified by the ISO in the current TPP cycle, including any agreements to implement the mitigation solutions proposed by the ISO. To the extent a PTO proposes a mitigation solution that differs from the ISO?s proposed solution, the PTO must fill out the Request Window Submission Form with as much detail as possible and then supplement it with additional information. The additional information needs to be submitted prior to the closing of the Request Window. Language as modified: B. As discussed earlier in this BPM, the PTOs are required to submit reliability transmission projects

Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				through the Request Window by October 15 each year that respond to the needs identified by the ISO in the current TPP cycle, including any agreements to implement the solutions proposed by the ISO. To the extent a PTO proposes a solution that differs from the ISO's proposed solution, the PTO must fill out the Request Window Submission Form with as much detail as possible and then supplement it with additional information. The additional information needs to be submitted prior to the closing of the Request Window.
Accept	50	Request Window submissions must respond to the needs identified by the ISO	Final Decision	ISO's recommendation was adopted as posted.
Accept	51	The NERC Reliability criteria violation recommended solution	Final Decision	ISO recommendation was adopted with minor modifications as follows: Language as recommended: A. PTOs must submit mitigation solutions for the needs and criteria violations identified by the ISO, or their agreement to pursue implementation of the ISO's recommended solution, through the Request Window during the TPP cycle in which the need or criteria violation was identified, unless the ISO, in consultation with the PTOs, establishes a different time frame in which this information is to be provided if required by the complexity of the project and other pertinent factors Language as modified: A. PTOs must submit reliability transmission projects for the needs identified by the ISO or their agreement to

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				pursue implementation of the ISO's recommended solution through the Request Window during the TPP cycle in which the need was identified, unless the ISO, in consultation with the PTOs, establishes a different time frame in which this information is to be provided if required by the complexity of the project and other pertinent factors. ISO's recommendation was adopted with minor modifications as follows: Language as recommended: B. The ISO will post its study results by September 15 of each annual study cycle. The PTOs must submit reliability transmission project proposals through the Request Window by October 15th of each year to allow sufficient time for TPP participants to review such project proposals. Mitigation solutions that will address needs or criteria violations identified by the ISO studies, including ISO-proposed solutions with which the PTO agrees and solutions that have been developed by the PTO in whose service territory the need has been identified, must be submitted through the Request Window for the TPP cycle in which the need or violation was identified. The ISO will host its 2nd annual public meeting towards the end of October to present the results and proposed mitigation plans. Language as modified: B. The ISO will post its study results by September 15 of each annual study cycle. The PTOs must submit reliability transmission project proposals through the

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				Request Window by October 15th of each year to allow sufficient time for TPP participants to review such project proposals. Reliability transmission projects that will address needs identified by the ISO studies, including ISO-proposed solutions with which the PTO agrees and solutions that have been developed by the PTO in whose service territory the need has been identified, must be submitted through the Request Window for the TPP cycle in which the need was identified. The ISO will host its 2nd annual public meeting towards the end of October to present the results and proposed mitigation plans.
Accept	52	General Description of Request Window Categories	Final Decision	ISO recommendation was adopted as posted.
Accept	53	The transmission owner of the system to which a generation will be interconnected to must submit network upgrades through the Request Window.	Final Decision	ISO recommendation was adopted.
Accept	54	Generation projects must go through the GIPR in order to interconnect to the ISO Grid.	Final Decision	No comments were received on this PRR 54 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This change is effective when the PRR process is complete.
Accept	55	Categories of Request Window Submissions	Final Decision	ISO recommendation was adopted as posted.

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	56	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.	Final Decision	ISO recommendation was adopted as posted.
Accept	57	Changed language to say if needed the ISO will host additional public meetings to discuss the results from the PTOs.	Final Decision	ISO recommendation was adopted.
Accept	58	Modified/reorganized language regarding Stage 3 output.	Final Decision	ISO recommendation was adopted as posted.
Accept	59	Request Window submissions can be approved by ISO Executive Management during Stage 3, from November through February, under certain circumstances.	Final Decision	ISO recommendation was adopted.
Accept	60	Projects with an estimated capital investment of less than $50 million that are approved by ISO Executive Management will receive approval letter.	Final Decision	ISO recommendation was adopted.
Accept	61	Language modification to clarify Transmission Plan designation.	Final Decision	No comments were received on this PRR 61 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This change is effective when the PRR process is complete.
Accept	62	Section 2.2.1 clarification and reorganization	Final Decision	ISO recommendation was adopted as posted.

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	63	Amending the Transmission Plan	Final Decision	ISO recommendation was adopted as posted.
Accept	64	Adds section heading for existing BPM language	Final Decision	ISO recommendation was adopted as posted.
Accept	65	Modifications to language describing Economic Planning Studies	Final Decision	ISO recommendation was adopted as posted.
Accept	66	Modifications to the Secondary Validation Response Period.	Final Decision	ISO recommendation was adopted as posted.
Accept	67	Information to be submitted with Request Window proposals to include generation in the TPP study process.	Final Decision	ISO recommendation was adopted as posted.
Accept	68	Circumstance under which projects will be recommended for ISO Board of Governors approval	Final Decision	ISO recommendation was adopted as posted.
Accept	69	Non-substantive modification of Large Project description	Final Decision	No comments were received on this PRR 69 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This change is effective when the PRR process is complete.
Accept	70	Large Project non-approval notification process	Final Decision	ISO recommendation was adopted as posted.
Accept	71	Non-approval notification process for projects other than Large Projects	Final Decision	No comments were received on this PRR 71 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This change is effective when the PRR process is complete.

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Reject	72	Definition of Maintenance Projects	Final Decision	After stakeholder discussion, the ISO recommends this issue be addressed in a separate stakeholder process and to not make any changes to the BPM at this time.
Accept	73	Communicate FNM updates to WECC	Final Decision	No comments were received on this PRR 73 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This PRR will be effective with DB45.
Accept	74	Revisions for Payment Acceleration	Final Decision	The ISO adopts the recommendation as submitted. No comments received during open comment period.
Accept	75	Revisions to the BPM for Credit Management to reflect changes resulting from Payment Acceleration	Final Decision	No comments were received on this PRR 75 and the PRR is a category A. These two criteria allow for the PRR to move directly to the final decision stage. The ISO's final decision on this PRR is to adopt the language as initially proposed. This change will be effective with implementation of Payment Acceleration or 11/1/09.
Accept	76	Detailed NERC Reliability Assessment Studies	Final Decision	ISO recommendation was adopted.
Accept	77	Edits to incorporate Payment Acceleration principles, changes to Historic Rerun PTB amount presentation, and other content clarification edits.	Final Decision	BPM PRR 77 Final Decision Details October 5, 2009 During the 9/22 BPM Stakeholder meeting it was announced that the recent FERC Order on Payment Acceleration may require additional changes to the BPM for Settlements and Billing (main body). Furthermore, it was stated that this PRR would be held open at least until a compliance filing occurred and at that point a second recommendation period would open. After

