California Independent
System Operator Corporation

April 30, 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 its final quarterly report concerning the implementation of its new market design. This filing includes a Post-Implementation Report prepared by the ISO's Department of Market Services analyzing the performance of the ISO's new market[2] during the first quarter of 2010 (from January 1, 2010 through March 31, 2010) ("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- 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 directions on quarterly reporting issued in the September 2006 Order, subsequent Commission orders as noted, and ISO requirements and commitments to include issues in the quarterly reports. Since the ISO has celebrated

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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").

its first anniversary of the launch of its new markets, this is the ISO's fourth and final post-implementation quarterly report.[4]

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 January 1 through March 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.

[4] As discussed below in Section III, the MSC was not able to finish its report on alternatives to the three pivotal supplier test. The ISO has filed a separate motion for extension of time on behalf of the MSC.

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

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

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

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5 *Id.*

6 *See id.*

7 *Id.*

8 *Id.*

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

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

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

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

The Commission, in its February 19, 2009 order in Docket No. ER09-240-000, found the ISO's proposed rules and software parameters under which the ISO will relax transmission constraints, procure ancillary services, or adjust the schedules of priority self-scheduling entities when economically or operationally sensible to be just and reasonable and noted with approval the ISO's commitment to "continually evaluate the parameters in the future, both before and after the MRTU 'go-live' date."[14] The section of the market services quarterly report providing an evaluation of uneconomic adjustment parameters of 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.[15]

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

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[11] *California Independent System Operator Corp.*, 126 FERC ¶ 61,081, at PP 4, 30, 41, 58 (2009).
[12] *California Independent System Operator Corp.*, 126 FERC ¶ 61,082, at P 39 (2009).
[13] ISO Compliance Filing, Docket No. ER09-241-000 (Mar. 2, 2009), Transmittal Letter at 5 n.6.
[14] *California Independent System Operator Corp.*, 126 FERC ¶ 61,147, at P 82 (2009).
[15] The ISO will continue to file a quarterly report with FERC on transfers of Existing Contract import capability as required by tariff section 40.4.6.2.2.2.

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.

II. Market Monitoring Issues

A. 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."[16]

In the first quarterly report submitted by the ISO's Department of Market Monitoring (DMM) following implementation of the ISO's new market in April 2009, analysis by DMM indicates that use of bid-in rather than forecast demand in the pre-IFM MPM procedures could be expected to have a negligible impact on the level of mitigation in the IFM, and on final IFM schedules and prices.[17]

The level of load scheduled in the IFM has 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.

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. The ISO has indicated that in 2010 it will begin a stakeholder initiative to determine how to modify pre-IFM MPM procedures so they are based on bid-in demand by the 2012 deadline set by the Commission for this design modification.

B. 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

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16 *California Independent System Operator Corp.*, 119 FERC ¶ 61,076, at P 496 (2007).

17 Quarterly Report on Market Issues and Performance, July 30, 2009, pp 40-43 http://www.caiso.com/23fb/23fbed164b6b0.pdf.

compensation from [Resource Adequacy] requirements," and "report its findings to the Commission in its quarterly reports."[18]

As discussed in DMM's *2009 Annual report on Market Issues and Performance*, the overall frequency with which units not under Resource Adequacy or Reliability Must Run contracts have been dispatched to meet local reliability requirements and subject to mitigation under the ISO's MPM procedures has been extremely limited during 2009.[19] During the first nine months of the ISO' s new market design, none of these unit were subject to mitigation more than 20 percent of hours. Three non-resource adequacy units, representing about 1,300 MW, were subject to mitigation between 10 to 20 percent of their run hours. The remaining 3,300 MW of non-resource adequacy capacity was subject to mitigation less than 8 percent of hours.

After the first 12 months of the ISO's new market design, starting in April 2010, no units were eligible for the bid adder for frequently mitigated units, since all of this capacity was subject to mitigation well below the 80 percent threshold used to determine eligibility for this adder.

In addition, as discussed in the DMM 2009 Annual Report, a minimal amount of capacity (315 MW for a period of one month) was procured under the Interim Capacity Procurement Mechanism of the ISO tariff.[20] All units from which capacity was procured under this provision were designated as resource adequacy units for the bulk of their capacity during other months. Thus, capacity procured pursuant to resource adequacy requirements were sufficient to meet virtually all of the local area requirements, with a minimal amount of additional capacity procured under the Interim Capacity Procurement Mechanism from units with most of their capacity under resource adequacy contracts.

Based on these findings, the ISO does not propose to modify the provisions relating to frequently mitigated units in the ISO tariff at this time.

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 Market Surveillance Committee ("MSC"), during that first year, to "examine whether an alternative competitive screen to identify market power opportunities for generation in load pockets should be considered" and report on its findings.[21] The ISO anticipated that the MSC would be reporting on the Commission's directive to examine alternative approaches to the pivotal supplier test in the context of this quarterly report. Concurrently with the filing of this report, the ISO is filing a motion on behalf of the MSC for a four week

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18 *California Independent System Operator Corp.*, 119 FERC ¶ 61,313, at P 352 (2007).

19 *2009 Annual Report on Market Issues and Performance*, California Independent System Operator, Department of Market Monitoring, April 2010, pp.4.20 - 4.23, (see Figures 4.15 and 4.16) http://www.caiso.com/2777/27778a322d0f0.pdf.

20 *Id.* at pp. 7.13 – 7.14.

21 September 2006 Order at P 1032.

extension of time. The four week period will also allow the MSC to publish a draft report, obtain comments and to finalize and adopt the report through its public process.

As noted in prior quarterly reports, the ISO's DMM has performed a variety of analyses of the performance of the local market power mitigation provisions of the ISO's new market design, and has presented these for discussion at three prior MSC meetings. Results of these analyses are also presented in DMM's 2009 Annual Report.[22] As noted in DMM's Annual Report, DMM believes this analysis indicates that the current competitiveness screen and other local market power mitigation provisions are working well to effectively mitigate local market power with a relatively limited frequency of mitigation of market bid prices. DMM is currently developing tools that would allow the competiveness screen to be updated more quickly based on actual system conditions. Once these tools are in place, DMM will initiate a process to consider changes in current procedures to make the competiveness screen more dynamic and reflective of actual system and market conditions.[23]

IV. Contents of Filing and Service

In addition to this transmittal letter, this filing includes Attachment A, the market services quarterly report. In addition to serving this filing on all parties on the official service lists, the ISO 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,

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[22] *Id.* at 4.1 – 4.36.
[23] *Id.* at 4.29 – 4.36.

Attachment A
Market Services Quarterly Report

California Independent
System Operator Corporation

California ISO

Post Implementation Report

April, 2010

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Introduction

This report is prepared under the direction of Market Services, which is part of the Operations division of the California Independent System Operator Corporation (ISO). Contemporaneously with this report, the ISO's Department of Market Monitoring (DMM) 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 "submit quarterly reports evaluating MRTU performance and operational issues for the first year . . .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 to be included in the quarterly reports, which are referenced via footnotes at the start of each section in this report. This report covers the January 1 through March 31, 2010 time period and is, therefore, the final post implementation quarterly report.

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

Market Performance[2]

Market Characteristics

Loads

Generally loads declined when the weather became warmer during the period from January 1 to March 31 in 2010. Loads were below 32,000 MW during the reporting period, and lower than last year for most days during the reporting period most likely due to milder weather. The stormy and colder weather around January 20 and colder than normal temperatures in the week ended March 12 drove loads higher than the corresponding period a year ago.

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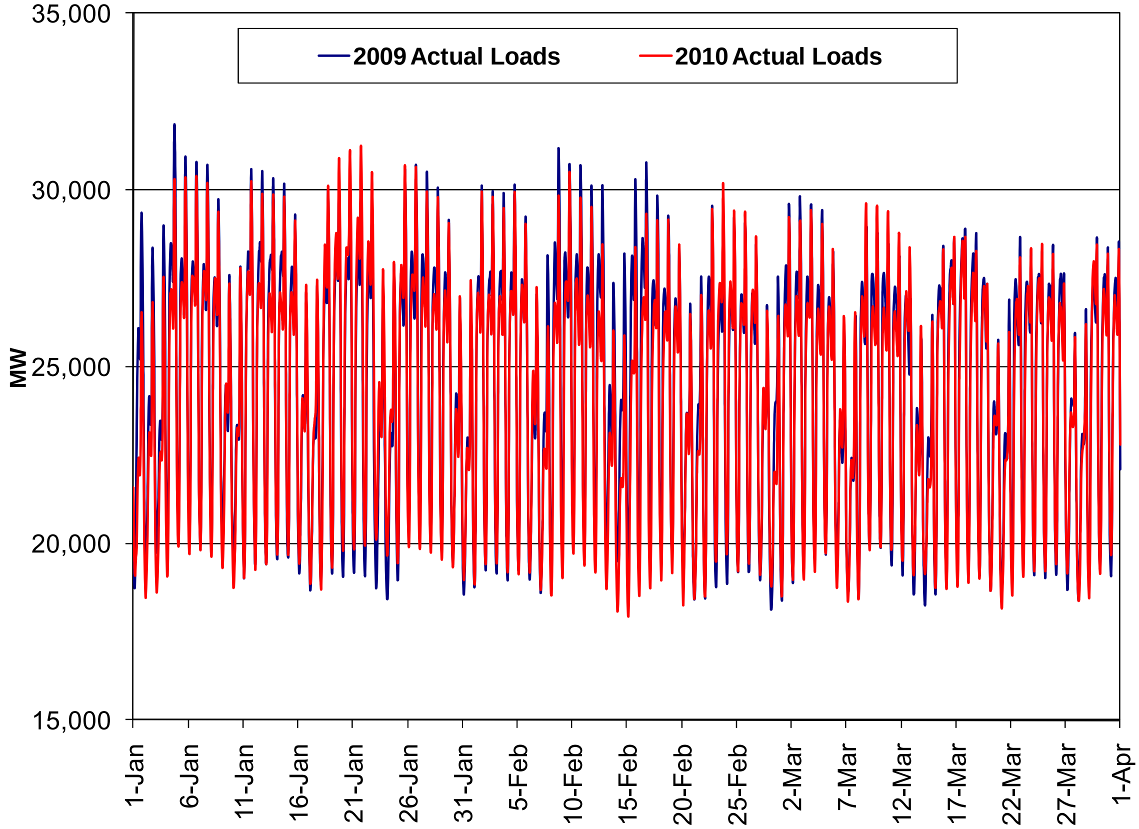
[2] This section of the report is based on paragraph 1417 of the September 21, 2006 FERC Order, in which FERC directed the ISO to file reports and provide an opportunity for market participants to contribute to the nature of the reports. Consistent with this requirement, the ISO held a series of stakeholder 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 first quarter of 2010, 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 Market Disruptions and on the 15th and 30th of every month, the ISO files reports addressing Exceptional Dispatch. (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. Metrics on uplift payments as well as many other market metrics are now included in the Monthly Market Performance report and metric catalogue available at http://www.caiso.com/205c/205cb4c74bc40.html.

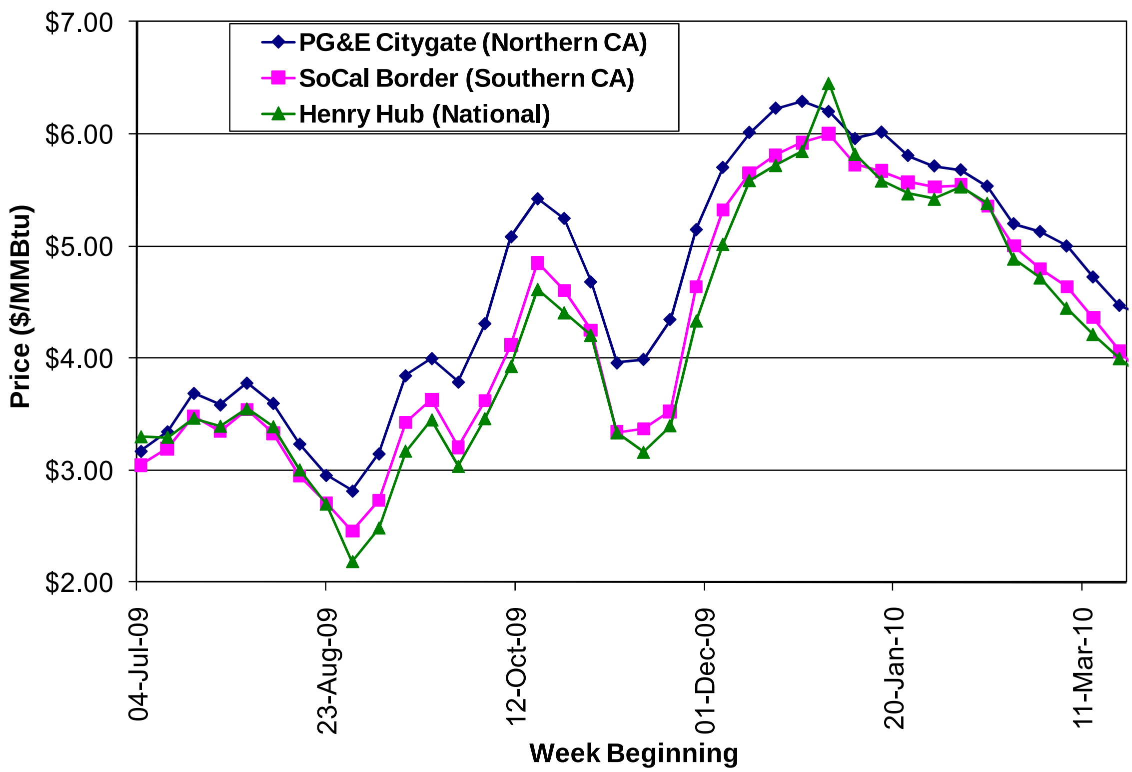
Figure 1: System Load Comparison –2010 vs. 2009



Natural Gas Prices and Inventories

Figure 2 shows a downward trend in natural gas prices from January 1 through March 31 in 2010. The main contributors to the declining prices include warmer weather, ample domestic production, especially from the unconventional gas fields in Appalachia and Louisiana, and an increase in natural gas imports. At the beginning of January, frigid weather across most states of the U.S. and rising crude oil prices drove up the natural gas prices. However, the natural gas prices in California did not move much as the weather was less severe. Indeed, the prices in the Northern California declined a bit. Therefore, Figure 2 shows a price peak for Henry Hub at the beginning of January. The California Composite Average gas price fell approximately 31 percent to $4.18 per MMBtu on March 31 from $6.06 per MMBtu on January 4.

