Exceptional Dispatch

Review and Assessment

WHITE PAPER

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Exceptional Dispatch

Review and Assessment White Paper

Table of Contents

1. Executive Summary

This White Paper provides an overview of Exceptional Dispatches issued by the California Independent System Operator (ISO) between April 1, 2009 and March 30, 2010. Exceptional Dispatch is a manual instruction from the ISO to a generator to manage local or system problems that may not have been incorporated in ISO market algorithms. As described in this White Paper, the ISO has implemented multiple improvements with the ISO software to account for more of these issues. The various changes made to date have been effective in increasing market efficiency, reducing Exceptional Dispatch and additional improvements are scheduled for the future. Some stakeholders have suggested that the creation of new market products may reduce the need for Exceptional Dispatch. Based upon the ISO's analysis, the ISO has concluded that the development of new products specifically designed to reduce the frequency of Exceptional Dispatch is not warranted.

The ISO issues this White Paper as part of the stakeholder process described in FERC order 126 FERC ¶ 61,150.[1] The February 20 Order, among other things, (1) encouraged the ISO to continue to work with the stakeholders to develop market-based solutions to address Exceptional Dispatch, (2) required the ISO to report on the status of the Exceptional Dispatch stakeholder process every 120 days, (3) directed the ISO to submit a proposed structure for the implementation of competitive procurement of voltage support, and (4) required the ISO to submit various reports on Exceptional Dispatch.

FERC clarified its direction to the ISO in its September 2, 2009 order,[2] by stating that, while the ISO is "working to identify and develop any appropriate market products and/or modeling or software solutions that could limit the need for Exceptional Dispatch going-forward, the Commission notes that it does not favor any one market product or solution over any other market product or solution. Thus, the Commission encourages the stakeholders and the ISO to identify and develop the most appropriate market products and/or solutions that are needed to timely eliminate reliance on Exceptional Dispatch."[3]

The ISO has been working with stakeholders since September 2009 to share information on Exceptional Dispatch with stakeholders and understand their concerns. In response to stakeholder comments, the ISO has enhanced its reporting metrics and held regular stakeholder meetings. Stakeholder meetings have been held on September 29, 2009. December 9, 2009 and will be held on June 17, 2010. In the last round of written stakeholder comments, several stakeholders requested that the ISO not prematurely jump to a conclusion that new market products are required to reduce Exceptional Dispatch and instead continue to study the potential need for new products. The ISO has listened and this White Paper provides additional analysis on whether new market products are warranted. Many stakeholders have commented that they believe that the ISO is making good progress in reducing Exceptional Dispatch, and that the ISO's ongoing efforts continue to produce positive results. In response to these comments, the ISO continues to develop and implement measures to reduce Exceptional Dispatches.

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[1] *California Independent System Operator Corp.*, 126 FERC ¶ 61,150 (2009) in Docket Nos. ER08-1178-000 and EL08-88-000, http://www.caiso.com/235b/235b938e68860.pdf

[2] *Cal. Indep. Sys. Operator Corp.,* 128 FERC ¶ 61,218 (2009) (September 2, 2009 Order), http://www.caiso.com/241d/241d9dee3ea40.pdf

[3] *Id.*at P.51, fn.67.

Exceptional Dispatches are issued to address reliability and operational requirements that cannot be adequately managed by ISO market software at this time. The ISO is committed to reducing reliance on exceptional dispatch to the extent possible. During this stakeholder process, the ISO has explored the reasons underlying exceptional dispatch, identified appropriate modeling or software solutions, and analyzed the potential impact new market products might have to reduce the need for exceptional dispatch going forward. The eventual goal is that exceptional dispatches would become rare and infrequent, or necessary to address unanticipated conditions and circumstances that cannot reasonably be incorporated into the market.

Since start-up, the ISO has taken numerous actions to reduce exceptional dispatch. A reduction in exceptional dispatch is evident from the trend information presented which is briefly summarized here:

1. **MWh Volume Decline**. Exceptional Dispatch volume in the DA and RT Markets declined by 76% from a monthly average high of 6,077 MWh per day during July-Dec 2009 to a much lower monthly average of 1,474 MWh in Jan-Mar 2010. See Figures 1 & 2.

2. **Percentage of Load Decline**. Exceptional Dispatch declined as a Percentage of Load by 71% from a monthly average high of 0.87% of load during July-Dec 2009 to a much lower monthly average of 0.25% of load in Jan-Mar 2010. See Figure 3.

3. **Total Hours Decline**. Exceptional Dispatch hours in the DA and RT markets declined by 73% from a monthly average high of about 5,491 hours in July-Dec 2009 to a much lower monthly average of 1,494 hours in Jan-Mar 2010. See Figures 4 & 5.

4. **Frequency of Occurrence Decline**. Exceptional Dispatch declined in frequency by 67% from a monthly average high of 756 exceptional dispatches in July-Dec 2009 to a much lower monthly average of 249 exceptional dispatches in Jan-Mar 2010. See Figure 6.

5. **Frequency of Exceptional Dispatch MWh to Cleared MWh (Ratio). Day-Ahead:** Exceptional Dispatch declined as the ratio of Exceptional Dispatch MWh to Cleared MWh by 65% from a monthly average high of 0.38% in July-Dec 2009 to a much lower monthly average of 0.13% in Jan-Mar 2010. **Real-Time:** the ratio of Exceptional Dispatch MWh to Cleared MWh declined by 69% from a monthly average high of 2.60% in July-Dec 2009 to a much lower monthly average of 0.80% in Jan-Mar 2010. See Figures 7 & 8.

6. **DA Energy Volume Decline**. Energy volumes associated with Day-Ahead Unit Commitments from Exceptional Dispatch have declined by over 80% from a monthly average high of 319 MW during July-Dec 2009 to a much lower monthly average of 57 MW in Jan-Mar 2010. See DMM Figure 1.13 in Section 4.8 of this White Paper.

7. **Cost Decline**. Exceptional Dispatch uplift costs declined by 79% from a monthly average high of $532,860 during July-Dec 2009 to a much lower monthly average of $109,504 in Jan-Mar 2010. Pre-dispatch Instructed Imbalance Energy (IIE) costs declined by 91% from a monthly average high of $102,406 during July-Dec 2009 to a much lower monthly average of $9,266 in Jan-Mar 2010.

2. Periodic Reports and Metrics

Per the February 20 Exceptional Dispatch Order, FERC directed the ISO to report on the frequency, volume, costs, causes, and degree of mitigation of exceptional dispatches. The 60-day report cycle was revised in the September 2 Order (P 12) to occur every 30 days on a monthly basis per ISO request (P 263) with two reports filed—one on the 15th of the month and one on the 30th of the month. In its May 4 order,[4] FERC accepted the ISO's approach for monthly reporting (May 4 Order). The twice-monthly Exceptional Dispatch Informational Reports described below meet this requirement.

2.1. Monthly Exceptional Dispatch Informational Reports

The ISO publishes[5] monthly Exceptional Dispatch reports which provide Market Participants with comprehensive data on the frequency, volume and cost of exceptional dispatches initiated within the California ISO Balancing Authority Area. Reports are published monthly on the 15th and 30th of every month. The report filed on the 15th of each month provides frequency and volume information for the most recent month for which is had this data. The report filed on the 30th of each month, includes cost data for the most recent month for which it has settlement quality data.

Table 1 Report. This report provides information on the frequency, quantity, and duration of exceptional dispatches. The report is based on a template specified in the September 2 Order as modified by the May 4 Order. Each line item entry is a summary of exceptional dispatches classified by (1) the reason for the exceptional dispatch; (2) the location of the resource by Participating Transmission Owner ("PTO") service area; (3) the Local Reliability Area ("LRA") where applicable; (4) the market in which the exceptional dispatch occurred (day-ahead vs. real-time); and (5) the date of the exceptional dispatch. For each classification the following information is provided: (1) Megawatts (MW); (2) Commitment (3) Inc or Dec (4) Hours; (5) Begin Time; and (6) End Time. Appendix A to the Table 1 Exceptional Dispatch Report contains three illustrative examples of how exceptional dispatch activity is captured in the report.