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Final Decisions Posted – 8/20/09 to 10/12/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				additional consideration, the ISO has instead decided to move this PRR forward in the process and adopt the change as proposed in the recommendation as the Final Decision. This includes the additional edits as shown in the revised draft which provide clarifying language on the Bill Period for initial statements and additional details on the dispute process (in section 5.5) in response to participant comments, as well as the specifics detailed in the Attachment B Charge Group and Parent Charge Group Specification attached to this PRR. The direction is being changed to ensure the other edits captured in this PRR that are unrelated to Payment Acceleration complete the BPM change management process. Should the need for additional edits arise as a result of the compliance filing, a new PRR will be created.
Accept	78	New Expected Energy Calculation schedule effective with Payment Acceleration	Final Decision	The ISO recommendation which was posted for this PRR is being adopted without any change. Section C.6 of appendix C of Market operations BPM will be updated with the proposed language. Please see attached document for the final language.
Accept	81	Update Reliability Requirements BPM Exhibit A-2 with due dates for 2010 submittals	Final Decision	The ISO adopts the recommendation as submitted and the decision is currently effective.

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	118	Update BPM Configuration Guide for CC 6636 IFM Bid Cost Recovery Tier 1 Allocation to reflect actual calculation of Total IFM Load Uplift Obligation Trades To	BPM Configuration Guide for CC 6636 IFM Bid Cost Recovery Tier 1 Allocation	A	10/6/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	117	Update the BPM document to be consistent with current configuration and in response to Participant issue ticket	CG CC 4505 GMC - Energy Transmission Services Net Energy.doc	A	10/6/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	116	Update BPM Configuration Guide for CC 6620 Bid Cost Recovery Settlement to correct typographical error.	BPM Configuration Guide for CC 6620 Bid Cost Recovery Settlement	A	10/6/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	115	Update BPM Configuration guide for CC 6798 for payment acceleration	CG CC 6798 CRR Auction Transaction Settlement	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	114	New BPM Configuration guide for CC 6791 for payment acceleration	CG CC 6791 CRRBA Accrued Interest Allocation	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	113	Update BPM Configuration guide for CC 6790 for payment acceleration	CG CC 6790 CRR Balancing Account	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	112	Termination of BPM Configuration guide for CC 6728	CG CC 6728 CRR Monthly Clearing	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	111	Update BPM Configuration guide for CC 6700 to eliminate hourly pro-ration and related charge types, and update charge code description for payment acceleration changes	CG CC 6700 CRR Hourly Settlement	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	110	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources (PIR) under Payment Acceleration.	BPM Configuration Guide for Charge Code 6486 Real Time Excess Cost for Instructed Energy Allocation	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants' systems.
Category C - Significant new ISO policies and/or revisions to the ISO 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	109	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources (PIR) under Payment Acceleration.	BPM Configuration Guide for Charge Code 6480 Excess Cost Neutrality Allocation	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	108	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources Program (PIRP) in CC 6477 under Payment Acceleration.	BPM Configuration Guide for Charge Code 6477 Real Time Imbalance Energy Offset	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	107	Update the BPM document and Configuration to reflect new PIRP charge code in the Participating Intermittent Resources charge group	CG CC 4999 Monthly Rounding Adjustment Allocation	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	106	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources Program (PIRP) under Payment Acceleration.	BPM Configuration Guide for Charge Code 6475 Real Time Uninstructed Imbalance Energy Settlement	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	105	New Charge Code 722 for Participating Intermittent Resources Program (PIRP) required as a result of Payment Acceleration	BPM Configuration Guide for Charge Code 722 Intermittent Resources Net Deviation Reversal	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Market Operations	104	Revisions to ensure consistency with RMR contract and tariff requirements	Section 6.5.1 and Section 6.5.2	A	10/6/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	103	Update the BPM Configuration Guide for CC 6477 to accommodate tariff language changes in section 11.5.4.2 regarding allocation changes for Load Following MSS entities	CG CC 6477 Real Time Imbalance Energy Offset	B	9/30/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	102	Update BPM Configuration Guide for Start Up and Minimum Load Cost to accommodate implementation defect for Pumping Cost sign convention	BPM Configuration Guide for Start-Up and Minimum Load Cost Pre-calculation	B	9/30/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants’ systems.
Category C - Significant new ISO policies and/or revisions to the ISO 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
Market Operations	101	Changes to reflect enforcement of capacity based nomograms in RUC.	New section created for this information: 6.7.2.4.8. Also, changes are proposed to section 3.1.7 in this PRR.	B	9/30/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Market Operations	100	Market Operations BPM changes due to Simplified ramping rules implementation	Section 6.6.2 and Section 7.6.3.2	B	9/30/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Credit Management	99	Inconsistent Use of Minimum/Maximum Days; Lack of explanation of how days are determined	Section 4.1, Section 6.2	A	9/23/2009	PG&E	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	98	New Charge Code 8827 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8827 Monthly NRSS Resource Adequacy Standard Capacity Product MD Allocation	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	97	New Charge Code 8826 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8826 Monthly Resource Adequacy Standard Capacity Product MD Allocation	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	96	New Charge Code 8825 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8825 Monthly NRSS Resource Adequacy Standard Capacity Product Settlement	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants’ systems.
Category C - Significant new ISO policies and/or revisions to the ISO 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	95	New Charge Code 8824 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8824 Monthly Resource Adequacy Standard Capacity Product Settlement	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	94	New Charge Code 8821 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8821 Monthly NRSS Resource Adequacy Standard Capacity Product Allocation	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	93	New Charge Code 8820 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8820 Monthly Resource Adequacy Standard Capacity Product Allocation	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	92	New Pre-calculation required for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Standard Capacity Product Pre-calculation	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	91	Update Settlements & Billing BPM Main Body for new subscript associated with Standard Capacity Product (SCP) Charge Codes	Settlements & Billing BPM Main Body section 8.2.2 Subscript Conventions, Exhibit 8-2	B	9/16/2009	California ISO	Normal	Comment Period	Final Decision
Reliability Requirements	90	Update Reliability Requirement BPM Supply Plan Content rules	4.2 Content	A	9/16/2009	CAISO	Normal	Comment Period	Final Decision
Reliability Requirements	89	New section for Standard Capacity Product	Section 8 Standard Capacity Product	B	9/8/2009	CAISO	Normal	Comment Period	Final Decision
Market Instruments	88	Standard Capacity and Ancillary Services Must Offer Obligation (MOO)	Ancillary Services and RUC; Sections 6 and 7	A	9/4/2009	California ISO	Normal	Comment Period	Final Decision