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



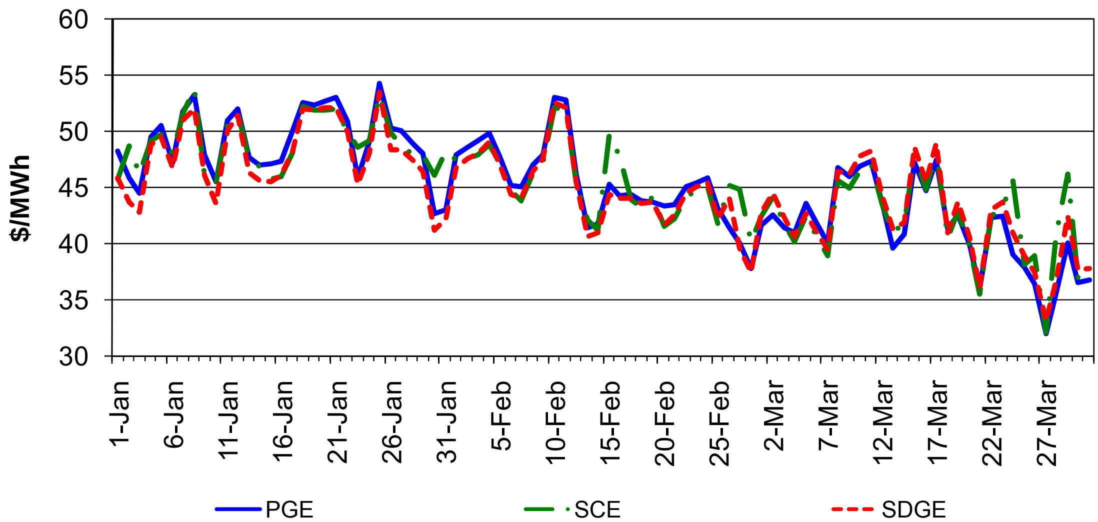
Market Performance Metrics

Energy

Day-Ahead Prices

Figure 3 shows the daily day-ahead load aggregation point (LAP) prices for the first quarter of 2010. The daily average day-ahead default LAP prices were fairly stable for the quarter, falling into the range of $32/MWh to $54/MWh. Prices in the SCE LAP diverged from the prices in the other two LAPs for the quarter on several days, mostly driven by the congestion on the SCE_PCT_IMP branch group with exceptions on two days. On February 26, the congestion on the SLIC_1108011_VINCNT nomogram elevated energy prices in the SCE and SDG&E LAPs. This nomogram was created to account for the scheduled outage of a transmission facility. On March 2, Path 26 was congested due to a derate driven by the scheduled outage of Midway-Vincent #3 500 kV line. This congestion elevated the energy prices in the SCE and SDG&E areas. Consistent with the movement of the natural gas prices, the day-ahead market (DAM) saw a declining trend in energy prices during the second half of the quarter.

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 first quarter of 2010. Price divergence among three default LAPs was observed on several days for the quarter, mainly due to the congestion on the SCE_PCT_IMP branch group with exceptions on six days. On February 25 and 26, the congestion on the SLIC_1108011_VINCNT nomogram elevated energy prices in the SCE and SDG&E areas. As mentioned previously, this nomogram was created to account for the scheduled outage of a transmission facility. The congestion, combined with over generation, contributed to low negative prices in the PG&E area on February 26. On March 2, Path 26 was also congested in the real-time market due to the derate mentioned in the previous section. On March 20, this branch group was binding again due to a derate driven by the annual functional output tests of the WECC remedial action scheme and the internal remedial action scheme in PG&E. The congestion on both days elevated the energy price in the SCE and SDG&E areas. On March 24, the SDGE_CFE import branch group was derated to accommodate the scheduled outage of Otay Mesa-Tijuana 230 kV line; this line returned later than it was scheduled. The late return of this line resulted in the congestion on the SDGE_CFE import branch group, elevating the energy prices in the SDG&E area. On March 25, the SDGEIMP branch group was binding due to derate motivated by the scheduled outage of Otay Mesa-Tijuana 230 kV line; this branch group was dynamically adjusted to preserve the reliability margin throughout the day. The congestion resulted in higher prices in the SDG&E LAP. The real-time energy prices were generally moderate for the quarter, the daily average real-time energy prices for three default LAPs were between $29/MWh and $125/MWh.

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

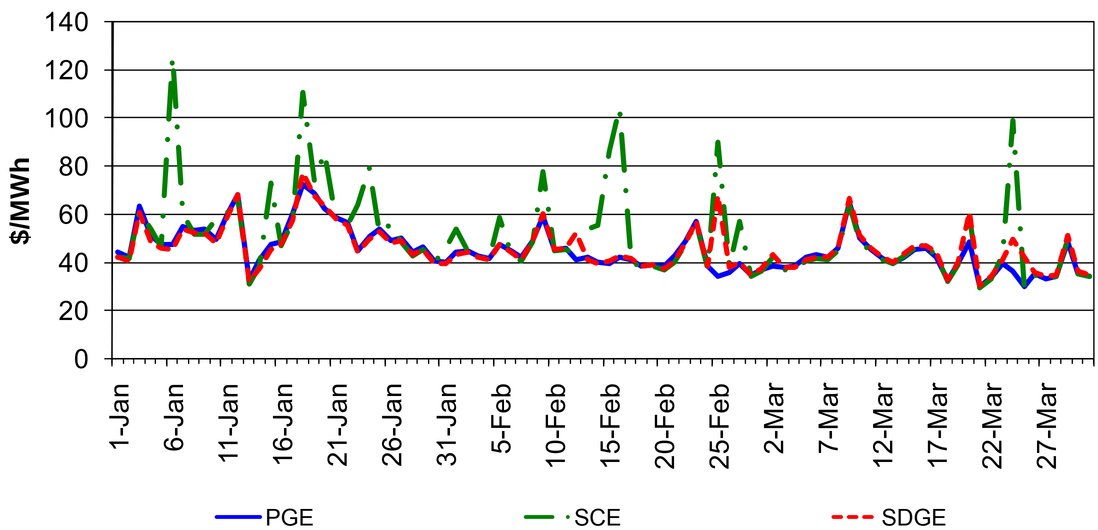


Figure 5 shows the daily frequency of price spikes by price range for the three default LAPs in the five-minute real-time dispatch (RTD) during the first quarter of 2010. In percentage terms, the frequencies of prices over $250/MWh declined from 0.9 percent in January to 0.5 percent in February and ended at 0.3 percent in March. Similarly, extreme prices (over $1000/MWh) declined from 0.03 in January to 0.02 in February and ended at 0.01 in March. Reasons for high prices have been explained in previous sections.

Figure 5: Daily Frequency of RTD LAP Positive Price Spikes

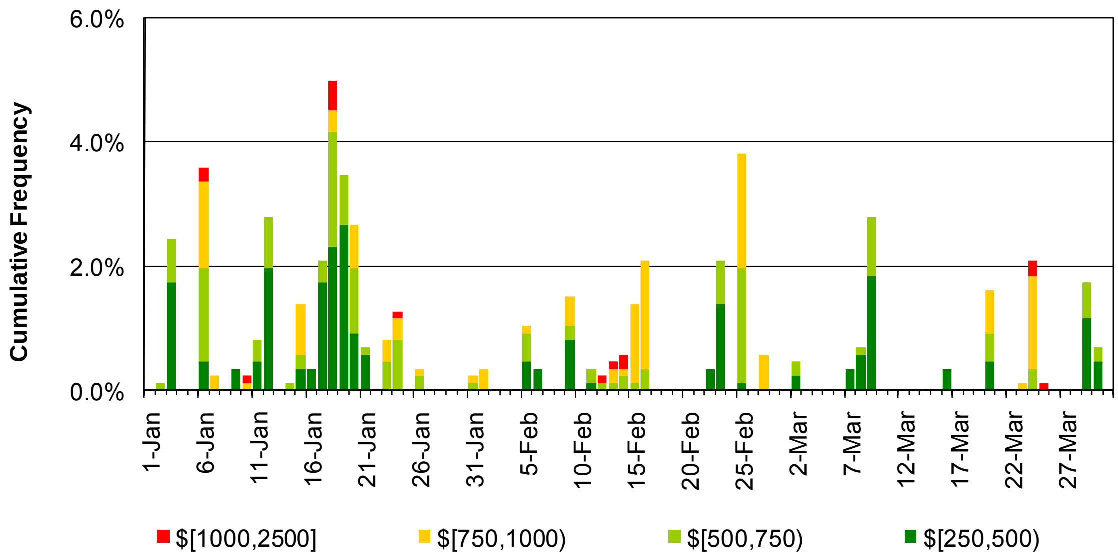
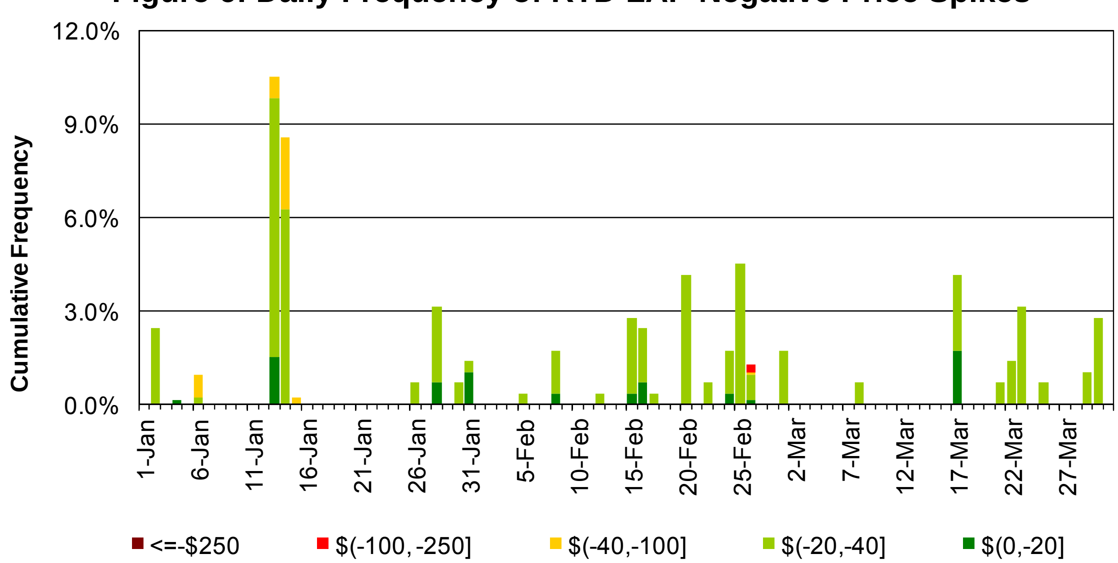


Figure 6 shows the daily frequency of negative prices by price range for all three default LAPs in the five-minute real-time market. The frequency of negative prices declined to 0.5 percent in March from 0.7 percent of February and 0.9 of January.

Figure 6: Daily Frequency of RTD LAP Negative Price Spikes

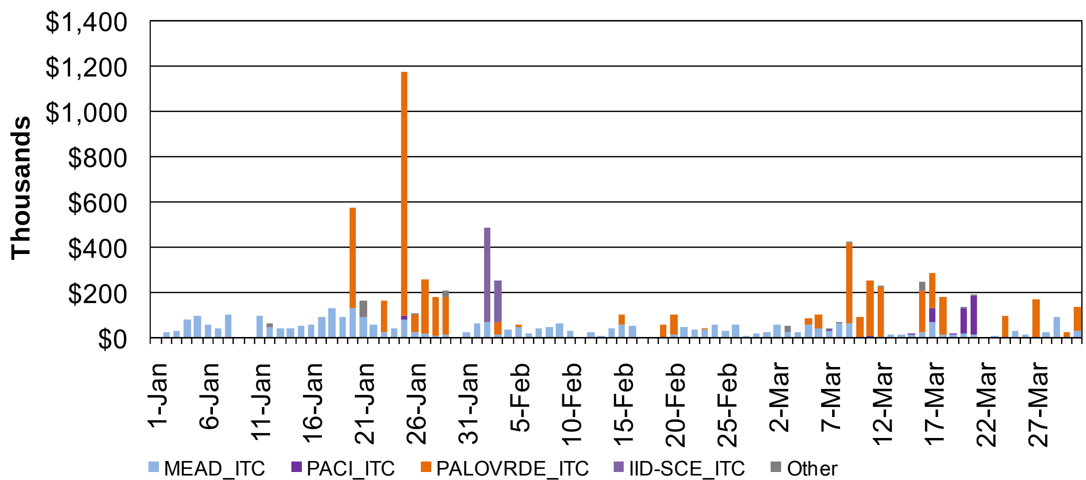


Congestion

Congestion Rents on Interties

Figure 7 below illustrates the daily total integrated forward market (IFM) congestion rents by interties for the first quarter of 2010, 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 interties. The cumulative congestion rent on interties for the first quarter of 2010 was $9 million, much lower than the $30 million in the fourth quarter of 2009. 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 two interties: Palo Verde (49 percent) and Mead (38 percent).

Figure 7: IFM Congestion Rents by Interties (Import)



The congestion rents on Palo Verde intertie occurred mainly in January and March 2010. In January the average shadow price on the Palo Verde intertie was $9.95/MWh and, the total congestion rent was $2.3 million. Almost 50 percent of the $2.3 million congestion rent occurred on January 25, when the Palo Verde intertie was derated by 1,000 MW due to the outages of Captain Jack-Olinda and Olinda-Tracy 500 kV lines. In March, total congestion rent on the Palo Verde intertie was $1.89 million; of this total, more than 50 percent of congestion rents occurred between March 9 and March 12, driven by path capacity derates due to the planned outage of the Hassayampa-North Gila 500 kV line.

Total congestion rent on Mead intertie during the first quarter of 2010 was $3.44 million. This was spread evenly among the three months in the first quarter. Almost all congestion rents were due to over scheduling on the Mead intertie by various scheduling coordinators.

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

Intertie	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
ADLANTO-SP_ITC	Jan-2010	1,147	3.72	16
ELDORADO_ITC	Jan-2010	1,157	3.98	6
MEAD_ITC	Jan-2010	821	7.02	291
NOB_ITC	Jan-2010	0	21.38	1
PACI_ITC	Jan-2010	2,318	4.06	2
PALOVRDE_ITC	Jan-2010	2,235	9.95	108
PARKER_ITC	Jan-2010	135	15.49	15
SILVERPK_ITC	Jan-2010	0	20.53	125
IID-SCE_ITC	Feb-2010	586	21.82	47
MEAD_ITC	Feb-2010	814	4.02	296
PALOVRDE_ITC	Feb-2010	2,782	2.59	37
SILVERPK_ITC	Feb-2010	0	13.29	97
ADLANTO-SP_ITC	Mar-2010	1,144	2.07	12
BLYTHE_ITC	Mar-2010	25	21.68	24
CASCADE_ITC	Mar-2010	25	4.33	6
COTPISO_ITC	Mar-2010	10	0.95	2
MEAD_ITC	Mar-2010	800	4.26	246
NOB_ITC	Mar-2010	966	3.76	5
PACI_ITC	Mar-2010	1,113	7.77	58
PALOVRDE_ITC	Mar-2010	1,665	9.99	150
PARKER_ITC	Mar-2010	195	26.22	2
SILVERPK_ITC	Mar-2010	0	16.43	98

Congestion Rents on Branch Groups and Market Scheduling Limits

Figure 8 illustrates daily 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 groups and market scheduling limits for the first quarter of 2010. The daily 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 first quarter of 2010, total branch group and market scheduling limit congestion rent was $13 million, down from $19 million in the fourth quarter of 2009. The majority of branch group and market scheduling limit congestion rents occurred on Southern California Edison Percent Import (83 percent) and Intermountain DC- Adelanto (7 percent) branch group.