Table 2 Report. The Table 2 Report contains all the Table 1 Report fields in the same format, but adds ten additional columns to the report which include the six listed above as well as: (7) Total Volume (MWh); (8) Min Load Cost; (9) Start Up Cost; (10) Charge Code "CC" CC6470; (11) Exceptional Dispatch Volume (MWh INC/DEC); (12) CC6470 INC; (13) CC6470 DEC; (14) CC6482; (15) CC6488; and (16) CC6620.

- Appendix A: Explanation by Example. This appendix contains three detailed illustrative examples, based on fictitious data due to confidentiality, of how each data field in a report line item entry is determined.

- Appendix B: Price Impact Analysis. In the September 2 Order, FERC directed the ISO to conduct a price impact analysis on two distinct pricing nodes for the entire reporting period. The two pricing nodes must be the most impacted by the exceptional dispatch

[4] *California Independent System Operator Corp.*, 131 FERC ¶ 61,100 (2010),docket Nos. ER08-1178-000 and EL08-88-000, http://www.caiso.com/278d/278d5e5f2c4a0.pdf.

[5] ISO Monthly Exceptional Dispatch Reports, http://www.caiso.com/241d/241dca223c760.html

instructions and must belong to two different load aggregation points (LAPs). Each month, the ISO identifies one heavily impacted pricing node in the Pacific Gas and Electric (PG&E) load aggregation point (LAP) and one in the Southern California Edison (SCE) LAP, which correspond to an actual pricing nodes in the ISO system, for which only one resource is connected to each pricing node. Thus, the price nodes analyzed are different from month to month which may make an annual presentation of this data difficult to interpret.

- Appendix C: Exceptional Dispatch Bid Mitigation Analysis. In January 2009, the ISO applied the exceptional dispatch bid mitigation to the exceptional dispatches that are noncompetitive TMODELs and Delta Dispatch as of the month of August and began to provide the bid mitigation analysis in the January report.

2.2. Monthly Market Performance Report

The monthly Market Performance Reports[6] prepared by ISO Market Services and published on the ISO's website contain the three charts on exceptional dispatch described below. In the March 2010 Market Performance Report, data for February and March is shown.

1. Total Exceptional Dispatch Volume (MWh) by Market Type. Market types are Day-Ahead, Real Time Increments (Inc), and Real Time Decrements.

2. Total Exceptional Dispatch Volume (MWh) by Reason. Reasons are G-Procedure, Ramp Rate, SP26 Capacity, T-Procedure, Transmission Outage, and Other.

3. Total Exceptional Dispatch as Percent of Load. Monthly Average is also shown.

2.3. 120-Day Reports to FERC

The September 2 Order directed the ISO to file reports every 120 days that describe the status of the ISO's efforts to reduce the frequency of Exceptional Dispatch and the status of ISO's development of operational and product enhancements that would reduce reliance on Exceptional Dispatch. To date, the ISO has filed two 120-day reports on October 20, 2009[7] and on February 17, 2010[8] in Docket Nos. ER08-1178and EL08-88-. The next 120-day report is due on June 17, 2010.

[6] Monthly Market Performance Reports, http://www.caiso.com/2424/2424d03b3f610.html

[7] October 20, 2009 120-Day Report to FERC, http://www.caiso.com/244d/244ddae36eed0.pdf

[8] February 17, 2010 120-Day Report to FERC, http://www.caiso.com/2740/2740a2bb54660.pdf

3. Actions to Address Exceptional Dispatch

This section describes the actions that have been taken to date to reduce exceptional dispatch, as well as actions that are planned for future implementation. This is an update to the list of actions that appeared in the December 2, 2009 White Paper.

On April 9, 2010, the Exceptional Dispatch strike team was renamed as the Operator Intervention Team. Although exceptional dispatch issues are still a high priority objective, the team's broader focus allows it to address other operator intervention issues such as market transmission system limits adjustments.[9] Since the issuance of the December 2, 2009 White Paper, the team has been actively involved in most if not all of the actions described in this section.

3.1 Actions Taken To Date

Since March 31, 2009, the ISO has undertaken and implemented a number of actions to address and reduce exceptional dispatch. These actions are described in chronological order below.

- **Intermittent Deviation from Day-Ahead Schedules, April 2009** – Deviations from intermittent resources were causing control issues and flow model issues. The ISO modified software to account for the deviations and improve flows and imbalance.

- **Improved Load Forecasting and Load Distribution, May 2009** – Initially the ISO observed that very short-term load forecasting was not following changes in load direction well in the HASP timeframe versus the five minutes prior to Real-Time Dispatch. In order to address this observed forecast inconsistency, the ISO moved to basing its HASP and RTM forecast on an interpolation of the ISO Automated Load Forecast System 30-minute forecast. This adjustment in practice was implemented in mid-May 2009.

- **Improved Load Distribution Factor Scale to Regions, June 1, 2009** – Scaled load distribution factor per region has improved the accuracy in calculating the flow on paths between regions. This improvement mainly improved the accuracy of Real-Time flows on major north to south paths like Path 15 and Path 26 flows. This improvement had

[9] "ISO operators make adjustments for (1) conforming transmission limits to achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths, and (2) setting prudent operating margins consistent with good utility practice to ensure reliable operation under conditions of unpredictable and uncontrollable flow volatility. In conforming transmission limits the operators and operating engineers seek in part to compensate for the time lag, inherent in the structure of the five-minute real-time dispatch, between first detecting imminent congestion and the response of resources to dispatch instructions. In setting reliability margins, the operators seek to ensure that the market software produces a solution that is reliable and consistent with good utility practice within the general state of the system including potentially unpredictable flow variability and changing congestion patters. The term "biasing" has previously been used to refer to both these practices, but with this issue paper the ISO adopts the preferred term "conforming transmission limits" for the first category because it more accurately reflects the true intent and nature of this practice. The second category we will refer to simply as setting reliability margins." (Data Release & Accessibility, Issue Paper, 11/5/2009, p.13), http://www.caiso.com/245d/245d11208266d0.pdf

only a minor impact on exceptional dispatch. This enhancement was implemented on June 1, 2009.

- **<u>Improved LDF in RTM using Last State Estimator LDF, June 1, 2009</u>** – The ISO implemented an improved Load Distribution Factor (LDF) in RTM using the last State Estimator LDF. This action improved the accuracy of calculating flows. The use of more accurate real-time LDFs has resulted in improved real-time flow patterns. This improvement most likely reduced the need for the number of exceptional dispatches resulting from modeling differences in localized areas. This enhancement was implemented on June 1, 2009.

- **<u>Conformed Model Power Flows and Actual Power Flows, June 2009</u>** – An ability to conform modeled power flows and actual power flows through use of a flow bias provided the operator with the ability to correct for slight inaccuracies. This enhancement was implemented in early June 2009.

- **<u>Improved Start-Up Profiles, July 1, 2009</u>** - Prior to July 2009, ISO market software assumed that resources below their minimum operating level (Pmin) were effectively at zero MW until a resource reached its Pmin at the scheduled time. However, this enhancement revised this assumption by following actual telemetry up as the resource approached its Pmin prior to its scheduled start time. As a result, instead of assuming that a unit's operating level drops back to zero MW, the software will assume that the unit's last known operating level (as opposed to zero MW) is its current operating level, unless telemetry indicates otherwise. Under this new functionality, resources starting up now stay in the horizon calculation until Pmin is reached. This improvement contributes to a reduction in exceptional dispatches previously required to address this software limitation. This enhancement was implemented on July 1, 2009. Note that the Multi-Stage Generating (MSG) enhancements will make further improvements to the start-up profiles by estimating resource start-up progress, as opposed to assuming a last known operating level for a resource below Pmin.

- **<u>Operator Process Change For Greater Market Reliance, July 26, 2009</u>** – Previously, in the event that an operator had reason to believe a specific resource would be needed, and there were no optional resources, an operator would pre-commit the resource. On July 26, 2009, the process was modified to allow the market to commit the resource first. If the market committed the resource, then no exceptional dispatch was needed. However, if the resource was not committed by the market, the resource would be pre-committed by an operator and the market re-run.