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants' systems.
Category C - Significant new ISO policies and/or revisions to the ISO 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
Outage Management	87	Revisions due to Standard Capacity Product	5.1 and addition of section 7.3.1 to 7.3	B	9/4/2009	CAISO	Normal	Comment Period	Final Decision
Market Operations	86	Changes to Market Operation BPM arising from Standard Capacity Product	Section 6.6.3 of the BPM	A	9/4/2009	California ISO	Normal	Comment Period	Final Decision
Settlements and Billing	85	New BPM Configuration guide for CC 692 Start-Up Cost Payment	Charge Code CC 692 Start-Up Cost Payment	B	9/2/2009	California ISO	Emergency	Comment Period	Final Decision
Settlements and Billing	84	Update BPM Configuration guide for CC 7879 to define new language for Exceptional Dispatch ICPM and to replace the currently specified PTB allocation with a newly defined monthly calculation performed within the CC 7879 configuration	Charge Code CC 7879 Monthly Significant Event ICPM Allocation	B	9/2/2009	California ISO	Emergency	Comment Period	Final Decision
Settlements and Billing	83	Update BPM Configuration guide for Measured Demand over Control Area pre-calculation to include Metered Demand output variables for use with the CC7879 Monthly Significant Event ICPM Allocation configuration.	Pre-calculation Measured Demand over Control Area	B	8/26/2009	CAISO	Emergency	Comment Period	Final Decision
Reliability Requirements	81	Update Reliability Requirements BPM Exhibit A-2 with due dates for 2010 submittals	Exhibit A-2	A	8/19/2009	CAISO	Emergency	Final Decision	NA
Settlements and Billing	80	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	Final Decision
Metering	79	Metering BPM update to reflect Payment Acceleration implementation	1.2 to 10.8 (see breakdown in Additional Qualitative Information)	A	8/7/2009	CAISO	Normal	Comment Period	Final Decision
Market Operations	78	New Expected Energy Calculation schedule effective with Payment Acceleration	Appendix C Section C.6	A	8/7/2009	California ISO	Normal	Final Decision	NA

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants' systems.
Category C - Significant new ISO policies and/or revisions to the ISO 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	77	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	California ISO	Normal	Final Decision	NA
Transmission Planning Process	76	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	California ISO	Normal	Final Decision	NA
Credit Management	75	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	California ISO	Normal	Process Complete	NA
Rules of Conduct	74	Revisions for Payment Acceleration	various	A	8/7/2009	California ISO	Normal	Final Decision	NA
Managing Full Network Model	73	Communicate FNM updates to WECC	5.1.2 FNM Data Gathering	A	8/5/2009	CAISO	Normal	Process Complete	NA
Transmission Planning Process	72	Definition of Maintenance Projects	3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	71	Non-approval notification process for projects other than Large Projects	New section titled: 4.3.3 Rejection Process	A	8/5/2009	CAISO	Normal	Process Complete	NA
Transmission Planning Process	70	Large Project non-approval notification process	4.3.2 Large Project Evaluations	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	69	Non-substantive modification of Large Project description	4.3.1 Timeframe for Project Approvals	A	8/5/2009	CAISO	Normal	Process Complete	NA
Transmission Planning Process	68	Circumstance under which projects will be recommended for ISO Board of Governors approval	4.3.1 Timeframe for Project Approvals	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	67	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	CAISO	Normal	Final Decision	NA

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants' systems.
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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	66	Modifications to the Secondary Validation Response Period.	3.2 Request Window Submission Process	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	65	Modifications to language describing Economic Planning Studies	3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	64	Adds section heading for existing BPM language	New section titled: 2.2.3 Compliance with NERC Reliability Standards	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	63	Amending the Transmission Plan	A. New section: 2.2.2 & B. 4.3.4	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	62	Section 2.2.1 clarification and reorganization	New section titled: 2.2.1 Contents of the Transmission Plan	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	61	Language modification to clarify Transmission Plan designation.	2.2 ISO Transmission Plan	A	8/5/2009	CAISO	Normal	Process Complete	NA
Transmission Planning Process	60	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	CAISO	Normal	Final Decision	NA
Transmission Planning Process	59	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	CAISO	Normal	Final Decision	NA
Transmission Planning Process	58	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	CAISO	Normal	Final Decision	NA
Transmission Planning Process	57	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	CAISO	Normal	Final Decision	NA

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants’ systems.
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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	56	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	CAISO	Normal	Final Decision	NA
Transmission Planning Process	55	Categories of Request Window Submissions	2.1.2.1 Request Window	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	54	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	CAISO	Normal	Process Complete	NA
Transmission Planning Process	53	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	CAISO	Normal	Final Decision	NA
Transmission Planning Process	52	General Description of Request Window Categories	2.1.2.1 Request Window	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	51	The NERC Reliability criteria violation recommended solution	A. 2.1.1.2 B. 4.2	A	8/5/2009	CAISO	Normal	Final Decision	NA
Transmission Planning Process	50	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	CAISO	Normal	Final Decision	NA
Transmission Planning Process	49	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	CAISO	Normal	Final Decision	NA

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants’ systems.
Category C - Significant new ISO policies and/or revisions to the ISO 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	48	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	California ISO	Emergency	Final Decision	NA
Settlements and Billing	47	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	California ISO	Emergency	Final Decision	NA
Managing Full Network Model	46	FNM Update Process Flow Digaram - Update	5.1 - Exhibit 5.1	A	8/5/2009	CAISO	Normal	Process Complete	NA
Settlements and Billing	45	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	California ISO	Emergency	Final Decision	NA
Settlements and Billing	44	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	Final Decision	NA
Settlements and Billing	43	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	CAISO	Emergency	Process Complete	NA
Settlements and Billing	42	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	CAISO	Emergency	Process Complete	NA

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
Settlements and Billing	41	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	CAISO	Emergency	Process Complete	NA
Market Operations	39	New Expected Energy Types	Appendix C Section C.4.1	B	7/8/2009	California ISO	Urgent	Process Complete	NA
Market Instruments	38	Master File Update (User Interface)	Appendix B Master File Update Procedures	B	7/8/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	37	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	36	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	35	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	34	New BPM Configuration Guide for CC 7989 effective with Payment Acceleration	BPM Configuation Guide for Charge Code 7989 Invoice Deviation Interest Distribution	C	6/24/2009	California ISO	Normal	Process Complete	NA

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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
Compliance Monitoring	33	Dispatchable RUC Capacity	Section 7.2 Rescission of Payments for Undispatchable RUC Capacity for Generating Units, & Dynamic System Resources	B	6/24/2009	CAISO	Emergency	Process Complete	NA
Market Operations	32	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	Process Complete	NA
Market Operations	31	Clarification on transmission interface constraints modeling in market software	BPM Sections Requiring 3.2.4	A	6/17/2009	Southern California Edison	Normal	Process Complete	NA
Settlements and Billing	30	Update the BPM Configuration Guide for CC 4503 to reflect attribute changes for BASettlementIntervalBalancedTORExportEnergyQuantity	CG CC 4503 GMC CRS Export	B	6/11/2009	CAISO	Emergency	Process Complete	NA
Settlements and Billing	29	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	CAISO	Emergency	Process Complete	NA
Settlements and Billing	28	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	CAISO	Emergency	Process Complete	NA
Settlements and Billing	27	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	CAISO	Emergency	Process Complete	NA
Settlements and Billing	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.	Pre-calculation Measured Demand over Control Area	B	6/11/2009	CAISO	Emergency	Process Complete	NA