Figure 8: IFM Congestion Rents by Branch Group

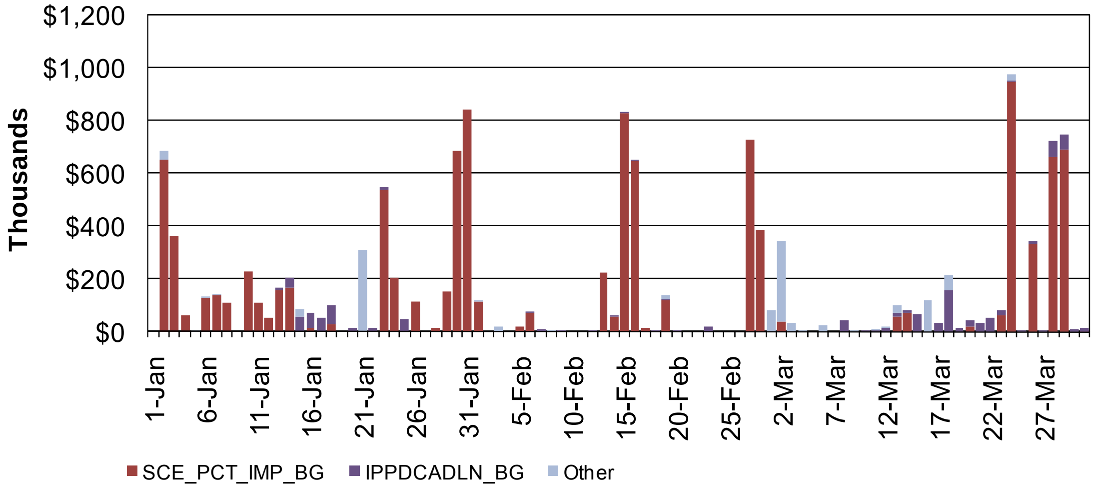


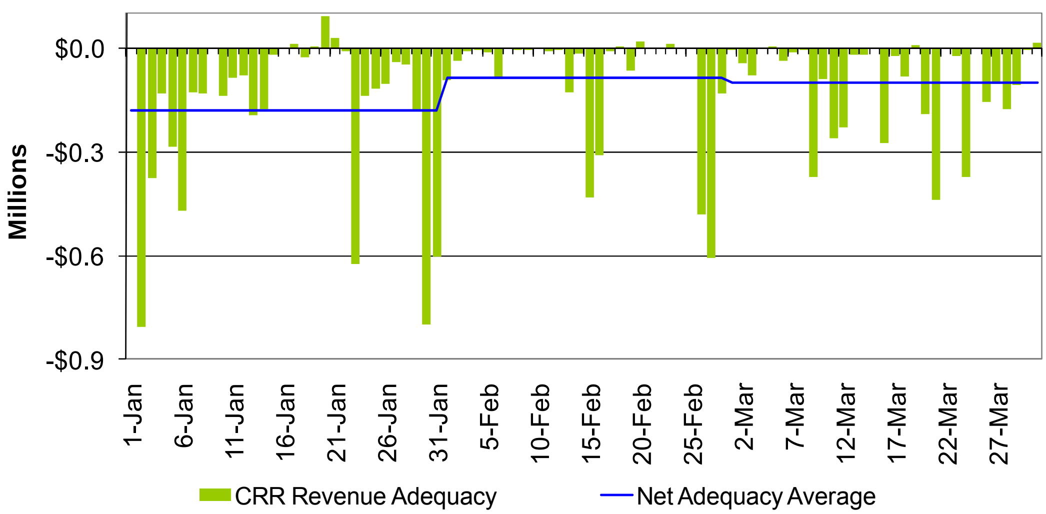
Table 2: IFM Congestion Statistics by Branch Group

Branch Group/ Market Scheduling Limit	Month	Average Cleared Value (MW)	Average Shadow Price ($/MWh)	Number of Congested Hours
HUMBOLDT_BG	Jan-2010	43	142.23	6
IPPDCADLN_BG	Jan-2010	647	3.72	152
MKTPCADLN_MSL	Jan-2010	605	33.83	15
PATH15_BG	Jan-2010	3,100	1.93	6
SCE_PCT_IMP_BG	Jan-2010	6,367	6.05	122
IPP-IPPGEN_MSL	Feb-2010	470	27.35	1
IPPDCADLN_BG	Feb-2010	556	1.91	45
MONAIPPDC_MSL	Feb-2010	162	1.04	3
SCE_PCT_IMP_BG	Feb-2010	6,438	8.72	56
SOUTHLUGO_RV_BG	Feb-2010	3,200	3.28	2
HUMBOLDT_BG	Mar-2010	43	190.68	7
IPP-IPPGEN_MSL	Mar-2010	470	19.60	28
IPPDCADLN_BG	Mar-2010	633	3.95	264
MKTPCADLN_MSL	Mar-2010	404	16.09	21
PATH26_BG	Mar-2010	2,030	4.62	20
SCE_PCT_IMP_BG	Mar-2010	6,944	8.31	50
SDGEIMP_BG	Mar-2010	1,750	3.42	4
WSTWGMEAD_MSL	Mar-2010	165	1.74	7

Congestion Revenue Rights[3]

Figure 9 illustrates the revenue adequacy for congestion revenue rights (CRRs) for the first quarter of 2010. 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, once the exemptions for existing transmission rights are deducted. A net positive value indicates that there is a surplus and a net negative value indicates there is a shortfall.[4]

Figure 9: Daily Revenue Adequacy of Congestion Revenue Rights



The net daily revenue adequacy is provided in the green bars in Figure 9. In addition, a daily average is estimated for each month and is shown as a blue line. The net CRR revenue adequacy 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

[3] 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.

[4] Congestion rents available from the integrated forward market do not include congestion revenue from holders of existing rights (transmission ownership rights (TOR), existing transmission contracts (ETC) and Converted Rights (CVR)), because users of the ISO grid under such rights are exempt from congestion charges. This requirement is based on grandfathered transmission contracts and is written into the ISO tariff. The ISO respects this requirement and enforces it by immediately reversing and not charging any and all congestion charges that are levied on these rights holders. Consequently, 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 under such rights to factor into the CRR release process the need to honor such rights. The ISO's modeling of such rights for the purpose of releasing CRRs, does not, however, affect in any way the ISO's application of the reversal of congestion charges to holders of such rights in actual market operations.

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. As shown in Figure 9, the first quarter of 2010 saw a consistent shortfall. The daily average of revenue deficiency was $179,023 in January, $85,331 in February and $98,992 in March, respectively.

There were 24, 19 and 24 days in which revenue deficiencies were observed in January, February and March, respectively. The main factors driving revenue shortfalls in the first quarter of 2010 include:

January, 2010

Throughout January the SCE_PCT_IMP branch group was binding frequently, driving revenue deficiencies in 21 days of the month and producing 78 percent of the monthly revenue deficiencies. This constraint started to be enforced in the energy market on November 11, 2009. With a forward-looking timeframe for releasing congestion revenue rights, however, the same constraint was not enforced in the annual and monthly CRR release processes. Other elements impacting revenue inadequacy were:

- La Fresa-Hinson line was binding from January 3 through January 6 and accrued deficiencies because it was impacted by the outages of two transmission lines. These outages changed the transmission configuration and thus the shift factors of the La Fresa-Hinson line, creating a mismatch between the transmission capacities released through CRRs versus the capacity used in the energy market. Afterwards, the nomogram ELNIDO-LAFRESA was created to account for these same outages and for the rest of the month this nomogram was frequently congested, driving revenue deficiencies as well.

- With the forced outage of the Captain-Jack Olinda line, the Palo Verde intertie was derated to 2,480 MW from January 23 through January 26, resulting in a shortfall of $168,000. This cumulative deficiency partially offset the revenue surplus of $80,000 collected on Palo Verde on January 20. The same transmission line outage also led to derates on the PACI intertie on January 25.

February, 2010

The main driver of revenue deficiencies in February was the SCE_PCT_IMP branch group, with 11 days of deficiencies. This constraint was enforced in the energy market but it was not enforced in the various CRR processes. This resulted in releasing too much transmission capacity on this constraint in the

CRR processes in comparison to the limited capacity released in the energy market. Starting with the month of February, the monthly processes to release CRRs started to account for the SCE_PCT_IMP branch group. However, 75 percent of the transmission capacity was already released in the annual process in which this branch group constraint was not enforced. Therefore, the enforcement of this branch group constraint in the monthly processes simply stopped the further release of CRRs on this constraint but could not avoid the deficiencies accrued on the CRRs already released in the annual process and, revenue deficiencies due to congestion on this constraint did still occur. Other factors impacting revenue inadequacy include:

- On February 26 congestion on the SLIC_1108011_VINCNT nomogram contributed to 19 percent of CRR revenue deficiency. This nomogram was temporarily created to account for the planned outage of a transmission facility, which implicitly put a tighter limit on the transmission capacity released in the energy market.

- Deficiencies accrued on the SILVER_PEAK intertie throughout the month when it was derated to 0 MW in the import direction to account for internal work on its station.

- The ELNIDO-LAFRESA nomogram also produced revenue deficiencies through the first half of the month. Similar to previous months, this nomogram was in place to account for outages of two different transmission lines.

March 2010

The Palo Verde intertie was derated to 1,461 MW between March 9 and March 12 due to the planned outage of the North Gila-Hassayampa 500kV line. Then it was derated to 1,034 MW on March 16 to reflect the planned outage of the Palo Verde-Devers 500kV line. On March 27 the North Gila- Imperial Valley 500 kV line was out of service and required Palo Verde to be derated to 1,791 MW. Other contributors to revenue shortfalls include:

- Deficiencies accrued on SCE_PCT_IMP branch group when it experienced congestion, mostly in the latter half of the month.

- The PACI intertie also accrued deficiencies on March 20 and 21 when it was derated to 1,400 MW due to the planned annual functional output tests of the WECC remedial action scheme (RAS) and the internal RAS (IRAS).

- On March 18, the Humboldt branch group experienced congestion and the energy flows were lower than the CRR flows, this gap was priced at $500 prices.

- On March 3, the BLYTHE intertie was derated to 25 MW due to the forced outage of the Eagle Mountain-Blythe 161kV line and this resulted in revenue shortfalls.

- Path 26 was derated to 2,000 MW during the first five days of March to reflect the planned outage of the Midway-Vincent #3 500kV line, creating revenue shortfalls.

Table 3 provides a summary of the monthly statistics for CRRs for the first quarter of 2010. The net revenue adequacy accounts for both the CRR adequacy and the cost of the existing rights exemption. The revenue adequacy ratio is the ratio of the available congestion rents to the CRR payments. 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 January and March. 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: Monthly Summary of Revenue Adequacy

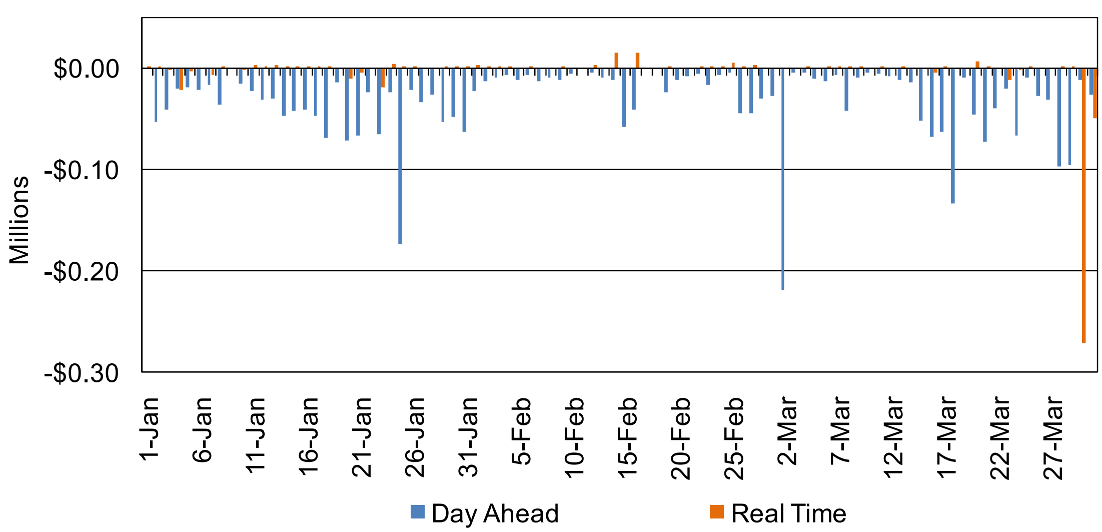
	JANUARY	FEBRUARY	MARCH
Congestion Rents	$11,427,346.73	$5,901,281.01	$7,533,701.65
Existing Rights Exemptions	-$1,238,756.39	-$437,536.23	-$1,252,586.11
Available Congestion Rents	$10,188,590.34	$5,463,744.79	$6,281,115.54
CRR Payments	$15,738,318.76	$7,853,030.78	$9,349,868.77
CRR Adequacy	-$5,549,728.42	-$2,389,285.99	-$3,068,753.23
Adequacy Ratio	64.74%	69.57%	67.18%
Auction Revenues	$3,638,421.1	$2,761,663.9	$2,654,787.1
Monthly Net Balance	-$1,911,307.3	$372,377.9	-$413,966.1

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 day-ahead and/or real-time, (i.e., in the hour-ahead scheduling process or real-time dispatch period) schedule changes with respect to their accepted day-ahead self-schedules.[5] As required by the ISO tariff, schedules associated with existing rights are not subject to congestion charges. This provision applies to both the day-ahead and the real-time markets, and 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 day-ahead and real-time 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 corresponding 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 corresponding congestion payment.

Figure 10: Cost of Exemptions for Existing Rights



[5] 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 depends not only on the congestion but also on the extent of schedule submitted by their holders. As shown in Figure 10, the cost of the existing rights exemption for real time was generally much lower in comparison to that of the day ahead, with the exception of two days in March.