- **<u>Added G-217 and G-219 Nomograms in RUC, July 26, 2009</u>** – As an interim solution to satisfy commitment constraints, the ISO implemented certain commitment requirements into RUC. On July 26, 2009 the ISO implemented two nomograms in RUC incorporating the constraints of two ISO Operating Procedures *G-217, South of Lugo Generation Requirements*, and *G-219 SCE Local Area Generation Requirement for Orange County*. These represented the bulk of the Day-Ahead exceptional dispatch unit commitment prior to July 26, 2009. The enforcement of these constraints in RUC resulted in a significant reduction in the "*Monthly average minimum-output energy from generation committed in day-ahead through exceptional dispatch*" as illustrated in Figure 1.13 from the 2009 Department of Market Monitoring (DMM) Annual Report, as shown in Section 4.8 of this white paper.

- On July 26, 2009, the ISO stopped issuing exceptional dispatch instructions to resources associated with the G-217 and G-219 operating procedures prior to the day-ahead market. As a result of this and allowing the IFM to run prior to pre-committing resources under exceptional dispatch, the frequency of day ahead exceptional dispatches has been significantly reduced without significantly increasing the amount of resources committed in RUC.

- Between July 1st and 26th, the frequency of exceptional dispatch unit commitments for G-217 and G-219 ranged between zero and 13 units per day, and averaged approximately six units per day. Beginning July 27, the volume of Exceptional Dispatch for G-217 and G-219 declined nearly to zero, as the units were mostly committed in either the IFM, or as needed in RUC, although there have been a few instances where there is still a need to manually commit post Day-Ahead.

- **Netted Larger Generation Resources, September 24, 2009** - Netted some of the larger generation resources where there is load behind the meter. The modification reduced some situations where transmission constraint limits had to be conformed to actual flow conditions, but may have addressed some specific cases were exceptional dispatch may have been used to avoid unnecessary dispatching a resource. This enhancement was implemented on September 24, 2009.

- **Implemented Variable Regulation, October 3, 2009** – The ISO implemented new functionality to vary its Regulation requirements in the IFM for different hours of the day. Previous practice was to procure only one amount of regulation up and down for all hours of the day. In contrast, the variable regulation functionality allows the ISO to procure different amounts of regulation for each hour. This new functionality more accurately calculates the ramp needed for load following and facilitates the procurement of regulation to meet the anticipated needs. This has resulted in greater amounts of regulation available to the ISO during periods when excessive ramps are experienced. While this effort was primarily aimed to address control performance, the collateral benefit has been a further reduction in exceptional dispatch that may have otherwise resulted to meet ramping requirements. Variable regulation functionality is described in more detail in the *Technical Bulletin on AS Procurement – Regulation*.[10] This enhancement was implemented on October 3, 2009.

- **Implemented Simplified Ramping, November 12, 2009** - Allows for more realistic accounting and sharing of ramping *capability* between changes in energy schedule and award of regulation and other operating reserves. Also under simplified ramping the operational ramp-rate will be used for all dispatches rather than using regulation ramp-rate when the resource is awarded regulation. It is not expected that simplified ramping will have a significant impact on exceptional dispatch. More detail on this approach is in the *Technical Bulletin on Simplified Ramping*.[11] This enhancement was implemented on November 12, 2009.

[10] *Technical Bulletin on AS Procurement – Regulation, 12/30/2009, http://www.caiso.com/2494/2494c16876b0.pdf*

[11] *Technical Bulletin on Simplified Ramping, 9/28/2009,http://www.caiso.com/2494/2494c16876b0.pdf*

- **<u>Added Transmission Constraints, November 2009</u>** – Periodically, the ISO adds or enforces transmission constraints (branch groups) where flow based methods can be modeled. The addition of new constraints generally occurs during model builds, which occur about every four to six weeks. However, in the event that a constraint is implemented between model builds, the ISO has committed to the issuance of a 10-day market notice, although constraints can be enforced with less notice as needed to maintain system reliability. The LA Basin import constraint (SCE_PCT_IMP_BG) limit based on observed conditions; see the Technical Bulletin for more information.[12]

- **<u>Minimum Online Commitment #1, G-217 and G-219 in IFM & RUC, February 4, 2010</u>** Using the Minimum Online Commitment (MOC) constraint capability, the ISO began enforcing operating procedures G-217 – South-of-Lugo Generation Requirements and G-219 – SCE Local Area Generation Requirements for Orange County. This enforcement was effective for trade day February 5, 2010 in the day-ahead market (DAM), including both the integrated forward market (IFM) and residual unit commitment (RUC). See the MOC Technical Bulletin for more information.[13] This has been referred to as MOC #1.

- **<u>Forbidden Operating Region (FO) in Real-Time Market, April 15, 2010</u>** – This action is focused on implementing the deferred functionality that would respect the documented forbidden region functionality in the RTM. This extensive enhancement will among others things allow the ISO to explicitly model transitional constraints from moving from one operational stage to another. By introducing this capability, the ISO will be able reduce use exceptional dispatch to ensure a resource once dispatched into Forbidden Operating Range will continue to be dispatched at a ramp rate consistent with the resources documented transit time in order to maintain its ramping capability in an operational range. Furthermore, the ability to model various inter-temporal constraints at the configuration level will allow a better modeling of those generation units and thus further reduce the need for exceptional dispatch. While the original forbidden operating region functionality for real-time was implemented on April the more detailed full Multi-Stage Generating Unit Modeling functionality is scheduled for implementation in fall 2010.[14]

- **<u>Minimum Online Commitment for Equipment Outages, April 26, 2010</u>** - The ISO expanded the use of the minimum online commitment (MOC) constraint for equipment outages in the ISO market effective for trade date April 26, 2010. This functionality was originally used for operating procedures G-217 South-of-Lugo Generation Requirements and G-219 SCE Local Area Generation Requirement for Orange County. Use of this functionality will be considered for equipment outages that have a commitment requirement to return the system to normal steady state limits following contingencies, or a commitment requirement to provide the necessary voltage and stability support. The appropriateness of using MOC for outages will depend on the following factors: duration

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12 Technical Bulletin: Import Limit Definition and Management in Support of Under-Frequency Load Shedding (UFLS), 12/3/2009, http://www.caiso.com/2479/247997c52e0f0.pdf

13 *Technical Bulletin on Minimum Online Commitment Constraint, 1/11/2010,* http://www.caiso.com/271d/271dedc860760.pdf

14 Market Notice on Real-Time Forbidden Operating Region Functionality Effective April 15, 2010, http://www.caiso.com/2777/2777a16c3a100.html

of the outage, complexity of the outage, time available to perform the necessary engineering analysis, and technical consideration of the resources capable of meeting the reliability need.

- **Minimum Online Commitment #2, G-206 in IFM & RUC, May 10, 2010** - The ISO has expanded the use of the minimum online commitment (MOC) effective May 10, 2010 to meet generation requirements as defined in operating procedure G-206 San Diego Area Generation Requirements in the day-ahead market (DAM), including both the integrated forward market (IFM) and residual unit commitment (RUC). In addition, the ISO has also started using MOC for select outages when appropriate. This functionality was originally used for operating procedures G-217 South-of-Lugo Generation Requirements and G-219 Southern California Edison (SCE) Local Area Generation Requirement for Orange County.

- **Improved Software and Model Improvements** - Since the start of the new market in April 2009, there have been substantial improvements in the software by resolving variances and model builds. This has had a corresponding result in reducing the number of exceptional dispatches associated with software limitations and disruptions. Variance resolutions occur on a regular basis about every one-to-two weeks. Model builds occur on a four-to-six week interval. The last model build DB47, promoted to production on April 22?, 2010 included enhanced modeling of LADWP area that is expected to improve market flows near the border of the ISO and LADWP balancing authority area as well as resource effectiveness. Such improvements are expected to reduce the need for operator intervention including exceptional dispatch. ISO DB48 Full Network Model implementation is scheduled for effective trade date June 17, 2010.[15]

3.2 Status of Current and Future Actions

Automated Load Forecast System Five-Minute – This action was focused on improving load forecast accuracy by directly forecasting for every five- and 15-minute time target in RTM using the Automated Load Forecast System. Currently, the ISO is interpolating and shaping the forecast between 30-minute forecast values produced by the Automated Load Forecast System. It is expected that a direct forecast of five and 15-minute values will lead to a more accurate forecast, account for changing conditions and better reflect peaks and valleys of the forecast. It is expected that this direct forecast will improve load forecasting and will further improve consistency of forecast occurring in HASP T-1.25 hours) time horizon with the Real-Time dispatch time horizon (T-5 minutes). In addition the direction five-minute forecast will allow for intra-hour peak conditions to be predicted. This improvement may help reduce the need for exceptional dispatch occurring after HASP to better align the intertie dispatch with changing load forecast conditions. The new ALFS will also improve the consistency between day-ahead and real-time load forecasts. Implementation date is to be determined.