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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
Settlements and Billing	25	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	CAISO	Emergency	Process Complete	NA
Settlements and Billing	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.	IFM Net Amount Pre-calculation	B	6/10/2009	CAISO	Emergency	Process Complete	NA
Settlements and Billing	23	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	22	Formula Change to CC 6700 Section 3.6.1.2	CC 6700 -CRR Hourly Settlement	B	6/3/2009	Pacific Gas & Electric	Urgent	Process Complete	NA
Settlements and Billing	21	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	20	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	19	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	CAISO	Emergency	Process Complete	NA
Settlements and Billing	18	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	CAISO	Emergency	Process Complete	NA
Congestion Revenue Rights	17	Global Derating Factor for CRRs	10.3.3	A	5/20/2009	Southern California Edison	Normal	Process Complete	NA

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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
Settlements and Billing	16	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	California ISO	Emergency	Process Complete	NA
Rules of Conduct	15	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	CAISO	Normal	Process Complete	NA
Market Operations	14	Detailing Treatment of Start-Up Costs in Day-Ahead IFM Optimization	6.6	A	4/29/2009	Dynegy	Normal	Process Complete	NA

Category A - Language, grammatical errors and/or minimal impact.
Category B - Significant changes to existing ISO or Market Participants' systems.
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Business Practice Manuals
Change Management Report
December 9, 2009

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Karen Edson, Vice President, Policy & Client Services

Date: December 9, 2009

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

This memorandum does not require Board action.

EXECUTIVE SUMMARY

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

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 the BPM Appeals Committee, which is comprised of three ISO officers.

As of November 20, 2009, 51 proposed revision requests (PRRs) were active in the BPM change management system, 96% of which were submitted by the ISO. These 51 active PRRs impact the following BPMs:

37	Settlements and Billing
4	Market Operations
2	Reliability Requirements
1	Credit Management
1	Market Instruments
1	Metering
1	Outage Management
4	Definitions and Acronyms

No BPM decisions are under stakeholder appeal.

PROCESS OVERVIEW

The ISO held the monthly BPM change management stakeholder meeting on October 27, 2009. The meeting, which was conducted by conference call, included 16 stakeholders. Based on the nature of that meeting, and upon the types of comments entered into the BPM change management electronic system, it appears that stakeholders are generally satisfied with the process, as well as with the progress made on the active PRRs. No significant concerns are currently pending on the active PRRs.

BPM CHANGE MANAGEMENT REPORT

The current *Board Update: BPM Change Management Process* report, which includes all the active PRRs as of November 20, 2009, is included as Attachment 1. In compliance with the tariff Board reporting requirements, the report:

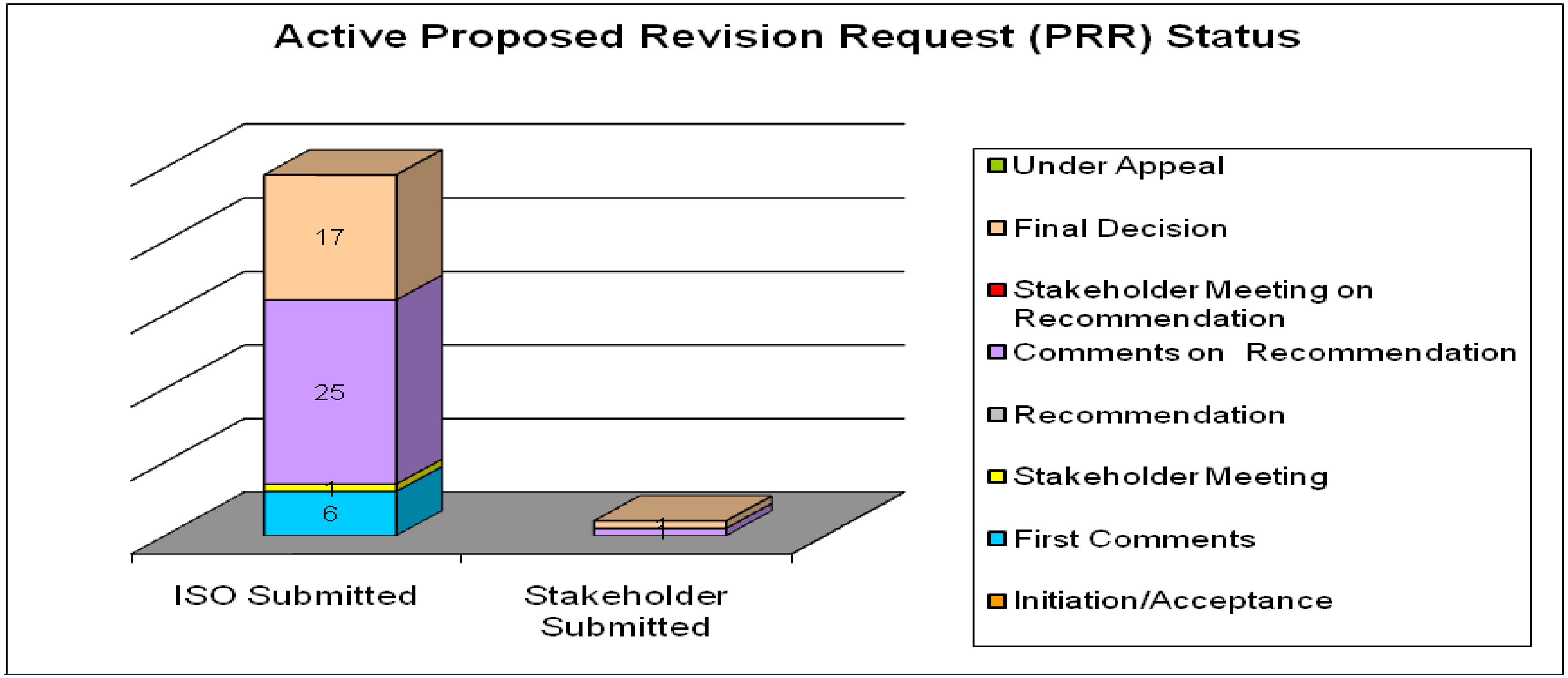
- Summarizes the total number of active PRRs submitted by stakeholders and by the ISO;
- Depicts the number of active PRRs in various steps along the PRR lifecycle, as of November 20, 2009;
- Reflects those PRRs upon which Management has posted its final decision for the period October 13, 2009 through November 20, 2009; and
- Includes PRRs currently under stakeholder appeal, the stakeholder positions on rejected PRRs, and the reasons for rejection.