Ancillary Service Markets

Integrated Forward Market (Day-Ahead) Average Prices

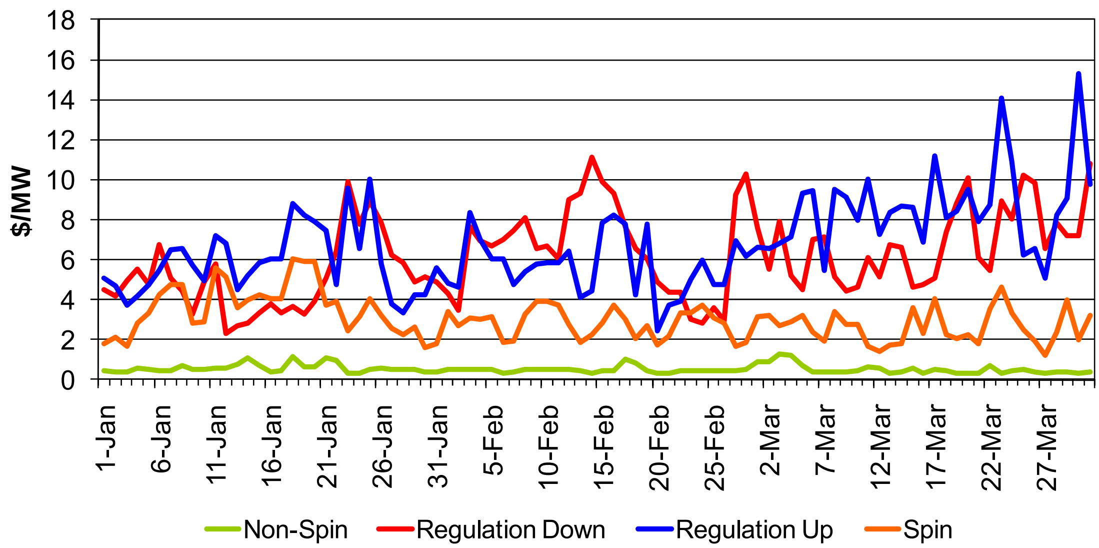
Table 4 shows the daily day-ahead average ancillary service procurements and prices for the first quarter of 2009, and Figure 11 shows the daily integrated forward market average prices. The daily average price for each type of ancillary service is calculated as the average of the hourly price for all trading hours, where the hourly price is equal to total cost of procuring non-self scheduled ancillary service divided by total non-self scheduled procurement.

The hourly average regulation up, regulation down, and non-spinning procurement quantity declined gradually from January to March, and hourly average spinning procurement was between 770 MW to 776 MW for this quarter. The hourly average price for regulation up increased in March, driven by the increasing regulation up regional shadow price in the SP 26 expanded system region. The hourly average price for regulation down gradually increased from $5.04/MW in January to $6.86/MW in March. The average prices for the first quarter for spinning and non-spinning reserves were $3.02/MW and $0.53/MW, respectively.

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

	Average Procurred				Average Price			
	Reg Up	Reg Dn	Spinning	Non-Spinning	Reg Up	Reg Dn	Spinning	Non-Spinning
JAN	376	342	776	787	$5.92	$5.04	$3.59	$0.58
FEB	371	332	770	774	$5.68	$6.62	$2.82	$0.49
MAR	362	327	773	772	$8.61	$6.86	$2.64	$0.52

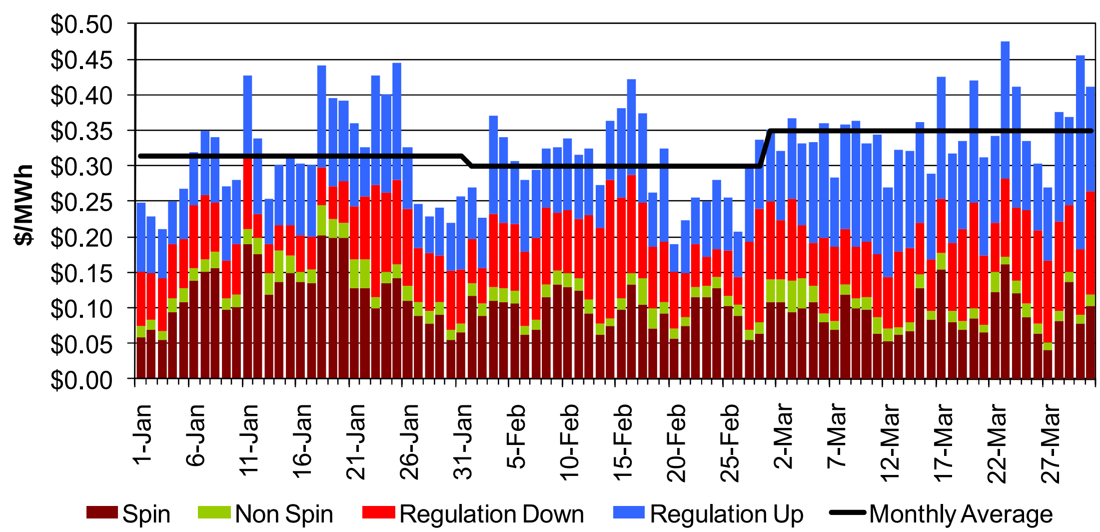
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Services Cost to Load

Figure 12 below shows total system (day-ahead and real-time) average cost to load for ancillary services procured for the first quarter of 2010. The average cost to load for each type of ancillary services is calculated as total hourly cost of procurement for that type of ancillary services divided by total hourly ISO load. The monthly average cost to load increased during the first quarter, from \$0.31/MWh in January to \$0.35/MWh in March. The increasing trend in the ancillary services cost to load in March was due to the increase in regulation up ancillary service, which was driven by increasing regulation up regional shadow price in the SP26 expanded system region, as mentioned in the previous section.

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 first quarter of 2010. Approximately 97.65 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 significantly by 45.3 percent, from 279 MW in January to 192 MW in March.

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

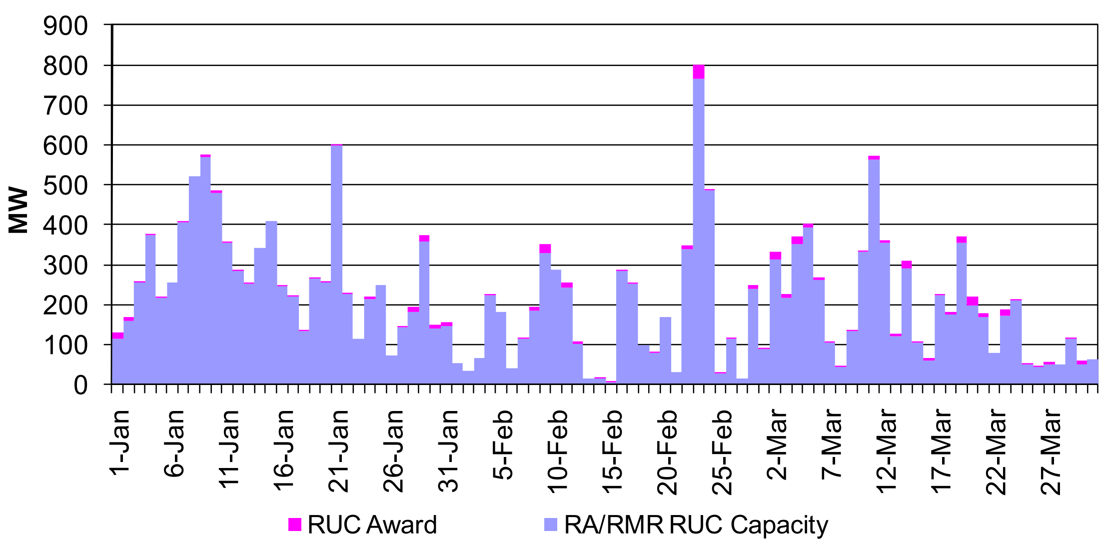
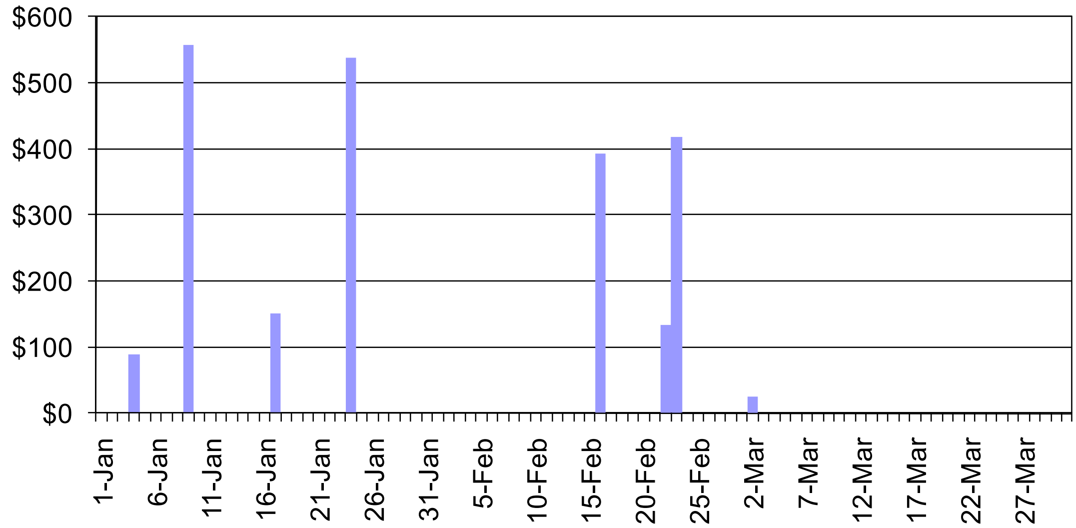


Figure 14 shows the daily cost of residual unit commitment procurement for each trading day for the first quarter of 2010. The monthly residual unit commitment procurement costs were $1,336, $943 and $25 in January, February and March, respectively.

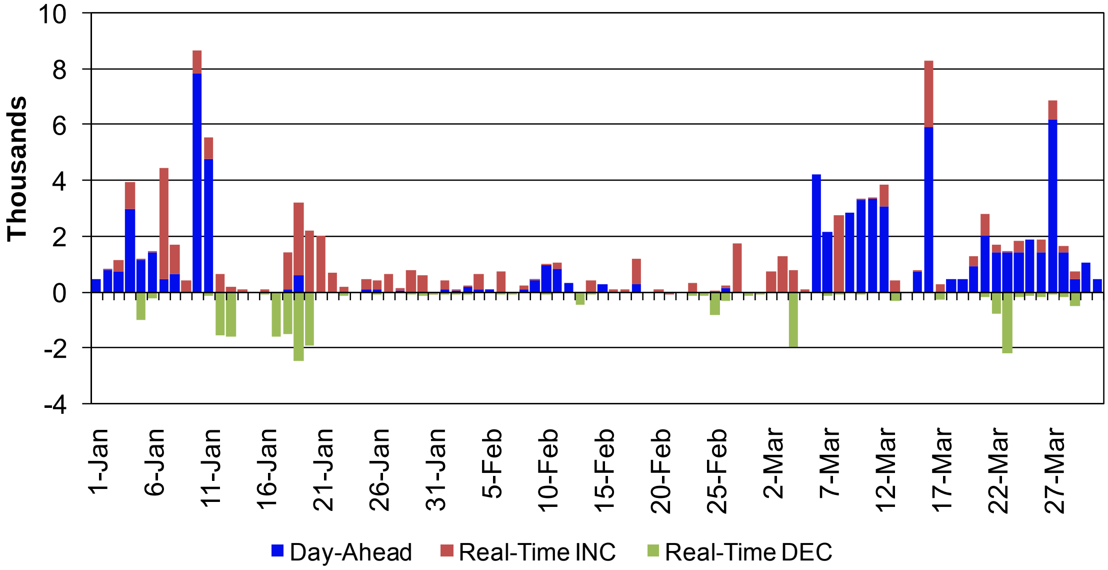
Figure 14: Total RUC Cost



Exceptional Dispatch

Figure 15 indicates the instances of exceptional dispatches broken out by type of dispatch for the reporting period January 1 through March 31.[6] Total volume of exceptional dispatch in the first quarter of 2010 was 94,019 MWh. The months of January, February and March contributed 34 percent, 9 percent and 57 percent, respectively, to the quarterly total.

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



6 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[7]

This section reflects summarized information already presented in this report. Table 5 lists the monthly summary of both the day-ahead and real-time 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 of honoring the existing rights exemption in comparison to the overall congestion cost of the day-ahead and real-time markets.

Table 5: Summary of the Cost Associated to the Existing Rights Exemption[8]

	DA Market			RT Market		
Month	Congestion Rents	Existing Rights Exemption	Cost Percentage	Congestion Rents	Existing Rights Exemption	Cost Percentage
JANUARY	$11,427,346.73	-$1,238,756.39	-10.84%	-$3,569,932.05	-$57,584.72	1.61%
FEBRUARY	$5,901,281.01	-$437,536.23	-7.41%	-$6,155,542.71	$48,354.81	0.79%
MARCH	$7,533,701.65	-$1,252,586.11	-16.63%	-$50,019.96	-$331,542.21	662.82%
Total	$24,862,329.40	-$2,928,878.72	-11.78%	-$9,775,494.72	-$340,772.12	3.49%

The cost of the existing rights exemption charge to load not under an existing right in the day-ahead market during the first quarter was $2.92 million, which represents 11.8 percent of the congestion rents collected in the integrated forward market, down from the 12.5 percent of the fourth quarter of 2009. As detailed in the congestion revenue right section above, in each month of the quarter, the existing rights exemption requirements reduced the available funds

[7] As required by FERC's Order Accepting Compliance Filing issued on September 22, 2006 (*California Indep. Sys. Operator, Corp.*, 116 FERC ¶ 61,281, (2006)), 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 meta document 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.

[8] In the month of March the existing rights exemption is significantly more negative than the real-time congestion rents. The real-time congestion rents are often negative simply because the settlement in the real-time market is on incremental change from the day-ahead market. Thus, if the real-time MW value is below the day-ahead MW value (i.e. a negative MW value) then a positive congestion price results in a negative settlement (negative MW value multiplied by positive congestion price), and the scheduling entity receives a payment. This effectively backs out the day-ahead congestion payment, but at the real-time price. Netting out the incremental MWs and decremental MWs from the day-ahead schedules generally produces a net negative value overall. The existing rights exemption is negative in the day-ahead market, and as long as the real-time schedules are generally positive increments over the day-ahead values then the real-time exemption remains negative. The fact that the existing rights exemption is negative is not directly related to the fact that the real-time congestion rents are negative. The existing rights exemption is, in essence, an offsetting charge for the calculated congestion charge. In February the existing rights exemption was positive, indicating that after netting the existing rights exemption MWs were negative. In addition to these drivers of the negative prices there are other second order effects that can also contribute to this characteristic, such as the fact that the real-time LMPs in the hour-ahead scheduling process and real-time dispatch runs may be different.

from the congestion revenues of the integrated forward market. Compared to the integrated forward market costs, the cost of the existing rights exemption in the real-time market was lower, about $0.34 million, with most of that cost collected in March. The real-time cost of the existing rights exemption amounts to a third of the percentage of the day-ahead cost, at 3.5 percent of the total congestion cost for this quarter, down from the 12.6 percent observed in the first quarter of 2010. Congestion revenues in the real-time market were a negative balance (deficit) and were allocated to non-ETC/TOR measured demand. The cost of existing right exemptions in the quarter 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.