Renewable Portfolio Standard Forecast – Beginning in September 2009, the ISO has increased its capability to stream more data from outside sources concerning solar and wind conditions to our forecast providers. This has enhanced our forecasting accuracy. In addition, on April 30, 2010, FERC issued an order conditionally accepting the ISO's filing of a tariff amendment to expand the scope of data required to be provided by wind and solar resources larger than 1 MW. The additional data requirements consist of (1) extending to additional

[15] ISO Market Notice for DB48, http://www.caiso.com/279d/279dabcf213d0.html

resources the obligation to install forecasting and telemetry equipment and to communicate relevant data to the ISO, and (2) reducing the threshold for reporting a forced outage of an eligible intermittent resource with total capacity of greater than 10 MW from the current outage capacity level of 10 MW to 1 MW. These requirements go into effect on July 1. More accurate forecasting and more information on outages should reduce the need for exceptional dispatch to manage wind and solar resources.

Better Modeling Shutdowns Profile – This action focuses on reducing the artificial ramp created by high Pmin units. Improving profile modeling will allow the ISO to better predict the imbalance energy impacts of resources shutting down that currently are assumed to shutdown instantaneously. The current instantaneous assumption results in a high burden on the ramping capability of a resource. The implementation date of this enhancement is to be determined.

Load Distribution Factor Forecasting - In some cases the short-term inaccuracy of load distribution factors can lead to situations where local constraints are not binding in the market but are in actuality or, the opposite, where they are binding in the market but not actually. In either case, exceptional dispatches at times are used to constrain specific resources on or off to satisfy a constraint that actually exists. Therefore improved load distribution factor accuracy in such cases could reduce the need for exceptional dispatch. This enhancement is expected to evolve over the next one-year timeframe. Currently, the Load Distribution Factor process used in the Day-Ahead Market incorporates a simple similar day process that does not account for changes in weather conditions. Therefore there are situations in which weather changes result in the similar day Load Distribution Factors not be sufficiently accurate. The first phase of this improvement is expected to be completed the by the end of 2nd quarter 2010. This phase will incorporate adjustment into Load Distribution Factor process that will account for weather changes that affect sub-LAP area load forecast.

Day-Ahead Market Commitment Process Enhancements to Reduce Cycling of Resources –To avoid unnecessary cycling of resources that can occur with a single-day commitment horizon the ISO is exploring a process enhancements to how initial conditions of a resource are determined. The ISO is taking two actions that related to mitigation of cycling of resources in the Day-Ahead Market: First the ISO is considering enhancements to the existing initial conditions process to allow for resources that intend to stay online to inform the ISO if this intent prior to the ISO starts the next day's Day Ahead market process. Second, the ISO has started to explore opportunity to phase-in a multi-day unit commitment process first utilizing the deferred functionality that was intended to provide for optimal decisions regarding Extremely Long Start resources possibly combined with an extension of the existing Residual Unit Commitment process to evaluate 48 to 72 hour instead of the current 24 hours. This approach would provide benefits of incorporating a bridged commitment decision across off-peak hours as well has sets up a more optimized input to initial conditions for the next day's Day-Ahead market input.

Transmission Upgrades that affect T-129 for Fresno Area - This project is comprised of line drop reconductoring of Panoche–Mendota and Panoche–Oro Loma 115-kV lines at the Panoche end. These transmission improvements are expected to reduce the window needed to rely on exceptional dispatch to satisfy T-129 procedure requirements. This project was recommended to the Pacific Gas and Electric Company to implement as soon as possible and was documented in the 2010 ISO Transmission Plan (short-term plan).

The limiting elements for both transmission lines mentioned above have been replaced by PG&E. The ISO is in the process of updating T-129 and the modeling of the transmission constraints in the ISO market to take advantage of expected higher thermal capacities of both transmission lines. The higher thermal capacities are expected to lead to reduced number of exceptional dispatches to meet the reliability requirements in procedure T-129.

Generation Upgrade at Humboldt – Presently, Humboldt generation units are being exceptionally dispatched in real-time until they are replaced by new generators in the fall of 2010. The Humboldt generators are dated and susceptible to increased risk of mechanical failure if subjected to frequent real-time market dispatches. Less frequent manual exceptional dispatches in real-time minimizes the number of dispatches Humboldt generator receive in real-time. Once the new Humboldt generators become operational, the ISO expects the real-time exceptional dispatches of Humboldt units will no longer be necessary.

Other Software Fixes - At times resources commitment status does not track with schedule or actual telemetry. Until these issues are fully addressed, exceptional dispatch is a mechanism to force the resource status to the correct status. Several of these issues have been addressed and the ISO will continue to address such observation.

Market Model Improvements - These model enhancements may include an expanded external model in areas to improve the actual flows and resource sensitivity to some constraints near the ISO border. This enhancement is expected to be implemented in the second quarter of 2010. On April 22, 2010, the ISO implemented enhancement by modeling additional portions of the external model in LADWP. These improvements are expected to improve the flow patterns on the VICTVL_BG as well provide for more reflective effectiveness of resources used to mitigate the flow on the VICTVL_BG which is expected to reduce the need to use exceptional dispatch of such resources.

New Market Products - The ISO committed to analyze data from July 2009 to March 2010 using the new product approach discussed with stakeholders during the December 6, 2009 stakeholder meeting. The results of the analysis are found in section 5. Based upon the analysis, the ISO concluded that the development of new products specifically designed to reduce the frequency of exceptional dispatch is not warranted.

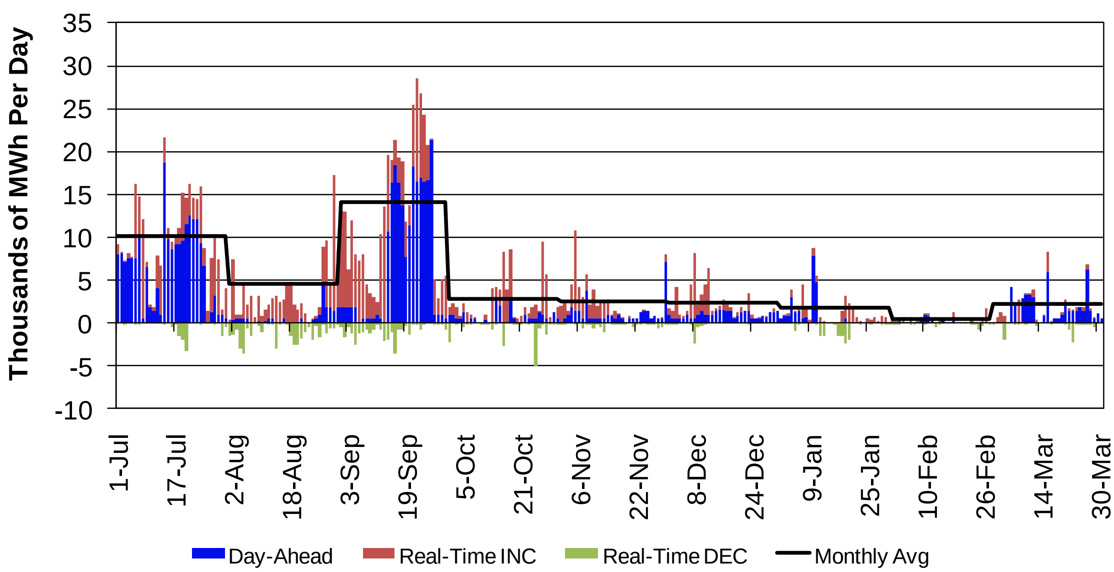
4. Trends of Exceptional Dispatch

Since March 31, 2009, the volume of exceptional dispatch has slowly declined as measured by almost any metric. The decline has not always been non-increasingly monotonic; however the general pattern is indisputable. This section provides some detail behind those trends. Appendix 1 provides additional graphs that have been produced in the past and have been updated to show data through March 31, 2010.