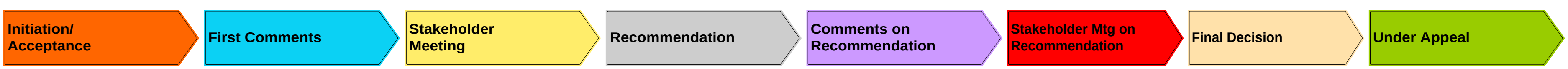
The following is additional relevant information:

- No PRRs are under appeal; PRR 44 was under appeal during this period. However, Citigroup Energy, Inc. withdrew its appeal before the public meeting.
- Seven of the active PRRs were submitted into the electronic system by the ISO on an emergency basis and all of those PRRs are related to the Settlements and Billing BPM.
- A PRR report summarizing the PRRs in the BPM change management system as of December 1, 2009, is included as Attachment 2.

Board Update: BPM Change Management Process
December 16, 2009 Board Meeting

Attachment 1





Active PRR Stage	# of PRRs
First Comments	6
Stakeholder Meeting	1
Comments on Recommendation	26
Final Decision	18
Total	**51**

Business Practice Manual (BPM)	# of PRRs
Credit Management	1
Definitions and Acronyms	4
Market Instruments	1
Market Operations	4
Metering	1
Outage Management	1
Reliability Requirements	2
Settlements and Billing	37
Total	**51**

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	79	Metering BPM update to reflect Payment Acceleration implementation	Final Decision	The ISO adopts its recommendation as submitted. No comments were received.
Reject	80	Formula changes to section 3.6.1 and 3.6.2	Final Decision	As no comments were received, the ISO is adopting the recommendation to reject the change requested in this PRR. The reason for rejecting the PRR follows: The ISO recommends rejecting the BPM revisions as submitted in the BPM PRR because unlike a programming language such as PL/SQL, CAISO settlement software permits division by zero. The operation does not create a fatal error, but instead a value of zero is returned. Therefore, in cases where the awarded energy above Minimum Load and Self-Schedule is zero, then Metered Energy Adjustment Factor is not applicable and set to zero accordingly.
Accept	83	Update BPM Configuration guide for Measured Demand over Control Area pre-calculation to include Metered Demand output variables for use with the CC7879 Monthly Significant Event ICPM Allocation configuration.	Final Decision	As no further comments were received, the ISO is adopting the recommendation as proposed.
Accept	84	Update BPM Configuration guide for CC 7879 to define new language for Exceptional Dispatch ICPM and to replace the currently specified PTB allocation with a newly defined monthly calculation performed within the CC 7879 configuration	Final Decision	As no additional comments were received, the ISO is adopting the recommendation as proposed.
Accept	85	New BPM Configuration guide for CC 692 Start-Up Cost Payment	Final Decision	As no additional comments were received, the ISO is adopting the recommendation as proposed.

California ISO
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Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	86	Changes to Market Operation BPM arising from Standard Capacity Product	Final Decision	CAISO's final decision on this PRR is to adopt the original language proposed in the PRR without any change. The change proposed in the stakeholder comment is not necessary as availability is always understood as operational availability (no outage) and market availability (bids) as opposed to being online. A resource can be made available and still be offline simply because its bid was not taken, or because it was selected to provide non-spin from offline state.
Accept	87	Revisions due to Standard Capacity Product	Final Decision	Outage management BPM Section 7.3.1 Resource Adequacy Outage Reporting has been added to CAISO Operating Procedure T-113 in section 13.1. This addition is in reference to forced outage reporting for RA resources between 1 and 10 MW. A minor change from the initial PRR 87 has been made. Rather than adding a new attachment "U" to the procedure the reporting requirement is now located in the body of T-113 in section 13.1 . Final Decision: 7.3.1 Resource Adequacy Resources with Pmax Between 1.0 MW and 10 MW CAISO Tariff Section 40.9.5 CAISO Tariff Section 40.9.5 requires Resource Adequacy Resources with a Pmax between 1.0 MW and 10 MW that are not required to report Forced Outages within 60 minutes of discovery to provide equivalent availability-related information at the end of the calendar month. Such resources must use the SLIC Web-Client to report all Forced Outages or de-rates and temperature-related ambient de-rates.

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				Resource Adequacy Resources with a Pmax between 1.0 and 10 MW are not required to report their availability near real-time, but must provide Forced Outages or de-rates and temperature-related ambient de-rates no later than 3 business days after the end of the calendar month. Operating Procedure T-113, Scheduled and Forced Outages, section 13.1 Immediate Forced Outages or Derates, RA Resources provides details on how Resource Adequacy Resources with a Pmax between 1.0 MW and 10 MW should report availability. These Resource Adequacy Resources are subject to Non-Availability Charges and Availability Incentive Payments as described in Section 40.9.6 of the CAISO Tariff and Section 8 of the BPM for Reliability Requirements.
Accept	88	Standard Capacity and Ancillary Services Must Offer Obligation (MOO)	Final Decision	After consideration of the stakeholder comments received, the ISO adopts its recommendation as submitted.

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	89	New section for Standard Capacity Product	Final Decision	Adopt Recommendation with some minor modifications: 1. Formula correction to Section 8.4.1. 2. Additional clarification added to Section 8.7.2 due to comments from Mohan Niroula on Oct 19. 3. Section 8.7.2 the Operating Procedure for Unit Substitution is G-204. 4. Section 8.4.2.1 submittals for out-of-service transmission path will be handled through the SLIC application instead of a manual template. 5. Added Section 8.7.3 for unit substitution for non-Local resources. 6. Change wording of new attribute for use limit reached in Section 8.4.1.2 7. Add obligation to bid RA RUC to Section 8.7 8. Updated Tariff references to conform with Updated Tariff as of Oct 8, 2009.
Accept	90	Update Reliability Requirement BPM Supply Plan Content rules	Final Decision	The ISO adopts its Recommendation as submitted on PRR 90.
Accept	90	Update Reliability Requirement BPM Supply Plan Content rules	Final Decision	The ISO adopts its Recommendation as submitted.

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	91	Update Settlements & Billing BPM Main Body for new subscript associated with Standard Capacity Product (SCP) Charge Codes	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation. Due to holiday time, the ISO allowed late comments from SCE on PRR 91. Those comments and ISO responses are provided as follows: 1. When will the Settlements Main Body BPM be updated to reflect the changes for Payment Acceleration (PA) and Standard Capacity Product (SCP)? CAISO RESPONSE: The Settlements Main Body BPM has already been updated to reflect the changes for PA and SCP. Please see the BPM Library or PRR 77 for the updated version for Payment Acceleration. The only change in the main body related to SCP is in section 8.2 which are detailed in full within PRR 91. 2. The new SCP subscript "contract #" for Grandfathered Contracts - since there may be multiple Grandfathered Contracts for the same RA resource, CAISO should ensure that this number is unique and can be traced back to the RA Supply Plan Contract Number. CAISO RESPONSE: Providing a unique number is the exact intent of this subscript.