Reliability – Compliance with NERC Reliability Standards[9]

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.

As noted in our the prior reports, the ISO is subject to this comprehensive compliance regime established under section 215 of the Federal Power Act and implemented by the Commission, NERC, and WECC. ISO has a robust program for 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 findings in the reports of both reviews were quite favorable and contained nothing to even remotely suggest that the new market design has had an impact on compliance with NERC Standards. WECC found that the ISO has a strong culture of compliance and that its compliance program fully complies with the elements of the Commission's Revised Statement Enforcement that are considered as an entities commitment to compliance.

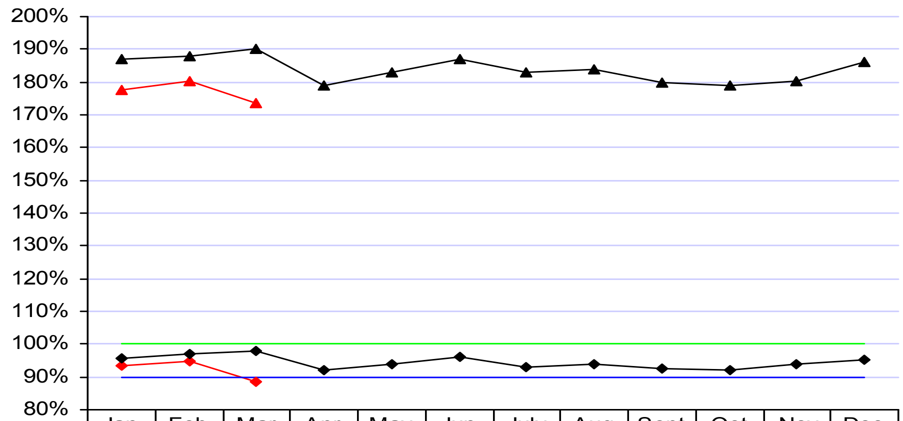
As an example of compliance with mandatory reliability standards, ISO management prepares an Operations Highlights Report for each meeting of the board of governors. This report illustrates the compliance of current ISO operations with NERC reliability standards regarding reliable grid operations. In particular, the Operations Highlights Report contains data indicating that, since 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

[9] 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.

percentage of at least 100 percent and a CPS 2 percentage of at least 90 percent are required for full compliance.

Figure 16 provides the CPS 1 and CPS 2 data for January through March 2010 as well as data for 2009 for comparison. For 2010, the data shows that the CPS 1 percentages were all above 100 percent, and the CPS 2 percentages were above 90 percent for January and February, and slightly below 90 percent for March.[10]

Figure 16: CPS1 and CPS2 Violations

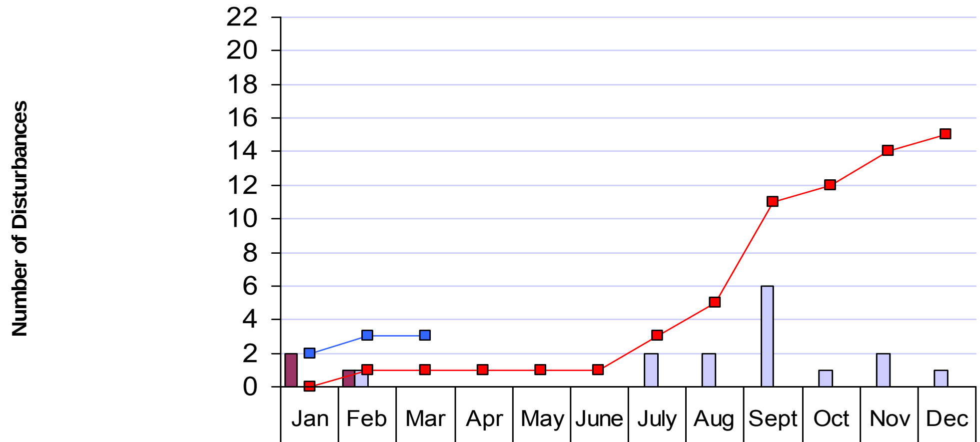


	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
'10 CPS 1	178%	180%	174%									
'10 CPS 2	93.32	94.67	88.40									
'09 CSP 1	187%	188%	190%	179%	183%	187%	183%	184%	180%	179%	180%	186%
'09 CPS 2	95.76	97.15	97.79	92.29	93.68	95.90	93.07	94.01	92.57	92.09	93.95	95.43
CPS1 Min Req	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CPS2 Min Req	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%

10 CPS2 percentage measures dropped below 90% in March. This was due to the fact that the CAISO is no longer required to maintain CPS2 standards as it began a Reliability Based Control field trial on March 1st 2010 under a Western Electricity Coordinating Council (WECC) program. Further details of this program are available at: http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2fcommittees%2fStandingCommittees%2fOC%2fOPS%2fPWG%2fShared%20Documents%2fReliability%20Based%20Control%20Field%20Trial%20Workshop%20-%20August%202009&FolderCTID=&View={D0C43BDA-B9DA-4B32-B06C-8D3A157FEE9B}

Figure 17 provides the DCS data for January through March 2010 as well as data for 2009 for comparison. For 2009, the data shows the number of DCS violations was zero.

Figure 17: 2009 and 2010 DCS Violations



	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Inside ISO '10	2	1	0									
Inside ISO '09	0	1	0	0	0	0	2	2	6	1	2	1
ISO DCS Violations '10	0	0	0									
ISO DCS Violations '09	0	0	0	0	0	0	0	0	0	0	0	0
'10 YTD Disturbances Total	2	3	3									
'09 YTD Disturbances Total	0	1	1	1	1	1	3	5	11	12	14	15

Reliability – Assessment of Ancillary Service Control[11]

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, unavailable or unconnected 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 assessment of the reporting

[11] 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."

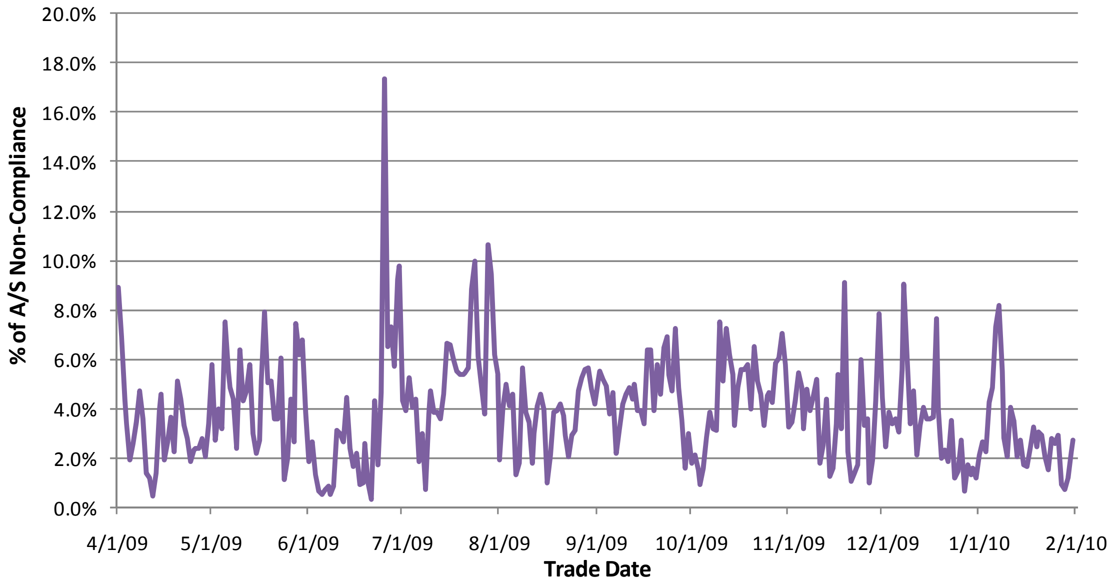
In general this section addresses item (2). Specifically the no-pay section addresses footnote items (1), (2), and (4) listed above, whilst the "ACE and Voltage Control Assessment" section addresses footnote items (3) and (5). Footnote item (3) is associated with MRTU Tariff Section 8.4.2(a) and footnote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

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, unconnected or unavailable from April 2009 to January 2010 as a proportion of the total spinning and non-spinning capacity procured. The average level of non-compliance was 3.9 percent of the total spinning and non-spinning reserves procured for the time period from April 2009 to January 2010**.**

Figure 18: Daily Ancillary Service Non-Compliance from April 2009 to January 2010

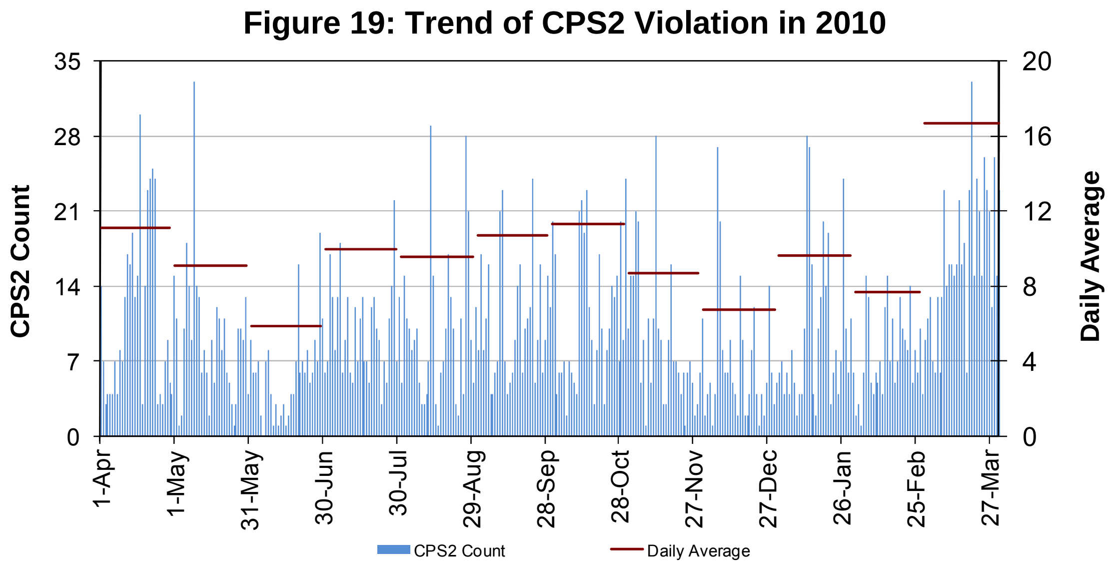


Area Control Error

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

The pattern of daily CPS2 violations is shown in Figure 19. 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).



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."[12]

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.

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

Business Practice Manuals Proposed Revision Requests[13]

For the quarter ending March 31, 2010, two BPM Proposed Revision Requests (PRR) reports were delivered to the ISO board of governors for the February 10-11, 2010 and the March 25-26, 2010 board meetings. No board meetings were held in January, 2010. The BPM Change Management reports delivered to the ISO board of governors are attached to this report as Appendices 1 and 2.

[13]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[14]

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

[14] 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[15]

At the time of submission, the full settlements process is not complete for the first calendar quarter of 2010. Therefore, this report only includes results for the months of November and December 2009 based on the monthly statements. Subsequent reports will provide this data as it becomes available.

During the months of November and December 2009 there were no under-scheduling load penalties assessed to any scheduling coordinators.

[15] 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[16]

Since the last update, the ISO has completed two of the deferred functionality items and is on track to complete a third item. The procurement of ancillary services in the hour ahead scheduling process and forbidden operating region functionality were deployed into the market on April 1, 2010 and April 15, 2010, respectively. The changes in operational ramp rates will be addressed further with the implementation of multi-stage generating (MSG) modeling scheduled to deploy in October 2010. The remaining item of the extremely long start process is currently being assessed and stakeholder discussion will begin on April 24, 2010 with a possible resolution before year end. With this updated deployment plan, the ISO requests closure on these topics with further communication provided through the standard stakeholder process and forums.

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 implemented the forbidden operating region functionality in the real-time market on April 15, 2010.

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 generating resources, 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.

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[16] 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.

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 would enable the ISO to implement the procurement of ancillary services in the hour-ahead scheduling process (See FERC Docket No. ER10-479). This functionality was deployed into the market on April 1, 2010.

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 reliable operation of its new market through the first year of MRTU 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 this year to incorporate this functionality into its tariff and market software..

Evaluation of Adjustment of Non-Priced Quantities[17]

Day-Ahead Market

The majority of market parameters that are used for adjusting non-priced quantities in the day-ahead market optimization relate to transmission constraint relaxation and adjustment of self-schedules. Since the start-up of the new market on April 1, 2009, these parameters have only rarely affected the Day-Ahead Market results. There have been no LMPs 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 are adjusted to conform to transmission limits when effective bids are available. Self-schedules are adjusted when there are no further effective economic bids. When the adjustments affect generation or import schedules, the LMPs reflect a marginal bid price in the pricing run of -$30/MWh. In the period addressed in this analysis, sufficient economic bids were generally available to enforce transmission limits without adjustments to self-schedules. An adjustment in self-schedules occurred for 11 hours on March 29, due to a temporary transmission constraint related to planned transmission maintenance in the Geysers area. LMPs in the affected area ranged from -$25 to -$31/MWh. This confirms that the mechanism for market adjustments to generation and imports self-schedules is functioning as intended.[18]

When it is necessary to relax transmission constraints to resolve congestion, the market optimization resolves these constraints by pricing violations at $5000/MW

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[17] 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."

[18] 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

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.[19] 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 1/2/10, hour ending (HE) 23, and 3/18/10, HE 20 and HE 22, the HUMBOLDT_BG corridor was relaxed by 0.1, 0.7, and 2.6 MW, respectively, due to inadequate supply in the Humboldt area during generation outages. This constraint produced a pricing run shadow price of $500/MW in each instance. LMPs for generation in the Humboldt area ranged from $548 to $555/MWh during these hours due to the most effective generation being over 99% effective in managing this constraint.

- On 1/8/10, HE 18, the ELNIDO-LAFRESA_NG nomogram was relaxed by 3 MW at a pricing run shadow price of $500/MW, when conditions for this hour did not relieve the congestion using local generation, thus producing LMPs of $554/MWh in the affected area for this hour.

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 a lack of sufficient effective 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 January

[19] See Appendix C of the ISO Tariff for further details.

through March 2010 shows similar amount of uneconomic adjustments as the previous quarter, continuous to be 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 January 1, 2010 to March 31 of 2010, 6.82 percent of the intervals had one or more adjustment of non-priced quantities in the real-time dispatch market solution. This represents a slight reduction from the 8.82 percent of the previous quarter but much lower in comparing with the 16.09 and 15.53 percent respectively of the first 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, nomograms and tie-points.