4.1. Volume by Market

Figure 1 below shows the exceptional dispatch volume for July 1, 2009 through March 31, 2010 classified into day-ahead and real-time markets. The Figure also shows the monthly average volume of exceptional dispatch. Except for the month of September 2009, the volume of exceptional dispatch has declined consistently from July 2009 through March 2010. Subsequently, in March there was a slight increase in the occurrence of exceptional dispatch. These reductions have been the result of actions taken by the ISO and detailed elsewhere in this paper.

Figure 1: Exceptional Dispatch Volume by Market Type

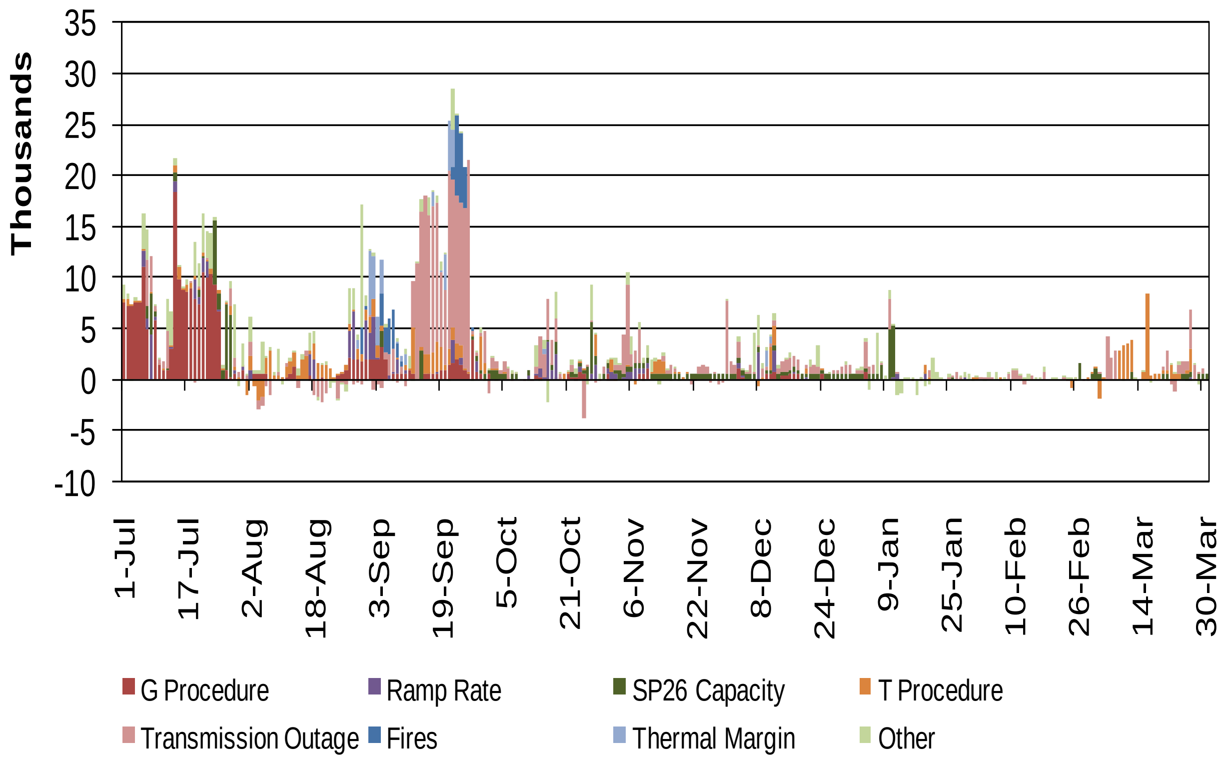


4.2. Volume by Reason

Figure 2 shows the volume of exceptional dispatch classified by reason for July 1, 2009 through March 31, 2010. All exceptional dispatches issued for generation procedures are shown as 'G procedure' and all exceptional dispatches issued for transmission procedure are shown as 'T-procedure'. The total volume of exceptional dispatch was mainly driven by local area requirements because of transmission outages (30 percent), local requirements due to 'G procedures' (24 percent), SP26 capacity requirements (10 percent) and requirements drive by 'T-procedures'.

The ISO implemented a software enhancement on July 27, 2009 which enabled the ISO to procure capacity in RUC market for 'G procedure' G-217 and 'G-219'. This resulted in significant reduction in exceptional dispatch volume for G-procedures in the subsequent months.

Figure 2: Exceptional Dispatch Volume by Reason



4.3. Frequency of Exceptional Dispatch MWh

The frequency of occurrence is another interesting metric, and there are essentially two measures of this, namely absolute frequency and relative frequency. Of these two measures the relative frequency provided here is the most interesting as it shows the relative proportion of exceptional dispatch MWh compared to non-Exceptional Dispatch MWh. In the set of three graphs below this frequency is measured against the cleared load in each market, and finally a summation graph measures it against total load across markets. Figure 3 shows the day-ahead exceptional dispatch frequency, which is simply the ratio of Exceptional Dispatch MWh to cleared MWh in the day-ahead market. This too shows the familiar downward trend, although not as pronounced as the volume figures shown earlier.

Figure 3: Day-Ahead Exceptional Dispatch Frequency

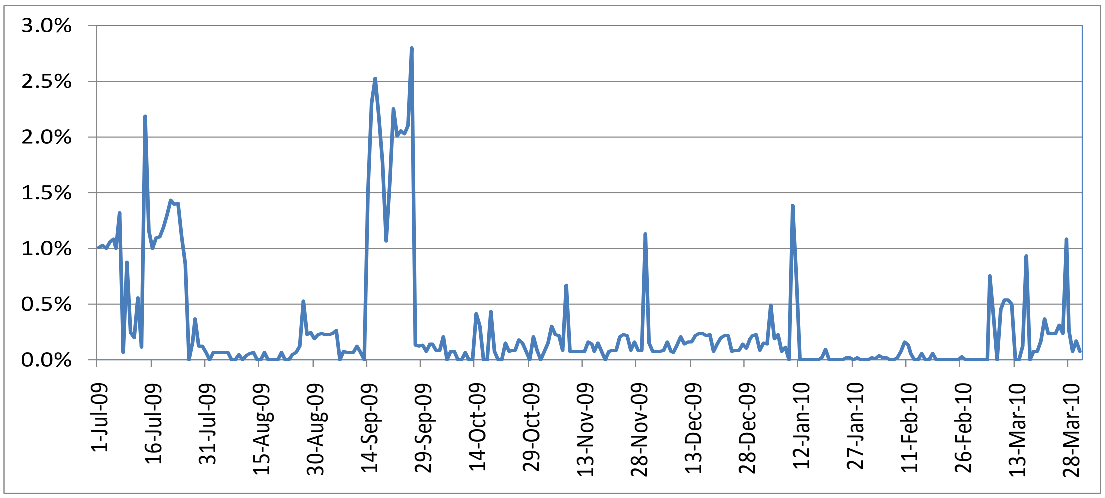
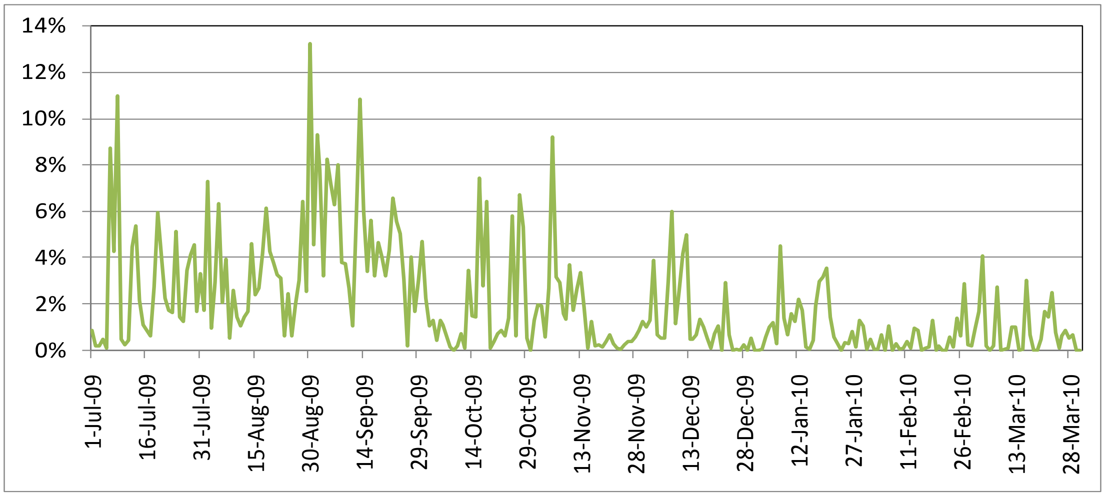