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
Accept	92	New Pre-calculation required for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation plus additional edits communicated during the October 27 BPM Stakeholder Meeting. This update is the result of an upstream system requirement change that allows Market participants to substitute in Real Time without being penalized. The updated configuration guide, edit version dated 10/26/09 is provided as an attachment to this Final Decision.
Accept	93	New Charge Code 8820 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	Final Decision	As no additional comments were received, the ISO is adopting the recommendation as proposed
Accept	94	New Charge Code 8821 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	Final Decision	As no additional comments were received, the ISO is adopting the recommendation as proposed.
Accept	95	New Charge Code 8824 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	Final Decision	As no additional comments were received, the ISO is adopted the recommendation as proposed
Accept	96	New Charge Code 8825 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	Final Decision	As no additional comments received, the ISO is adopting the recommendation as proposed.
Accept	97	New Charge Code 8826 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation. Due to holiday time, the ISO allowed late comments from SCE on PRR 97. Those comments and ISO responses are provided as follows:

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				SCE QUESTION: Section 3.6.2 contains a minor typo where CAISO states that HourlyNodalMeteredCAISODemandQuantity_MDOverCAAA?mdh is provided by the monthly summation process(which is a view that adds together all daily calculation amounts from daily settlement runs into monthly totals used for monthly settlement calculations) where I believe they mean that MonthlyNodalMeteredCAISODemandQuantity_MDOverCA m is the one provided by the process. CAISO RESPONSE: SCE is correct that output is the Monthly value, however Section 3.6.2 as written intends to show the calculation performed by the view, rather than simply output provided in order to provide transparency to participants. The sentence reads as: ? the summation of attribute A, A?, d, and h of the HourlyNodalMeteredCAISODemandQuantity_MDOverCA is provided by the configuration enhancement procedure that returns a monthly quantity as a summation of daily quantities generated previously calculated under Measured Demand Precalc during daily settlement calculation results for the applicable Trading Month? The resulting monthly quantity provided as output is represented by the bill determinant MonthlyNodalMeteredCAISODemandQuantity_MDOverCA.
Accept	98	New Charge Code 8827 for Resource Adequacy Standard Capacity Product	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.

Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
		(SCP) effective as of 01/01/2010		Due to holiday time, the ISO allowed late comments from SCE on PRR 98. Those comments and ISO responses are provided as follows: SCE QUESTION: Section 3.6.2 contains a minor typo where CAISO states that HourlyNodalMeteredCAISODemandQuantity_MDOverCAAA mdh is provided by the monthly summation process(which is a view that adds together all daily calculation amounts from daily settlement runs into monthly totals used for monthly settlement calculations) where I believe they mean that MonthlyNodalMeteredCAISODemandQuantity_MDOverCA m is the one provided by the process. CAISO RESPONSE: SCE is correct that output is the Monthly value, however Section 3.6.2 as written intends to show the calculation performed by the view, rather than simply output provided in order to provide transparency to participants. The sentence reads as: "the summation of attribute A, A", d, and h of the HourlyNodalMeteredCAISODemandQuantity_MDOverCA is provided by the configuration enhancement procedure that returns a monthly quantity as a summation of daily quantities generated previously calculated under Measured Demand Precalc during daily settlement calculation results for the applicable Trading Month? The resulting monthly quantity provided as output is represented by the bill determinant

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Final Decisions Posted – 10/13/09 to 11/20/09

Accept or Reject	PRR Number	PRR Title	Current PRR Status	Final Decision Text
				MonthlyNodalMeteredCAISODemandQuantity_MDOverCA.

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	132	Market Operations BPM Updates related to PIRP	Remove Section A.5 from Appendix A and add a new section at the end of Appendix A	C	11/25/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	131	Update the BPM Configuration Guide for rounding Charge Code 4999 to reflect the addition of Declined HASP Bids charge group to the monthly rounding calculation	CG CC 4999 Monthly Rounding Adjustment Allocation.	B	11/18/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	130	Update BPM Configuration guide for Measured Demand over Control Area pre-calculation to include Metered Demand output variables for use with the CC 6457 Declined Hourly Pre-Dispatch Penalty Allocation configuration.	Pre-calculation Measured Demand over Control Area	B	11/18/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	129	Update the BPM Configuration Guide for Real Time Energy Pre-calculation to reflect new successor Charge Code and ensure consistency with configuration.	BPM Configuration Guide Real Time Energy Quantity Pre-calculation	A	11/18/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	128	Introduce BPM Configuration guide for the new settlements Charge Code 6457 Declined Hourly Pre-Dispatch Penalty Allocation configuration.	CC 6457 Declined Hourly Pre-Dispatch Penalty Allocation	B	11/18/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	127	Introduce BPM Configuration Guide for the new settlements Charge Code 6455 Declined Hourly Pre-Dispatch Penalty Settlement configuration	CC 6455 Declined Hourly Pre-Dispatch Penalty Settlement	B	11/18/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	126	Update the BPM and Configuration for CC 4537 to reflect the new tariff requirements for calculating the Billable Quantity.	CC 4537 GMC Market Usage Forward Energy	B	11/11/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	125	Update the BPM document for CC 4999 and Configuration to reflect the addition of Standard Capacity Product (SCP) charge groups to the monthly rounding calculation	CG CC 4999 Monthly Rounding Adjustment Allocation	B	10/29/2009	California ISO	Normal	Recommendation	Comments on Recommendation