The significant reduction in the number of intervals in which non-priced quantities were adjusted with respect to the first two quarters of the new market operation since April 1, 2009 is mainly due to the modification of the real-time software since August 1, 2009 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).[20] Such relaxation of the energy

[20] 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

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 over-generation 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 first quarter of 2010 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 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.

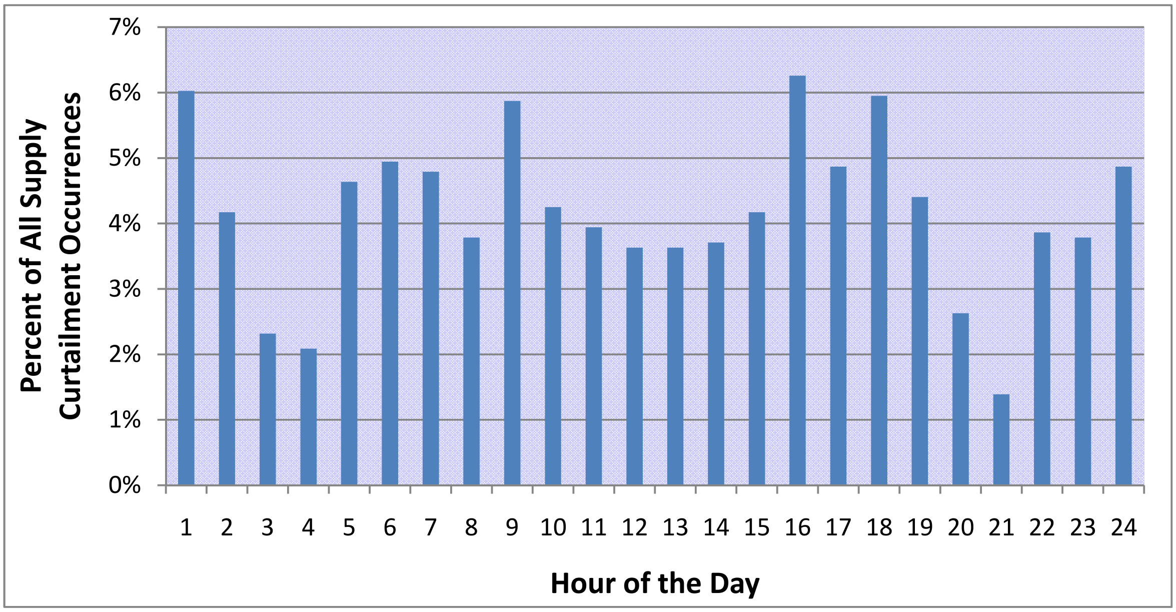
The ISO’s analysis of the first four quarters of operation of the new markets reveals that the energy self-schedule parameter settings in the real-time dispatch continue to be appropriate. The results from the first quarter of 2010 generally align with the previous three quarters of new market operation. 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/MWh. 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 in those intervals within the ending phase of 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 4.99 percent of the five-minute intervals, a reduction from the 10.48 percent of second quarter 2009, 12.26 percent of third quarter 2009 and 6.24 percent of the final quarter 2009. The noticeable reduction in comparison with the first three quarters of new market operation is due to the implementation of energy requirement relaxation reflecting the role of regulation described above. During the three-month period these adjustments occurred 32.69 percent of the time for January, 11.59 percent of the time for February and 55.72 percent of the time for March. Figure 20 shows the curtailments as a percentage of the total occurrences for different hours of day over the three-month period from January through March 2010.

The chart on the next page does show a different hour-of-the-day profile than that occurred in the first three quarters of new market operation. In the first six months of new market, 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 20 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 as it was also in previous 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.

Figure 20: Percentage of Supply Energy Adjustment of Non-Priced Quantities Curtailments by Hour



Among all the supply self-schedule curtailment intervals, 79.92 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 0.7 percent of the time (or 0.035 percent in the three-month period). The 0.035 percent in the three-month period is a significant reduction from the previous quarter and is a dramatic decrease from the first two quarters of new market operation. During these intervals, LAP prices for the over-generation area were near -$30 for 33.33 percent of intervals (or 0.01 percent of the three-month period) and 66.66 percent (or 0.02 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 load 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 January through March 2010 shows that the initial export self-schedule curtailment parameters have also been appropriate because:

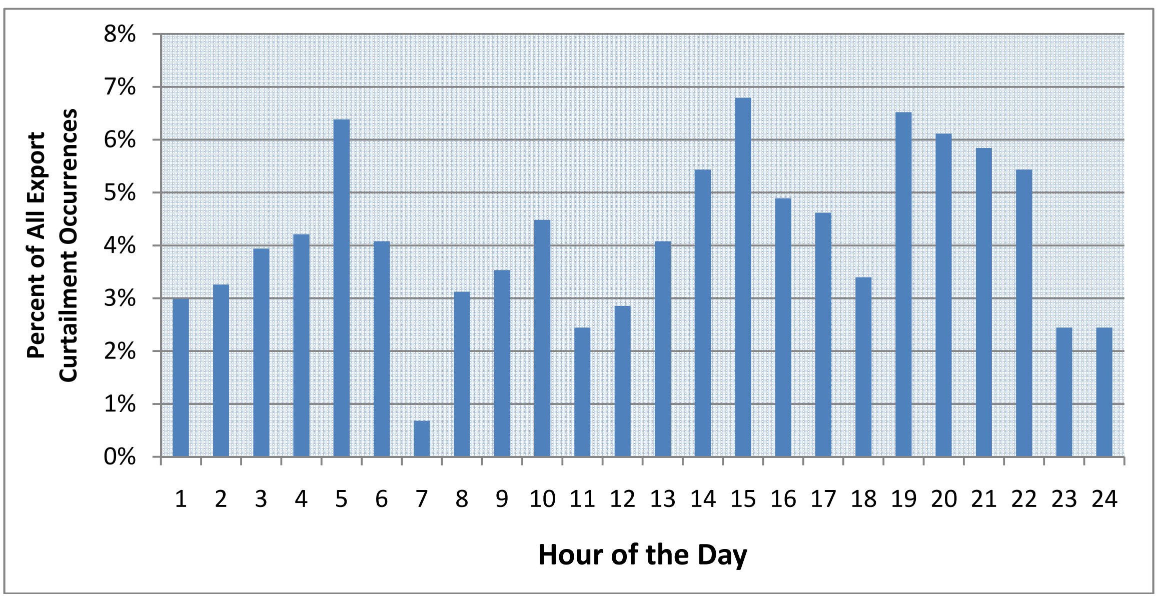
1. Self-schedule curtailment of exports has rarely occurred.
2. In instances where there were export self-schedule curtailments, the majority of intervals had pricing run LMPs which were not significantly above the $500 bid cap. Among such instances, pricing run system LAP and/or default LAP prices around $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 (2.04 percent) had some default LAP prices of at least $100 above the $500 bid cap when a downward ramping constrained resource set the price during the ending phase of 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 0.92 percent of real-time dispatch intervals had export energy uneconomic adjustments, representing a minor increase from 0.54

percent of previous quarter but remains to be a significant reduction from the 1.94 percent of the second quarter of new market operation. 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 adjustments, 11.93, 84.77, and 3.29 percent occurred in January, February and March 2010, respectively.

Figure 21shows the hourly adjustment occurrences in percent of the total adjustment occurrences over the three-month period from January 1 through March 31, 2010. As also the case for previous quarter, the chart does not show any pattern in the hour-of-the-day profile which is in contrast to the first two quarters of new market operation where export energy uneconomic curtailments are more likely to occur in peak hours.

Figure 21: Percentage of Export Energy Uneconomic Adjustments by Hour



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 incremental 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 11.52 percent of time (or 0.11 percent over the three-month period which is quite comparable with the number of occurrences in previous quarter). LAP prices in the supply-shortage area were around $500/MWh in 5.35 percent of time (or 0.05 percent over the three-month period) and above the $600/MWh level in 6.17 percent of the time (or 0.06 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 three quarters of new market operation shows that the initial parameter settings have performed as anticipated. Specifically the ISO has found that:

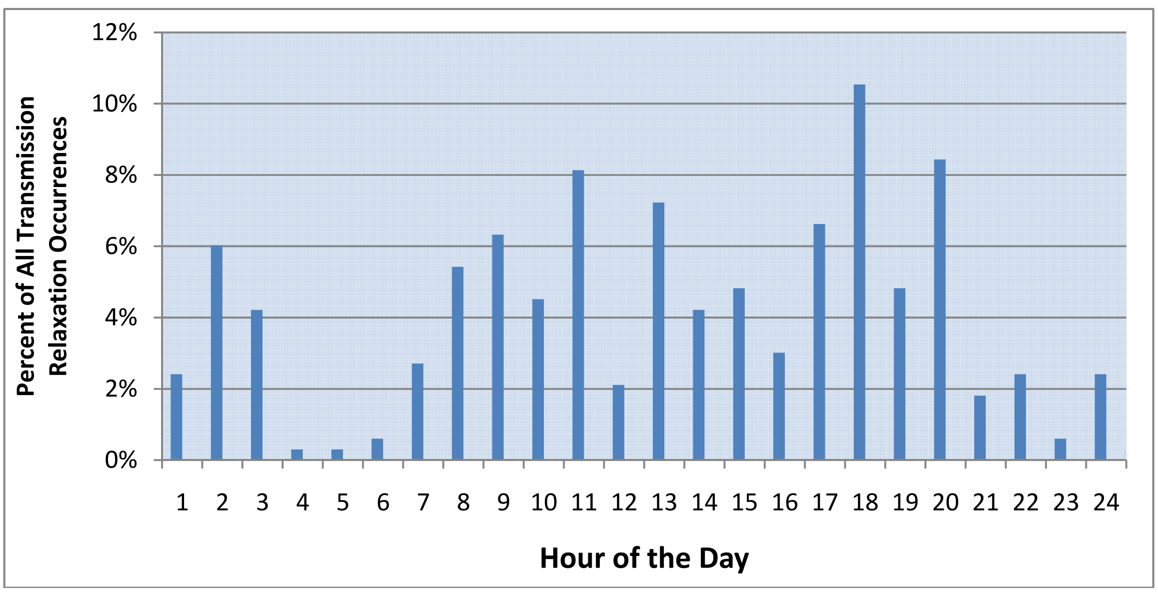
1. Transmission constraint relaxation occurred infrequently and, when it did occur, the amount of relaxation was small in most cases.
2. Among intervals with transmission constraint relaxation, locational marginal prices around the constraint were often set beyond the bid ceiling/floor range of –$30/MWh 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.[21]

The real-time market results show that transmission constraint relaxation occurred in 1.28 percent of all the five-minute intervals of the three months, less than 3.09 percent of the previous quarter. Among the five-minute intervals of the transmission constraint relaxation occurrences, 52.41, 21.99 and 25.60 percent occurred in January, February and March, respectively.

Figure 22 shows the hourly transmission constraint relaxation occurrences as a percentage of all curtailment occurrences for January through March 2010. This chart shows that transmission constraint relaxation in the market solution is more likely to occur during peak-hour intervals.

Figure 22: Hourly Transmission Constraint Relaxation



It should be noted that 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 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.

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[21] See technical bulletins at: http://www.caiso.com/2381/2381f87327f70.html

For 82.53 percent of the time intervals with transmission constraint relaxation in the real-time market solution (or 1.06 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 17.47 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 DLAP prices of several thousand dollars were observed only once, or 0.039% of time over this three-month period.

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 January, February and March of 2010, 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 RTUC 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 8636 15-minute intervals, ancillary services minimum requirement relaxation occurred in only seven 15-minute intervals or 0.081 percent of time. Three of the seven intervals are the February 14, 2010, hour ending 13, intervals 2, 3 and 4. Among these three intervals, ancillary services requirement relaxations were observed for regulation-up for the ISO expanded region. The remaining four intervals are: January 6, 2010, hour ending 9, interval 3 where regulation-up requirement are relaxed for SP-26 expanded region; January 9 2010, hour ending 19, interval 2 where regulation-down requirement was relaxed for SP-26 region; January 9 2010, hour ending 20, interval 4 where regulation-down requirement was relaxed for SP-26 region and February 27 2010, hour ending 17, interval 3 where regulation-up requirement was relaxed for SP-26 expanded 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[22]

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 6. As of April 1, 2010, the price caps no longer apply.

Table 6: Price Cap Example

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

Summary of Price Caps

Figure 23 and Table 7 show the frequency with which the price caps were applied in the different market runs that procure products subject to the price cap from January 1 through March 31. 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 324 intervals of the hour-ahead scheduling process, real-time unit commitment run, and real-time dispatch during which the price cap was applied to prices at one or more nodes, increasing by 91 compared with the fourth quarter in 2009. There was no price cap applied to the day-ahead market. As shown in Figure 23 and Table 7, the number of price caps

[22] 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.

for the real-time dispatch followed an upward trend. The number of price caps for the hour-ahead scheduling process and real-time unit commitment run dropped significantly in March.

Figure 23: Count of Price Caps

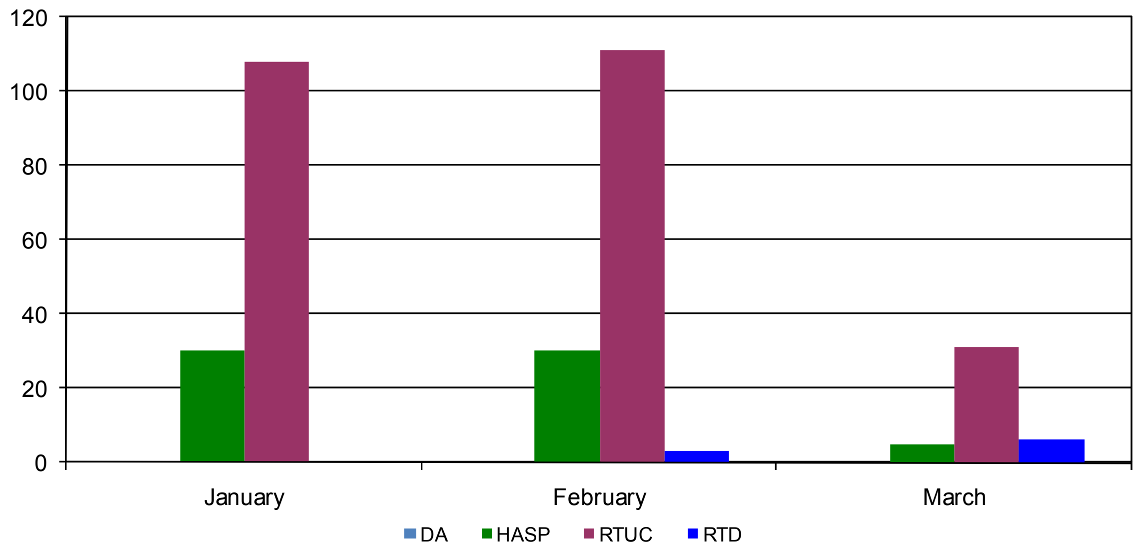

Table 7: Summary of Price Caps

Month	DA	HASP	RTUC	RTD
January	0	30	108	0
February	0	30	111	3
March	0	5	31	6
Total	0	65	250	9

Price Cap Analysis[23]

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[24].