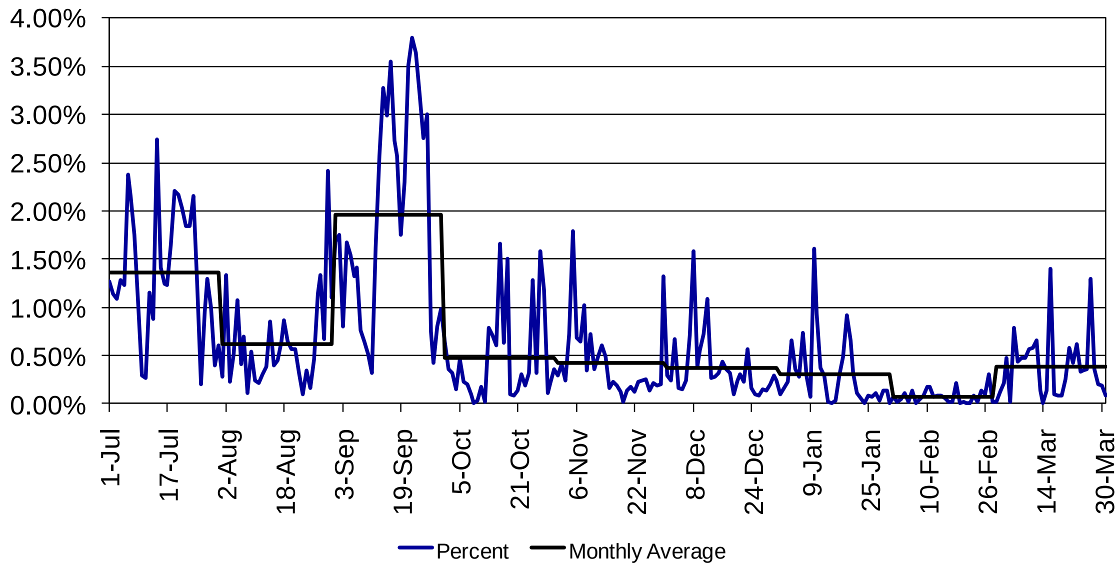
Figure 4 shows real-time exceptional dispatch frequency, which is the ratio of the absolute value of Exceptional Dispatch MWh to the absolute value of the cleared MWh in the real-time market. Both of these ratios have generally declined. More specifically, in Day-Ahead, Exceptional Dispatch declined as the ratio of Exceptional Dispatch MWh to Cleared MWh by 65% from a monthly average high of 0.38% in July-Dec 2009 to a much lower monthly average of 0.13% in Jan-Mar 2010. In Real-Time, the ratio of Exceptional Dispatch MWh to Cleared MWh declined by 69% from a monthly average high of 2.60% in July-Dec 2009 to a much lower monthly average of 0.80% in Jan-Mar 2010.

Figure 4: Real-Time Exceptional Dispatch Frequency



Perhaps a more apt metric for the frequency of Exceptional Dispatch is simply the total exceptional dispatch as a percentage of actual load. Figure 5 shows the volume of exceptional dispatch as percentage of actual load from July 1, 2009 through March 31, 2010 along with the monthly average. The monthly average volume of exceptional dispatch as percentage of actual load was the highest in September 2009 at 1.95 percent and lowest at 0.08 percent in February 2010.

Figure 5: Exceptional Dispatch Volume as Percent of Actual Load

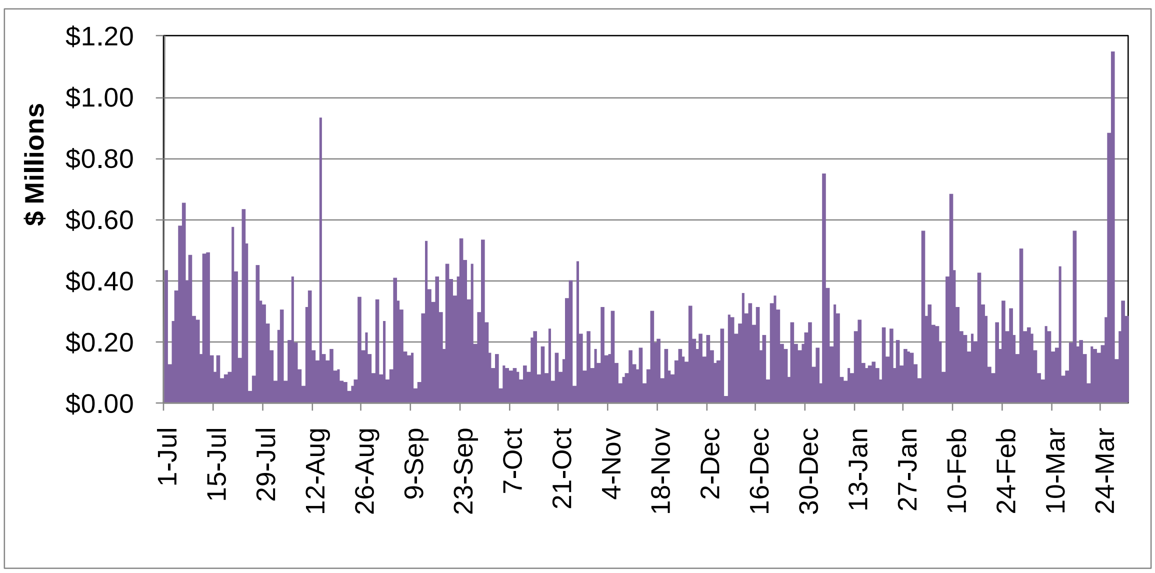


4.1. Costs of Exceptional Dispatch

The settlement of exceptional dispatches is not as straightforward as it was historically under the zonal system. Under the zonal system if a unit was committed it received a full payment for that commitment, and the cost of subsequent dispatches was easily calculated as (Bid Price - MCP). With the nodal system the principles remain the same, but the mechanics have become more complex.

In terms of commitment there is no longer an explicit full payment for commitment, instead there is Bid Cost Recovery (BCR) for all units that are committed by the ISO, but fail to make back their bid-in costs, with a few small exceptions, namely, exports and demand, for which there is a new settlement product. Thus, the units that are committed via exceptional dispatch may or may not receive compensation for this commitment depending on the monies earned by the unit on that trade date. This issue is complicated by the fact that there is no distinction in the settlements data between units that require BCR due to an exceptional dispatch and those that require BCR due to an ordinary market commitment. Consequently for this metric we simply produce the BCR costs, of which a portion are for exceptional dispatch (CC 6620[16]) and these costs are shown in Figure 6. All BCR costs are allocated out to measured demand.

Figure 6 Total BCR payments



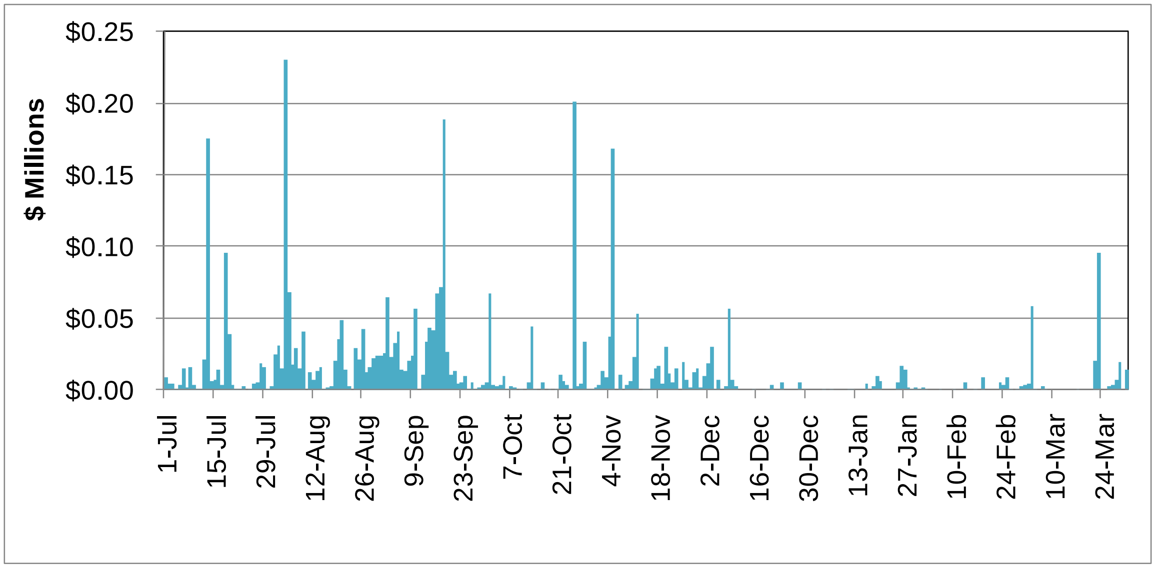
16 CAISO Settlements and Billing Configuration Guide, S&B BPM - CG CC 6620 Bid Cost Recovery Settlement, https://bpm.caiso.com/bpm/bpm/version/000000000000085.