Category A - Language, grammatical errors or minimal impact.
Category B - Significant changes to existing ISO or Market Participants' systems.
Category C - Significant new ISO 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
Definitions and Acronyms	124	Update to Definitions to Incorporate Pending CAISO Tariff Revisions	No Section, only definitions	A	10/14/2009	California ISO	Normal	Decision Review	Final Decision
Definitions and Acronyms	123	Update to Definitions to Incorporate CAISO Tariff Revisions Regarding Standard Capacity Product	No Section, only definitions	A	10/14/2009	California ISO	Normal	Decision Review	Final Decision
Definitions and Acronyms	122	Update to Definitions to Incorporate CAISO Tariff Revisions Regarding Payment Acceleration	No Section, only definitions	A	10/14/2009	California ISO	Normal	Decision Review	Final Decision
Definitions and Acronyms	121	Update to Definitions to Incorporate Already-Effective CAISO Tariff Revisions	No Section, only definitions	A	10/14/2009	California ISO	Normal	Decision Review	Final Decision
Settlements and Billing	120	Update BPM Configuration guide for CC 383 Low Voltage Wheeling Allocation to accommodate Wheeling Non-PTO data submittal - Payment Acceleration	CC 383 Low Voltage Wheeling Allocation	A	10/14/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	119	Update BPM Configuration guide for CC 382 High Voltage Wheeling Allocation to accommodate Wheeling Non-PTO data submittal - Payment Acceleration	CC 382 High Voltage Wheeling Allocation	A	10/14/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	118	Update BPM Configuration Guide for CC 6636 IFM Bid Cost Recovery Tier 1 Allocation to reflect actual calculation of Total IFM Load Uplift Obligation Trades To	BPM Configuration Guide for CC 6636 IFM Bid Cost Recovery Tier 1 Allocation	A	10/6/2009	California ISO	Normal	Decision Review	Final Decision
Settlements and Billing	117	Update the BPM document to be consistent with current configuration and in response to Participant issue ticket	CG CC 4505 GMC - Energy Transmission Services Net Energy.doc	A	10/6/2009	California ISO	Normal	Decision Review	Final Decision
Settlements and Billing	116	Update BPM Configuration Guide for CC 6620 Bid Cost Recovery Settlement to correct typographical error.	BPM Configuration Guide for CC 6620 Bid Cost Recovery Settlement	A	10/6/2009	California ISO	Normal	Decision Review	Final Decision
Settlements and Billing	115	Update BPM Configuration guide for CC 6798 for payment acceleration	CG CC 6798 CRR Auction Transaction Settlement	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	114	New BPM Configuration guide for CC 6791 for payment acceleration	CG CC 6791 CRRBA Accrued Interest Allocation	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	113	Update BPM Configuration guide for CC 6790 for payment acceleration	CG CC 6790 CRR Balancing Account	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision

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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	112	Termination of BPM Configuration guide for CC 6728	CG CC 6728 CRR Monthly Clearing	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	111	Update BPM Configuration guide for CC 6700 to eliminate hourly pro-ration and related charge types, and update charge code description for payment acceleration changes	CG CC 6700 CRR Hourly Settlement	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	110	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources (PIR) under Payment Acceleration.	BPM Configuration Guide for Charge Code 6486 Real Time Excess Cost for Instructed Energy Allocation	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	109	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources (PIR) under Payment Acceleration.	BPM Configuration Guide for Charge Code 6480 Excess Cost Neutrality Allocation	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	108	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources Program (PIRP) in CC 6477 under Payment Acceleration.	BPM Configuration Guide for Charge Code 6477 Real Time Imbalance Energy Offset	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	107	Update the BPM document and Configuration to reflect new PIRP charge code in the Participating Intermittent Resources charge group	CG CC 4999 Monthly Rounding Adjustment Allocation	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	106	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources Program (PIRP) under Payment Acceleration.	BPM Configuration Guide for Charge Code 6475 Real Time Uninstructed Imbalance Energy Settlement	B	10/6/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	105	New Charge Code 722 for Participating Intermittent Resources Program (PIRP) required as a result of Payment Acceleration	BPM Configuration Guide for Charge Code 722 Intermittent Resources Net Deviation Reversal	B	10/6/2009	California ISO	Emergency	Decision Review	Final Decision

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BPM Proposed Revision Requests (PRR): Summary Report

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Market Operations	104	Revisions to ensure consistency with RMR contract and tariff requirements	Section 6.5.1 and Section 6.5.2	A	10/6/2009	California ISO	Normal	Decision Review	Final Decision
Settlements and Billing	103	Update the BPM Configuration Guide for CC 6477 to accommodate tariff language changes in section 11.5.4.2 regarding allocation changes for Load Following MSS entities	CG CC 6477 Real Time Imbalance Energy Offset	B	9/30/2009	California ISO	Emergency	Decision Review	Final Decision
Settlements and Billing	102	Update BPM Configuration Guide for Start Up and Minimum Load Cost to accommodate implementation defect for Pumping Cost sign convention	BPM Configuration Guide for Start-Up and Minimum Load Cost Pre-calculation	B	9/30/2009	California ISO	Emergency	Decision Review	Final Decision
Market Operations	100	Market Operations BPM changes due to Simplified ramping rules implementation	Section 6.6.2 and Section 7.6.3.2	B	9/30/2009	California ISO	Normal	Decision Review	Final Decision
Credit Management	99	Inconsistent Use of Minimum/Maximum Days; Lack of explanation of how days are determined	Section 4.1, Section 6.2	A	9/23/2009	PG&E	Normal	Decision Review	Final Decision
Settlements and Billing	98	New Charge Code 8827 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8827 Monthly NRSS Resource Adequacy Standard Capacity Product MD Allocation	B	9/16/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	97	New Charge Code 8826 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8826 Monthly Resource Adequacy Standard Capacity Product MD Allocation	B	9/16/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	96	New Charge Code 8825 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8825 Monthly NRSS Resource Adequacy Standard Capacity Product Settlement	B	9/16/2009	California ISO	Normal	Process Complete	NA

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BPM Proposed Revision Requests (PRR): Summary Report

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Settlements and Billing	95	New Charge Code 8824 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8824 Monthly Resource Adequacy Standard Capacity Product Settlement	B	9/16/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	94	New Charge Code 8821 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8821 Monthly NRSS Resource Adequacy Standard Capacity Product Allocation	B	9/16/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	93	New Charge Code 8820 for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Charge Code 8820 Monthly Resource Adequacy Standard Capacity Product Allocation	B	9/16/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	92	New Pre-calculation required for Resource Adequacy Standard Capacity Product (SCP) effective as of 01/01/2010	BPM Configuration Guide for Standard Capacity Product Pre-calculation	B	9/16/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	91	Update Settlements & Billing BPM Main Body for new subscript associated with Standard Capacity Product (SCP) Charge Codes	Settlements & Billing BPM Main Body section 8.2.2 Subscript Conventions, Exhibit 8-2	B	9/16/2009	California ISO	Normal	Process Complete	NA
Reliability Requirements	90	Update Reliability Requirement BPM Supply Plan Content rules	4.2 Content	A	9/16/2009	California ISO	Normal	Process Complete	NA
Reliability Requirements	89	New section for Standard Capacity Product	Section 8 Standard Capacity Product	B	9/8/2009	California ISO	Normal	Process Complete	NA
Market Instruments	88	Standard Capacity and Ancillary Services Must Offer Obligation (MOO)	Ancillary Services and RUC; Sections 6 and 7	A	9/4/2009	California ISO	Normal	Process Complete	NA
Outage Management	87	Revisions due to Standard Capacity Product	5.1 and addition of section 7.3.1 to 7.3	B	9/4/2009	California ISO	Normal	Process Complete	NA
Market Operations	86	Changes to Market Operation BPM arising from Standard Capacity Product	Section 6.6.3 of the BPM	A	9/4/2009	California ISO	Normal	Process Complete	NA