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[25] Effect

Shift factors are used by the market in resolving congestion, where each resource is assigned a value between -1 and +1, which in general represents its effectiveness in resolving a particular constraint. The term "lossless" refers to the fact that the effectiveness factors used in the ISO market do not account for the effect of losses between their location and the congestion constraint. In the case of a radial constraint, a constraint where the resources on each side of the constraint are all equally effective at resolving it, high congestion shadow prices, in the range between the pricing run parameter for constraint relaxation and the scheduling run parameter for constraint relaxation, can result if there is a lack of otherwise economical resources and the optimization resorts to adjusting two or more units such that small amounts of losses, and thus flow on the constraint, are reduced. This effect is explained in more detail in the following technical bulletin: http://www.caiso.com/23ce/23cec5cd70160.pdf.

Notable cases where this phenomenon occurred were on January 6, 2010 with congestion on the SCE import limit due to a loss of a resource, on January 31, February 5 and 13, 2010 with congestion on the SCE import limit due to operating bias.

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[23] 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.

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

[25] 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.

A notable case where this occurred was on the LA- Fresa branch on January 4, 2010. This event was due to line outages and reduced line limits for reliability margin.

Business Practice Manuals
Change Management Report
February 3, 2010

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

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

Date: February 3, 2010

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 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.

The ISO inaugurated the public change management process for business practice manuals 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 January 12, 2010, 31 proposed revision requests (PRRs) were active in the BPM change management system, 100% of which were submitted by the ISO. These 31 active PRRs impact the following BPMs:

26	Settlements and Billing
1	Market Operations
1	Market Instruments
3	Congestion Revenue Rights

No BPM decisions are under stakeholder appeal.

PROCESS OVERVIEW

The ISO held the monthly BPM change management stakeholder meeting on December 18, 2009. The meeting, which was conducted by conference call, included 10 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 January 12, 2010, 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 January 12, 2010;

- Reflects those PRRs upon which Management has posted its final decision for the period November 21, 2009 through January 12, 2010; 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.

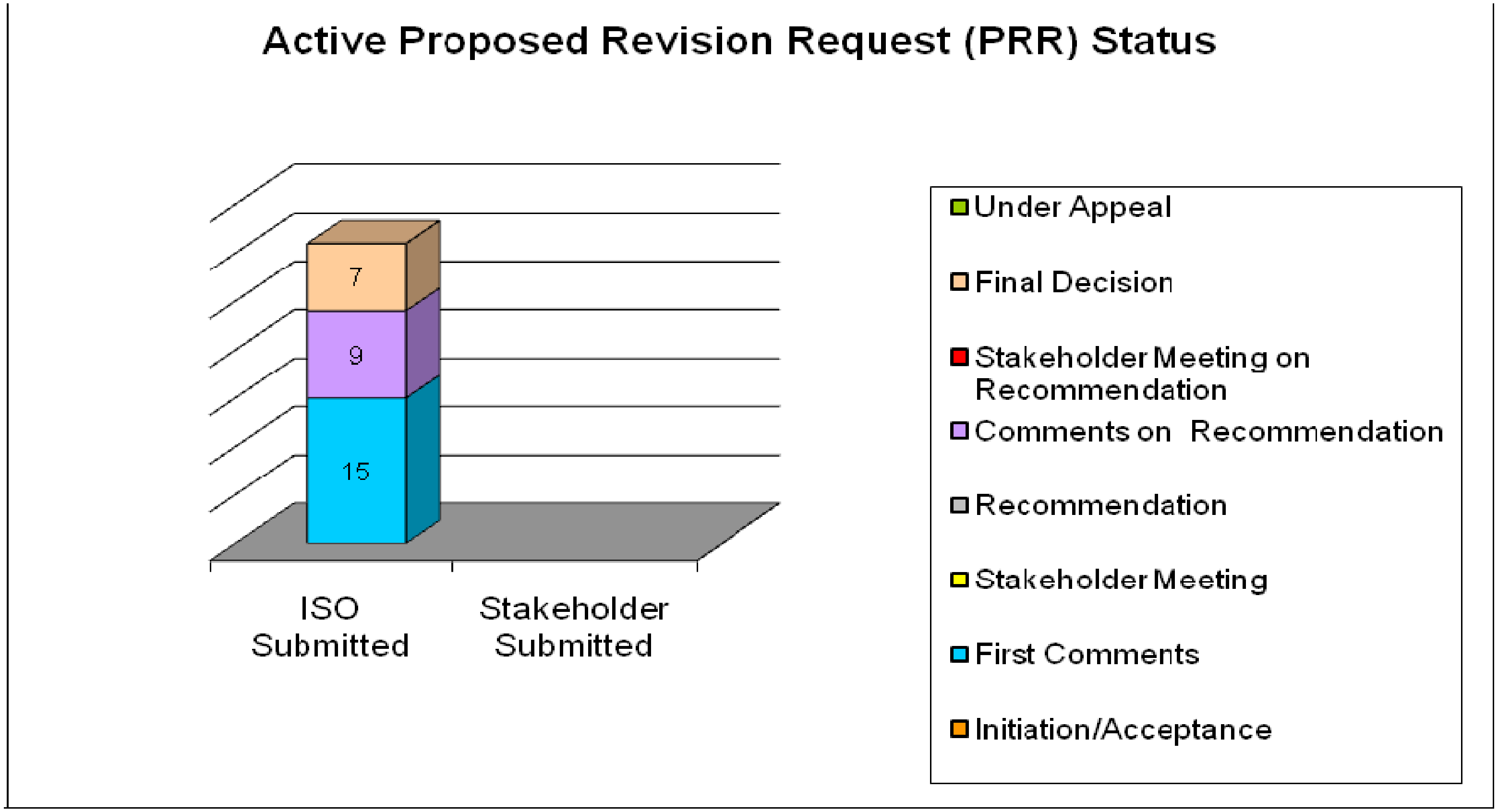
- Twenty-three of the active PRRs were submitted into the electronic system by the ISO on an emergency basis and all of those PRRs related to the Settlements and Billing BPM.

- A PRR report as of January 13, 2010 is included as Attachment 2. This report summarizes PRRs added to the BPM change management system since the December Board meeting.

California ISO
Your Link to Power

Board Update: BPM Change Management Process

Attachment 1



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

Active PRR Stage	# of PRRs
First Comments	15
Comments on Recommendation	9
Final Decision	7
Total	**31**

Business Practice Manual (BPM)	# of PRRs
Congestion Revenue Rights	3
Market Instruments	1
Market Operations	1
Settlements and Billing	26
Total	**31**

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	PRR Decision
Accept	99	Inconsistent Use of Minimum/Maximum Days; Lack of explanation of how days are determined	Final Decision	The California ISO adopts its recommendation with minor modifications as follows: In addition to the change in the number of days from 48 to 50 in Section 4.1, the California ISO will also make an addtional change to Section 6.1 to reflect an additional seven (7) days of extrapolated transactions instead of five (5) and to Section 6.2 to reflect the factor of 14-17 days for monthly charge codes in EAL component #4.
Accept	100	Market Operations BPM changes due to Simplified ramping rules implementation	Final Decision	The California ISO adopts its recommendation as submitted. CAISO will adopt the language proposed in the PRR. Next version of BPM will contain the change proposed in this PRR
Accept	102	Update BPM Configuration Guide for Start Up and Minimum Load Cost to accommodate implementation defect for Pumping Cost sign convention	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	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	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	104	Revisions to ensure consistency with RMR contract and tariff requirements	Final Decision	The California ISO adopts its recommendation as submitted CAISO will adopt the language proposed in this PRR. Next version of BPM will contain the updated proposed in this PRR.
Accept	105	New Charge Code 722 for Participating Intermittent Resources Program (PIRP) required as a result of Payment Acceleration	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation

Accept	106	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources Program (PIRP) under Payment Acceleration.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation as follows: The BPM content is consistent with FERC's November 9, 2009 order accepting the proposed tariff amendment to modify the Payment Acceleration Program for CRR/PIRP In response to comments submitted by Viasyn, this particular PRR 106 was a Category B emergency change to accommodate the above mentioned tariff amendment. Viasyn's proposed remedy (A) has impacts to all market participants and remedy (B) has impacts to other PIR program participants; both of which would require an additional Tariff amendment preceded by a proper stakeholdering effort which go beyond the scope of this particular PRR.
Accept	107	Update the BPM document and Configuration to reflect new PIRP charge code in the Participating Intermittent Resources charge group	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation with updates noted during the 11/24 BPM Stakeholder meeting as well as a Market Notice provided on November 17, 2009. PRR 107 was provided to communicate the addition of a new CC 722 Intermittent Resources Net Deviation Reversal. There is no change to the calculation logic configured for CC 4999 as the new CC 722 was added to an existing bill determinant input for the Participating Intermittent Resources charge group. Therefore, the BPM update should have been categorized as a language-only change as opposed to a configuration-impacted change as shown in documentation provided previously. The version number and effective date for the CC 4999 has been updated accordingly to 5.0a and April 1, 2009, respectively and revision attached to the PRR.
Accept	108	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources Program (PIRP) in CC 6477 under Payment Acceleration.	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	109	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources (PIR) under Payment Acceleration.	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation

Final Decisions Posted 11/21/2009 - 1/12/2010

Accept	110	Updated the BPM document and Configuration to reflect the treatment of Participating Intermittent Resources (PIR) under Payment Acceleration.	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	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	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	112	Termination of BPM Configuration guide for CC 6728	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	113	Update BPM Configuration guide for CC 6790 for payment acceleration	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	114	New BPM Configuration guide for CC 6791 for payment acceleration	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	115	Update BPM Configuration guide for CC 6798 for payment acceleration	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	116	Update BPM Configuration Guide for CC 6620 Bid Cost Recovery Settlement to correct typographical error.	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	117	Update the BPM document to be consistent with current configuration and in response to Participant issue ticket	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	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	Final Decision	The ISO will adopt the BPM changes as proposed in the Recommendation
Accept	119	Update BPM Configuration guide for CC 382 High Voltage Wheeling Allocation to accommodate Wheeling Non-PTO data submittal - Payment Acceleration	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.

Accept	120	Update BPM Configuration guide for CC 383 Low Voltage Wheeling Allocation to accommodate Wheeling Non-PTO data submittal - Payment Acceleration	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	121	Update to Definitions to Incorporate Already-Effective CAISO Tariff Revisions	Final Decision	The ISO is adpoting these minor BPM revisions to conform to the tariff. In addition to the changes requested in the BPM PRR 121, we are recommending changes to the defined terms and definitions of "Exceptional Dispatch ICPM" and "Projected Proxy Bid" to conform more accurately to the CAISO tariff. These changes were inaccurately described in the original BPM PRR request.
Accept	122	Update to Definitions to Incorporate CAISO Tariff Revisions Regarding Payment Acceleration	Final Decision	The ISO is adopting these minor BPM revisions to conform to the tariff. In addition to the changes requested in the BPM PRR 122, we are recommending changes to the definitions of "Incremental Change" to conform to the tariff. This change was inadvertently left off the original BPM PRR request.
Accept	123	Update to Definitions to Incorporate CAISO Tariff Revisions Regarding Standard Capacity Product	Final Decision	The ISO adopts its recommendation as submitted.
Accept	124	Update to Definitions to Incorporate Pending CAISO Tariff Revisions	Final Decision	The ISO adopts its recommendation with modifications as follows: The ISO is adopting these minor BPM revisions to conform to the tariff. In addition to the changes requested in the BPM PRR 124, we are recommending changes to the definition of "All Constraints Run (ACR)" to conform to the CAISO tariff. This change was inadvertently left off the original BPM PRR request.
Accept	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	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.

Accept	126	Update the BPM and Configuration for CC 4537 to reflect the new tariff requirements for calculating the Billable Quantity.	Final Decision	The ISO is adopting the BPM changes as summarized in the Recommendation with a revised effective date of 6/1/2010 rather than 1/1/2010. This revision is a result of a FERC Order regarding the associated proposed tariff changes in Docket ER10-188-000. The December 30, 2009 FERC Order has conditionally accepted the market usage forward energy (MUFE) proposed rate changes and suspended the implementation of the revised calculation for GMC MUFE CC 4537 as specified in the BPM Configuration Guide version 5.1. The charge will become effective on June 1, 2010 and will be subject to refund pending evidentiary hearing and settlement judge procedures. A revised version of the BPM Configuration Guide for CC 4537 v5.1 showing the updated effective start and end dates has been attached to the PRR. The current MUFE GMC charge, associated tariff provisions, and BPM Configuration Guide version 5.0 will remain in effect until June 1, 2010
Accept	127	Introduce BPM Configuration Guide for the new settlements Charge Code 6455 Declined Hourly Pre-Dispatch Penalty Settlement configuration	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation
Accept	128	Introduce BPM Configuration guide for the new settlements Charge Code 6457 Declined Hourly Pre-Dispatch Penalty Allocation configuration.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	129	Update the BPM Configuration Guide for Real Time Energy Pre-calculation to reflect new successor Charge Code and ensure consistency with configuration.	Final Decision	The ISO will adopt the BPM change as proposed in the recommendation.
Accept	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.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.