In real-time there are incremental and decremental dispatches. The cost of exceptional dispatch is simply the excess monies paid to a generator above the LMP at the relevant Pnode. This is often termed the redispatch cost. The bulk of the Exceptional Dispatch cost is simply the regular LMP payment monies that are paid via CC 6470[17] to settle the exceptional dispatches to the LMP level. CC 6470 also settles emergency decremental dispatches.

The true cost of Exceptional Dispatch as shown in Figure 7, is the redispatch cost which is captured in CC 6488[18]. The redispatch costs paid through CC 6488 is for exceptional dispatch instructions used to mitigate or resolve congestion as a result of transmission-related modeling limitations in the FNM (Full Network Model). These costs are charged to the Participating Transmission Owner (PTO) in whose PTO service territory the Transmission-related modeling limitation is located.

If the modeling limitation affects more than one PTO, the Excess Cost Payments are allocated pro-rata in proportion to each PTO's Transmission Revenue Requirement (TRR).

Figure 7: Exceptional Dispatch Uplift Payment (CC 6488)

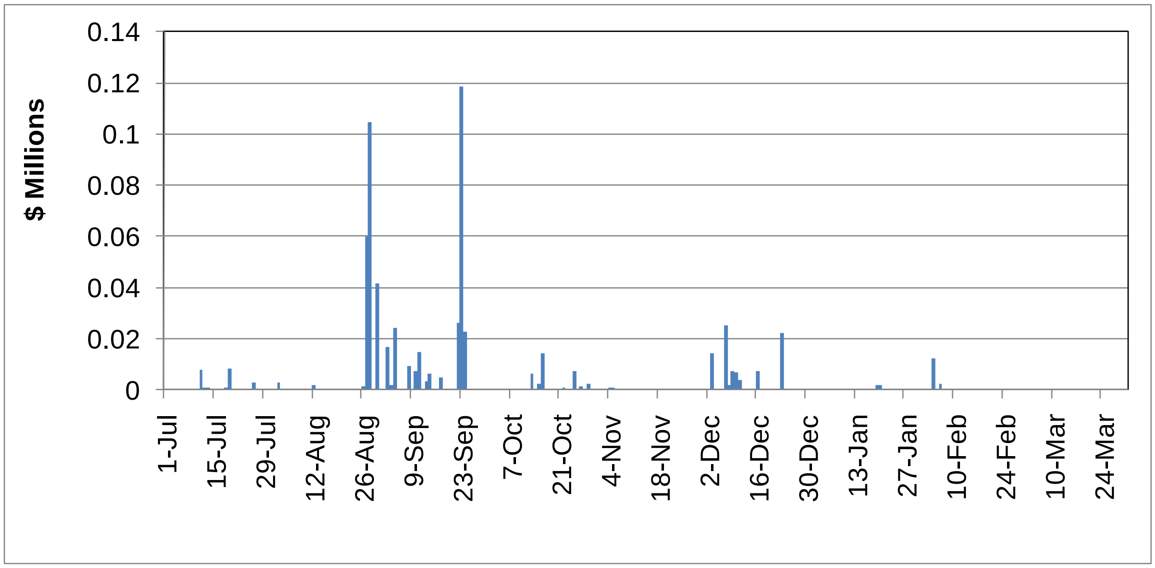


[17] ISO Settlements and Billing Configuration Guide, S&B BPM - CG CC 6470 Real Time Instructed Imbalance Energy, https://bpm.caiso.com/bpm/bpm/version/000000000000085 .

[18] ISO Settlements and Billing Configuration Guide, S&B BPM - CG CC 6488 Exceptional Dispatch Uplift Settlement, https://bpm.caiso.com/bpm/bpm/version/000000000000085.

There is another charge code, namely CC 6482[19] that is used to settle incremental emergency dispatches (such as support from or to a neighboring control area), however although these dispatches are individually important they are very infrequent and financially insignificant. Furthermore they are paid for by the relevant party needing the assistance, so there are no cost allocation nuances. For the sake of completeness they are shown in Figure 8 and Table 1.

Figure 8: Real-Time Excess Cost for Instructed Energy (CC 6482)



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[19] CAISO Settlements and Billing Configuration Guide, S&B BPM - CG CC 6482 Real Time Excess Cost for Instructed Energy,
https://bpm.caiso.com/bpm/bpm/version/000000000000085.

All of these significant costs are shown in Table 1, namely the BCR costs, a portion of which are due to Exceptional Dispatch, CCG6488, which is the redispatch cost, and CCG6482, which is the gross cost of emergency dispatches.

Table 1: Total BCR Payment, Uplift Payment (CC 6488) and Excess Cost (CC 6482)

Month	BCR	CC 6488	CC 6482
Jul-09	$9,675,168	$467,301	$21,177
Aug-09	$6,057,625	$831,831	$212,940
Sep-09	$9,227,655	$853,650	$255,853
Oct-09	$5,008,340	$410,425	$34,825
Nov-09	$4,911,103	$487,274	$1,676
Dec-09	$6,915,419	$146,674	$87,964
Jan-10	$5,669,266	$62,152	$3,372
Feb-10	$7,833,664	$34,617	$15,159
Mar-10	$8,439,144	$231,742	$0
Total	**$63,737,384**	**$3,525,668**	**$632,967**

5. Potential New Products Analysis

5.1. Analytical Approach for Potential New Products

The ISO utilized the approach for determining potential new products which was discussed with stakeholders on December 9, 2009. The ISO analyzed exceptional dispatch data from July, 2009 through March 31, 2010. Starting with 1,040 day ahead and 25,527 real time exceptional dispatch records, the data was consolidated by combining generation units to a single site and converting multiple hourly exceptional dispatches to a single daily event.

In order to focus on data which would support potential new products, the ISO excluded exceptional dispatches that were likely to be addressed by modeling and/or software improvements that the ISO either has implemented or is planning to implement in the future. In addition the ISO eliminated other reason codes which would not be addressed by developing new market products. Table 2 attached outlines by exceptional dispatch reason code if the data was included in the potential new product analysis.

Finally the remaining data was segmented between exceptional dispatches which lasted greater than four hours to classify as capacity related products and those with less than four hours as ancillary services related products. The results are summarized below.[20]

Table 2

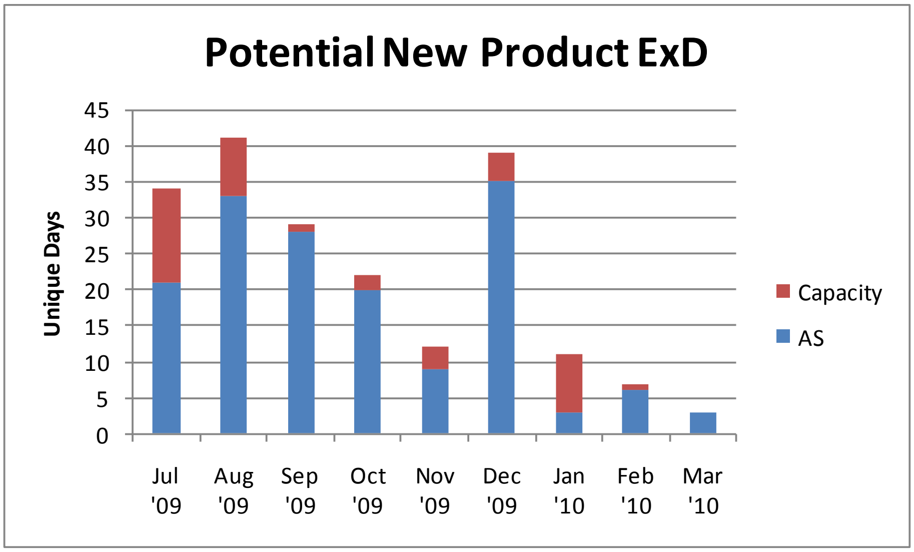
Consolidated Start				Potential Ancillary Services				Potential Capacity		
	DA	RT			DA	RT			DA	RT
Sites	17	249		Sites	0	70		Sites	3	4
Days	489	2208		Days	0	158		Days	9	31

The primary operational need being addressed by exceptional dispatch within the potential new product data set is system energy at the interties. System energy exceptional dispatches are post HASP adjustments to account for a significant and rapid change in conditions prior to the operating hour. The next driver is incremental on-line capacity necessary to account for post-contingency corrective measures which are not currently incorporated into Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED).