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Settlements and Billing	85	New BPM Configuration guide for CC 692 Start-Up Cost Payment	Charge Code CC 692 Start-Up Cost Payment	B	9/2/2009	California ISO	Emergency	Process Complete	NA
Settlements and Billing	84	Update BPM Configuration guide for CC 7879 to define new language for Exceptional Dispatch ICPM and to replace the currently specified PTB allocation with a newly defined monthly calculation performed within the CC 7879 configuration	Charge Code CC 7879 Monthly Significant Event ICPM Allocation	B	9/2/2009	California ISO	Emergency	Process Complete	NA
Settlements and Billing	83	Update BPM Configuration guide for Measured Demand over Control Area pre-calculation to include Metered Demand output variables for use with the CC7879 Monthly Significant Event ICPM Allocation configuration.	Pre-calculation Measured Demand over Control Area	B	8/26/2009	California ISO	Emergency	Process Complete	NA
Reliability Requirements	81	Update Reliability Requirements BPM Exhibit A-2 with due dates for 2010 submittals	Exhibit A-2	A	8/19/2009	California ISO	Emergency	Process Complete	NA
Settlements and Billing	80	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	Process Complete	NA
Metering	79	Metering BPM update to reflect Payment Acceleration implementation	1.2 to 10.8 (see breakdown in Additional Qualitative Information)	A	8/7/2009	California ISO	Normal	Process Complete	NA
Market Operations	78	New Expected Energy Calculation schedule effective with Payment Acceleration	Appendix C Section C.6	A	8/7/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	77	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	California ISO	Normal	Process Complete	NA

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Transmission Planning Process	76	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	California ISO	Normal	Process Complete	NA
Credit Management	75	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	California ISO	Normal	Process Complete	NA
Rules of Conduct	74	Revisions for Payment Acceleration	various	A	8/7/2009	California ISO	Normal	Process Complete	NA
Managing Full Network Model	73	Communicate FNM updates to WECC	5.1.2 FNM Data Gathering	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	72	Definition of Maintenance Projects	3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	71	Non-approval notification process for projects other than Large Projects	New section titled: 4.3.3 Rejection Process	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	70	Large Project non-approval notification process	4.3.2 Large Project Evaluations	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	69	Non-substantive modification of Large Project description	4.3.1 Timeframe for Project Approvals	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	68	Circumstance under which projects will be recommended for ISO Board of Governors approval	4.3.1 Timeframe for Project Approvals	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	67	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	66	Modifications to the Secondary Validation Response Period.	3.2 Request Window Submission Process	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	65	Modifications to language describing Economic Planning Studies	3.1 Scope of Proposals and Projects in Request Window	A	8/5/2009	California ISO	Normal	Process Complete	NA

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Transmission Planning Process	64	Adds section heading for existing BPM language	New section titled: 2.2.3 Compliance with NERC Reliability Standards	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	63	Amending the Transmission Plan	A. New section: 2.2.2 & B. 4.3.4	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	62	Section 2.2.1 clarification and reorganization	New section titled: 2.2.1 Contents of the Transmission Plan	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	61	Language modification to clarify Transmission Plan designation.	2.2 ISO Transmission Plan	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	60	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	59	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	58	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	57	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	56	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	55	Categories of Request Window Submissions	2.1.2.1 Request Window	A	8/5/2009	California ISO	Normal	Process Complete	NA

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Transmission Planning Process	54	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	53	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	52	General Description of Request Window Categories	2.1.2.1 Request Window	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	51	The NERC Reliability criteria violation recommended solution	A. 2.1.1.2 B. 4.2	A	8/5/2009	California ISO	Normal	Process Complete	NA
Transmission Planning Process	50	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	California ISO	Normal	Process Complete	NA
Transmission Planning Process	49	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	48	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	47	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	California ISO	Emergency	Process Complete	NA
Managing Full Network Model	46	FNM Update Process Flow Digaram - Update	5.1 - Exhibit 5.1	A	8/5/2009	California ISO	Normal	Process Complete	NA

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Settlements and Billing	45	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	44	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	Process Complete	NA
Settlements and Billing	43	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	42	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	41	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	California ISO	Emergency	Process Complete	NA
Market Operations	39	New Expected Energy Types	Appendix C Section C.4.1	B	7/8/2009	California ISO	Urgent	Process Complete	NA
Market Instruments	38	Master File Update (User Interface)	Appendix B Master File Update Procedures	B	7/8/2009	California ISO	Normal	Process Complete	NA
Settlements and Billing	37	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	California ISO	Emergency	Process Complete	NA

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Settlements and Billing	36	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	35	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	34	New BPM Configuration Guide for CC 7989 effective with Payment Acceleration	BPM Configuation Guide for Charge Code 7989 Invoice Deviation Interest Distribution	C	6/24/2009	California ISO	Normal	Process Complete	NA
Compliance Monitoring	33	Dispatchable RUC Capacity	Section 7.2 Rescission of Payments for Undispatchable RUC Capacity for Generating Units, & Dynamic System Resources	B	6/24/2009	California ISO	Emergency	Process Complete	NA
Market Operations	32	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	Process Complete	NA
Market Operations	31	Clarification on transmission interface constraints modeling in market software	BPM Sections Requiring 3.2.4	A	6/17/2009	Southern California Edison	Normal	Process Complete	NA
Settlements and Billing	30	Update the BPM Configuration Guide for CC 4503 to reflect attribute changes for BASettlementIntervalBalancedTORExportEnergyQuantity	CG CC 4503 GMC CRS Export	B	6/11/2009	California ISO	Emergency	Process Complete	NA
Settlements and Billing	29	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	California ISO	Emergency	Process Complete	NA

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Settlements and Billing	28	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	27	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	California ISO	Emergency	Process Complete	NA
Settlements and Billi	26	Update BPM Configuration guide for Measu	Pre-calculation Measur	B	6/11/2009	California ISC	Emergency	Process Complete	NA
Settlements and Billing	25	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	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.	IFM Net Amount Pre-calculation	B	6/10/2009	California ISO	Emergency	Process Complete	NA
Settlements and Billing	23	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	22	Formula Change to CC 6700 Section 3.6.1.2	CC 6700 -CRR Hourly Settlement	B	6/3/2009	Pacific Gas & Electric	Urgent	Process Complete	NA
Settlements and Billing	21	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	20	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	California ISO	Normal	Process Complete	NA
Settlements and Billing	19	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	California ISO	Emergency	Process Complete	NA
Settlements and Billing	18	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	California ISO	Emergency	Process Complete	NA

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Congestion Revenue Rights	17	Global Derating Factor for CRRs	10.3.3	A	5/20/2009	Southern California Edison	Normal	Process Complete	NA
Settlements and Billing	16	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	California ISO	Emergency	Process Complete	NA
Rules of Conduct	15	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	California ISO	Normal	Process Complete	NA
Market Operations	14	Detailing Treatment of Start-Up Costs in Day-Ahead IFM Optimization	6.6	A	4/29/2009	Dynegy	Normal	Process Complete	NA

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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 1st day of February, 2010.

/s/ Anna Pascuzzo

Anna Pascuzzo