Accept	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	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Total		**33**		

BPM Proposed Revision Requests (PRR): Summary Report

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Congestion Revenue Rights	155	Clarifications of language on OBAALSE Eligible Quantity, PNP validation, Load Migration exclusion, and sale of CRR using SRS	Revised various sections to clarify existing language	A	1/6/2010	California ISO	Normal	Comment Period	Stakeholder Meeting
Congestion Revenue Rights	154	The elimination of Pre-Auction bid path submission requirements and Process to reevalutate CRR Credit Requirements under Extraordinary circumstances	Revised Sections 9.3, 11.2, and H.B.4	C	1/5/2010	California ISO	Normal	Comment Period	Stakeholder Meeting
Congestion Revenue Rights	153	Process for Handling Disconnected Pnodes for CRR Purposes	Addition of Section 15	C	1/5/2010	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	152	Update BPM Configuration Guide for Residual Unit Commitment (RUC) Capacity Payment Rescission Settlement Charge Code 6824 to utilize RUC No Pay quantity calculated by RUC no Pay Quantity Pre-calculation	BPM Configuration Guide for Residual Unit Commitment (RUC) Capacity Payment Recission Settlement Charge Code 6824	A	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	151	Update BPM Configuration Guide language for No Pay Spin Reserve Settlement (CC 6224) for Settlement integration of compliance calculations	BPM Configuration Guide for CC 6224 No Pay Non Spin Reserve Settlement	A	12/22/1009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	150	Update BPM Configuration Guide language for No Pay Spin Reserve Settlement (CC 6124) for Settlement integration of compliance calculations	BPM Configuration Guide for CC 6124 No Pay Spin Reserve Settlement	A	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	149	Update BPM Configuration Guide for RUC Net Amount Pre-calculation to utilize RUC No Pay quantity calculated by RUC No Pay quantity Pre-calculation	BPM Configuration Guide for RUC Net Amount Pre-calculation	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	148	Update BPM Configuration Guide for RTM Net Amount Pre-calculation to utilize outputs from the Spin and Non Spin No Pay Quantity Pre-calculation	BPM Configuration Guide for RTM Net Amount Pre-calculation	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	147	Update BPM Configuration guide to accommodate the new input variable from the BPM Configuration Guide Spin and Non-Spin No Pay Quantity Pre-Calculation	BPM Configuration Guide Ancillary Services Pre-Calculation	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting

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

Settlements and Billing	146	New BPM Configuration Guide required for a Spin Non-Spin No Pay Quantity Pre-calculation effective 2/01/2010	BPM Configuration Guide for Spin Non-Spin No Pay Quantity Pre-calculation	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	145	New BPM Configuration Guide required for a RUC No Pay Quantity Pre-calculation	BPM Configuration Guide for RUC No Pay Quantity Pre-calculation	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	144	Update the BPM Configuration Guide for Charge Code 4989 to reflect the addition of Low Voltage Access Charge group to the daily rounding calculation	CG CC 4989 Daily Rounding Adjustment Allocation	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	143	New BPM Configuration Guide for CC 375 to disburse collected Low Voltage Access Charge (LVAC) amount to a Non-Load-Serving Participating Transmission Owner (NLS PTO)	BPM CG CC 375 Low Voltage Access Revenue Payment	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	142	New BPM Configuration Guide for CC 373 to assess Low Voltage Access Charge (LVAC) for a Non-Load-Serving Participating Transmission Owner (NLS PTO)	BPM CG CC 373 Low Voltage Access Charge Settlement	B	12/22/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	141	Update BPM Configuration Guide for Start-Up and Minimum Load Cost Pre-calculation to reflect actual calculation of the Period SUC Flag for IFM, RUC, and RTM	BPM Configuration Guide for Start-Up and Minimum Load Cost Pre-calculation	A	12/16/2009	California ISO	Normal	Comment Period	Stakeholder Meeting
Settlements and Billing	140	Updated BPM Configuration Guide for Charge Code 8827 to reflect the use of CAISO Metered Demand per tariff language 11.5.2.3	BPM Configuration Guide for Charge Code 8827 Monthly NRSS Resource Adequacy Standard Capacity Product MD Allocation	A	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	139	Updated BPM Configuration Guide for Charge Code 8826 to reflect the use of CAISO Metered Demand per tariff language 11.5.2.3	BPM Configuration Guide for CC 8826 Monthly RA Standard Capacity Product Measured Demand Allocation	A	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting

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.

Settlements and Billing	138	Updated BPM Configuration Guide for Charge Code to ensure positive non availability charge quantity for NRSS resources.	BPM Configuration Guide for Charge Code 8825 Monthly NRSS Resource Adequacy Standard Capacity Product Settlement	A	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	137	Update BPM Configuration Guide for CC 8824 to ensure positive non availability charge quantity for generating resources.	BPM Configuration Guide for Charge Code 8824 Monthly Resource Adequacy Standard Capacity Product Settlement	A	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	136	Updated BPM Configuration Guide to include Monthly NRSS RA Standard Capacity Product Metered Demand Allocation as a successor charge code.	BPM Configuration Guide for Charge Code 8821 Monthly NRSS Resource Adequacy Standard Capacity Product Allocation	A	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	135	Updated BPM Configuration Guide to remove Measured Demand over Control Area Precalculation as a predecessor.	BPM Configuration Guide for Charge Code 8820 Monthly Resource Adequacy Standard Capacity Product Allocation	A	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	134	Updated BPM Configuration Guide for Standard Capacity Product Precalculation to include the availability for the substituted resources and to calculate an intermediate Metered CAISO Demand bill determinant.	BPM Configuration Guide for Standard Capacity Product Pre-calculation	B	12/3/2009	California ISO	Emergency	Comment Period	Stakeholder Meeting
Market Instruments	133	Start Up and Minimum Load changes for Cost Operions in Master File	Attch G Registered Cost Option	A	12/2/2009	California ISO	Normal	Comment Period	Stakeholder Meeting

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.

Business Practice Manuals
Change Management Report
March 17, 2010

Memorandum

To: ISO Board of Governors

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

Date: March 17, 2010

Re: **Informational 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 to inform the ISO Board of Governors on the status of the business practice manual change requests submitted by stakeholders and the California Independent System Operator Corporation.

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 February 25, 2010, 57 proposed revision requests (PRRs) were active in the BPM change management system, of which, 100% were submitted by the ISO. These 57 active PRRs impact the following BPMs:

34	Settlements and Billing
6	Market Operations
5	Definitions and Acronyms
3	Market Instruments
3	Congestion Revenue Rights
2	Compliance Monitoring
1	Managing Full Network Model
1	Metering
1	Outage Management
1	SC Certification and Termination

No BPM decisions are under stakeholder appeal.

PROCESS OVERVIEW

The ISO held the monthly BPM change management stakeholder meeting on February 23, 2010. The meeting, which was conducted by conference call, included nine 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 February 25, 2010, 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 February 25, 2010;
- Reflects those PRRs upon which Management has posted its final decision for the period January 12, 2010 through February 25, 2010; and
- Includes PRRs currently under stakeholder appeal, the stakeholder positions on rejected PRRs, and the reasons for rejection.

The following is additional relevant information:

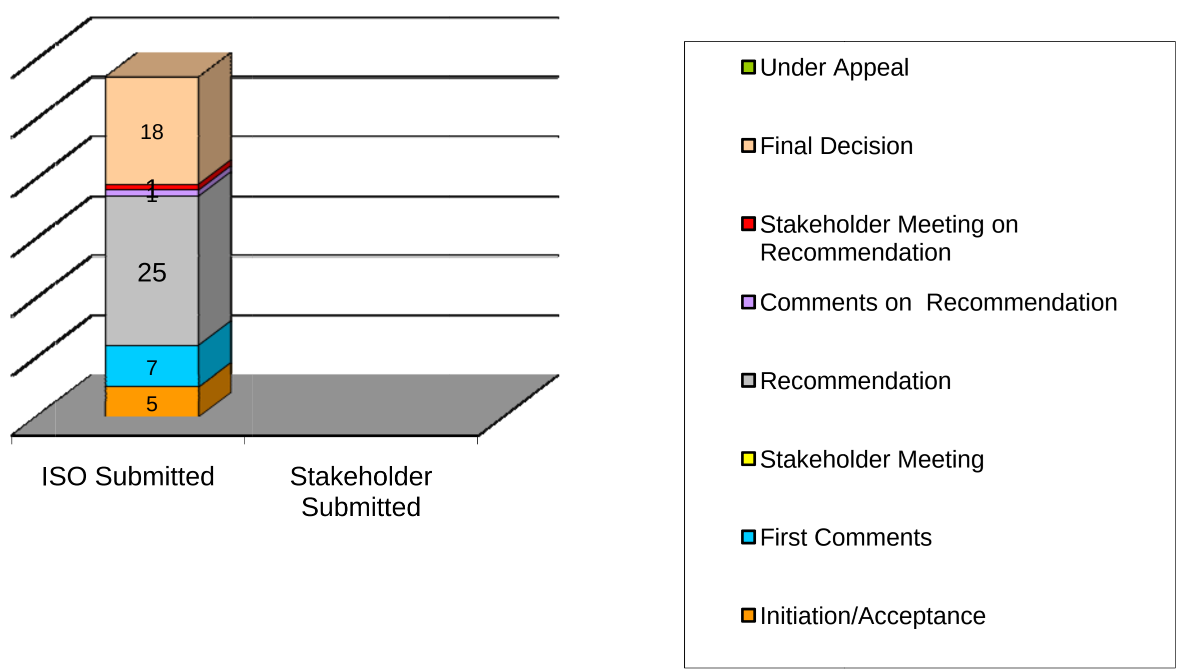
- No PRRs are under stakeholder appeal.
- Fourteen of the active PRRs were submitted into the electronic system by the ISO on an emergency basis and all of those PRRs related to the Settlements and Billing BPM.
- A PRR report as of February 25, 2010 is included as Attachment 2. This report summarizes PRRs added to the BPM change management system since the February Board report.

California ISO
Your Link to Power

Board Update: BPM Change Management Process
March 25-26, 2010 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**

Active PRR Stage	# of PRRs
First Comments	7
Comments on Recommendation	1
Final Decision	18
Stakeholder Meeting on Recommendation	1
Recommendation	25
Initiation/Acceptance	5
Total	**57**

Business Practice Manual (BPM)	# of PRRs
Compliance Monitoring	2
Congestion Revenue Rights	3
Definitions and Acronyms	5
Managing Full Network Model	1
Market Instruments	1
Market Operations	6
Metering	1
Outage Management	1
Scheduling Coordinator Certification and Termination	1
Settlements and Billing	34
Total	**57**

Accepted or Rejected	PRR Number	PRR Title	Current PRR Status	PRR Decision
Accept – pending management approval	132	Market Operations BPM Updates related to PIRP	Final Decision	The BPM language is being forwarded to CAISO senior management for review and approval. The redlined final language incorporates comments from stakeholders received during the open comment periods and at the BPM change management monthly meetings. The BPM will be updated upon approval of senior management. The redlined final language is attached to this PRR 132.
Accept	133	Start Up and Minimum Load changes for Cost Options in Master File	Final Decision	The Market Instruments BPM v4 has adopted the changes set forth in PRR 133 for Startup and Minimum Load changes
Accept	134	Updated BPM Configuration Guide for Standard Capacity Product Pre-calculation to include the availability for the substituted resources and to calculate an intermediate Metered CAISO Demand bill determinant.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	135	Updated BPM Configuration Guide to remove Measured Demand Over Control Area Pre-calculation as a predecessor.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	136	Updated BPM Configuration Guide to include Monthly NRSS RA Standard Capacity Product Metered Demand Allocation as a successor charge code.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	137	Updated BPM Configuration Guide for CC 8824 to ensure positive non availability charge quantity for generating resources.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.

Accept	138	Updated BPM Configuration Guide for Charge Code to ensure positive non availability charge quantity for NRSS resources.	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	139	Updated BPM Configuration Guide for Charge Code 8826 to reflect the use of CAISO Metered Demand per tariff language 11.5.2.3	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	140	Updated BPM Configuration Guide for Charge Code 8827 to reflect the use of CAISO Metered Demand per tariff language 11.5.2.3	Final Decision	The ISO will adopt the BPM changes as proposed in the recommendation.
Accept	163	Modify Schedule for Developing Unified Planning Assumptions and Study Plan	Final Decision	ISO considered stakeholder comments. ISO will adopt the Recommendation PRR as posted.
Accept	164	Modify schedule for conducting technical studies, posting study results and PTO submission of reliability projects	Final Decision	This PRR has been adopted as recommended with a minor modification. In order to be consistent with the changes in this PRR we made an additional change in section 2.1.2.1 per a comment from SCE. We deleted the October 15 date and modified it by saying the PTO's will have thirty business days to submit their reliability proposals from the day the ISO posts its reliability assessment. This content is consistent with this PRR.
Accept	165	Modify the name of the sub-regional planning group and clarify ISO collaboration activities	Final Decision	No stakeholder comments received. The ISO adopts its Recommendation as posted.
Total			**12**	

BPM Proposed Revision Requests (PRR): Summary Report

Attachment 2

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Definitions and Acronyms	200	Update to Definitions to Incorporate ISO Tariff Revisions Regarding Transmission Constraints	No section, only definitions	A	2/25/2010	California ISO	Normal	Initiation Acceptance	Initial Comments Period
Definitions and Acronyms	199	Update to Definitions to Incorporate ISO Tariff Revisions Regarding Scarcity Pricing	No section, only definitions	A	2/25/2010	California ISO	Normal	Initiation Acceptance	Initial Comments Period
Definitions and Acronyms	198	Update to Definitions to Incorporate ISO Tariff Revisions Regarding Proxy Demand Resource	No section, only definitions	A	2/25/2010	California ISO	Normal	Initiation Acceptance	Initial Comments Period
Definitions and Acronyms	197	Update to Definitions to Incorporate ISO Tariff Revisions Regarding Order 719 Market Monitoring Compliance	No section, only definitions	A	2/25/2010	California ISO	Normal	Initiation Acceptance	Initial Comments Period

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	196	Update to Definitions to Incorporate ISO Tariff Revisions Regarding Late Payment Enforcement	No section, only definitions	A	2/25/2010	California ISO	Normal	Initiation Acceptance	Initial Comments Period
Settlements and Billing	195	New BPM Configuration Guide for CC 5025 to assess financial penalty to Market Participants who fail to post collateral within the prescribed timeframe	BPM CG CC 5025 Collateral Late Payment Penalty	B	2/17/2010	California ISO	Urgent	Comment Period	Stakeholder Meeting
Settlements and Billing	194	New BPM Configuration Guide for CC 5024 to assess financial penalty to Market Participants who are late in paying their invoices	BPM CG CC 5024 Invoice Late Payment Penalty	B	2/17/2010	California ISO	Urgent	Comment Period	Stakeholder Meeting

BPM Proposed Revision Requests (PRR): Summary Report

Attachment 2

BPM TITLE	PRR #	PRR TITLE	BPM SECTION	CATEGORY	DATE POSTED	PRR OWNER	PRIORITY	CURRENT STATUS	NEXT STEP
Settlements and Billing	193	Update Settlements & Billing BPM Main Body for Late Payment Penalties	Settlements & Billing BPM Main Body section 6.1.1.2, section 6.3.4 and Exhibit 8-2	B	2/17/2010	California ISO	Urgent	Comment Period	Stakeholder Meeting
Settlements and Billing	192	Update the BPM Configuration Guide for RT Price Pre-calculation to reflect a change in the calculation of MSS NET Price	BPM CG PC Real Time Price	B	2/17/2010	California ISO	Emergency	Comment Period	Stakeholder Meeting
Settlements and Billing	191	Updates to BPM Configuration Guide for C 6044 to incorporate FERC Compliance Filing Acceptance Order	CC 6044 Interim Scheduling Charge for Under-Scheduled Load	B	2/17/2010	California ISO	Emergency	Comment Period	Stakeholder Meeting
Compliance Monitoring	190	BPM clean-up to remove sections that have been integrated into Settlements System.	Sections 4, 6, 7 and 8. Attachments I, J, and K	A	2/23/2010	California ISO	Normal	Comment Period	First Comments
Market Operations	189	Five-Day Price Correction Time Horizon	8.1.6.2	C	2/10/2010	California ISO	Normal	Comment Period	Stakeholder Meeting

CERTIFICATE OF SERVICE

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

Dated at Folsom, California this 30th day of April, 2010.

/s/ Anna Pascuzzo

Anna Pascuzzo