[20] RT = Real-Time, and DA = Day-Ahead.

Similar to overall exceptional dispatch trends, the potential new product data set has shown ongoing declines illustrated in Figure 9 below. The spike in December 2009 was driven by a large number of exceptional dispatches at the interties for system energy.

Figure 9



5.2. New Product Threshold Not Attained

Based upon the exceptional dispatch data above, the ISO does not believe a new product is warranted to reduce the number of exceptional dispatches. Given the potential new product data set trend is similar to overall exceptional dispatch trends, the ISO concludes that the modeling and software improvements taken to date have had a broader impact across all exceptional dispatch reason codes. In addition, the ISO believes that current and planned stakeholder initiatives will provide a secondary benefit of reducing exceptional dispatches. For example, the ongoing Dynamic Transfers initiative will increase the amount of dynamic scheduling over the interties allowing more flexibility in adjusting intertie schedules after HASP. Also, the Renewable Integration Market and Product Review initiative scheduled to begin in summer 2010 will outline operational needs resulting from increasing system variability and determine if new ancillary services products are required due to the increased penetration of intermittent resources.

For reference, Table 3 outlines Exceptional Dispatch reason codes and corresponding data.

Table 3 – Exceptional Dispatches Reason Codes for Product Analysis[21]

Included	Reason Code	Operational Need	Software Limitation	Model Limitation	Mitigation Measure Implemented	Mitigation Measure to be implemented
No	Circulation	Manual method to reflect DC circulation	No	No	None	None
No	G-206	Local Area Minimum Online Capacity	Yes	No	None – New Procedure under review	Minimum Online Capacity
No	G-217	Minimum Online Capacity for thermal and voltage contingency	Yes	No	RUC Nomogram	MOC for G-217 has been implemented
No	G-219	Minimum Online Capacity for thermal and voltage contingency	Yes	No	RUC Nomogram	MOC for G-219 has been implemented
No	G-233	Local Area Minimum Online Capacity	Yes	No	New Procedure under review	Trans Bay when it becomes commercial.
No	Generator Outage	Account for SLIC outage not being recognized due to minimum down time constraint	Yes	No	Address why SLIC outage not recognized	None
No	InterTie Emergency Assistance	External assistance to neighboring Balancing Authority	No	No	None	None
Yes	Load Forecast Uncertainty	Account for risk associated with potential load forecast error, Mainly summer due to large temperature sensitivity.	No	No	Portion is already accounted for in RUC Adjusted Forecast	Continue refine and improve weather and load forecasting
No	Market Disruption	HASP Failure or Timeout	Yes	No	Reduce HASP failures	Continue to reduce failure rate
No	Model Issue	Address flow differences or switching conditions that cannot modeled using existing version of model	No	Yes	Improve model in model build process	Improve model in model build process
Yes	Over Generation	Force de-commit or secure additional export	No	No	No	Consider lower bid floor
Yes	NP26 Capacity	To account to post-contingency corrective measure (How to return to normal limits)	No	No	None	Incorporate post-contingency corrective measures into SCUC/SCED

21 RT = Real-Time, and DA = Day-Ahead.

Included	Reason Code	Operational Need	Software Limitation	Model Limitation	Mitigation Measure Implemented	Mitigation Measure to be implemented
Yes	Path 26	To account to post-contingency corrective measure (How to return to normal limits)	No	No	None	Incorporate post-contingency corrective measures into SCUC/SCED
No	Ramp Rate	In order to position a resource in an operating range that ensures a ramping capability or though forbidden region to support awarded operating reserves	Yes	No	None	Forbidden Operating Region implemented. MSG will help but post-contingency issue may remain.
Yes	Region Reliability	To account to post-contingency corrective measure (How to return to normal limits)	No	No	None	Incorporate post-contingency corrective measures into SCUC/SCED
No	Reliability – Fire	Specific event to protect against unplanned and rapidly changing events due to fire	No	No	No	Allow DAM opportunity to commit resources first.
No	Software Limitation	Ensure resource is holding level or commitment despite software issue	Yes	No	Variance Fixes	Implement MSG
Yes	SP26 Capacity	To account to post-contingency corrective measure (How to return to normal limits)	No	No	None	Incorporate post-contingency corrective measures into SCUC/SCED
No	Spin Energy	Ensure energy dispatched from spin remained due software constraint	Yes	No	Address software issue	None
Yes	System Capacity	To address short-term reserve shortages until market can respond.	No	No	None	None
Yes	System Energy	Post HASP adjustment to account for significant and rapid change in conditions. Prevent imminent system emergency	No	No	None	None
No	T-103	SCIT- Intertie requirement	No	Yes	None	Explicitly model intertie constraint. Model external drivers
No	T-123	Bay Area	No	No	None	None
No	T-129	Fresno Area Load w/Remedial Action Scheme	No	Yes	None	Transmission upgrades. Incorporate RAS into contingency constraint

Included	Reason Code	Operational Need	Software Limitation	Model Limitation	Mitigation Measure Implemented	Mitigation Measure to be implemented
No	T-132	San Diego Area, complicated border loop-flow through external system	No	Yes	None	Model additional constraints. 25% min gen coming soon.
No	T-135	Lugo-Victorville (Path 61) and Sylmar (Path 41) Overload Mitigation, complicated by border loop-flow through external system	No	Yes	None	Some enhancements already implemented, improvement being evaluated.
No	T-138	Local energy, use limited resources	Local con-gestion	LDF	LDF improvements	MP education on Use Limited resource plans.
No	T-154	Drum Area Operations, complicated by water management constraints	No	Yes	None	None
No	T-165	Palermo – Rio Oso Area (RMR, water management)	No	No	None	None
No	T-167	Tesla/Bellota Summer Operations	No	No	None	None
No	T-170	Mirage-Tamarisk local Area with special load relief	No	No	None	None
No	Thermal Margin	Unloaded Capacity from Thermal Resources to account for forecast error and other unplanned events	No	No	RUC Demand Forecast confidence level	None
No	Transmission Outage PGAE	Specific outage condition	No	No	Intermittent deviation improvements	MOC for outages implemented.
No	Transmission Outage SCE	Specific outage condition	No	No	None	MOC for outages implemented.
No	Transmission Outage SDGE	Specific outage conditions	No	No	None	MOC for outages implemented.
No	Transmission Outage (Other)	Specific outage conditions	No	No	None	MOC for outages implemented.
No	Unit Test – DR	Specific testing	No	No	None	None
No	Unit Testing	Resource Test	No	No	None	None

6. Next Steps

As stated in the May 18, 2010 Market Notice, the ISO will hold a stakeholder meeting on June 17, 2010 to discuss the issues presented in this White Paper. Stakeholders may submit written comments on the White Paper to WMcCartney@caiso.com by close of business July 1, 2010.

Stakeholders are to use the Comments Template that will be posted to the ISO website after the meeting on or before June 21, 2010.

The ISO will submit its next 120-day Report to FERC on Exceptional Dispatch issues on June 17, 2010. The next 120-day Report after June 17, 2010 is due on October 15, 2010.

Appendix 1: Additional Trends of Exceptional Dispatch - Graphs Reproduced For Continuity

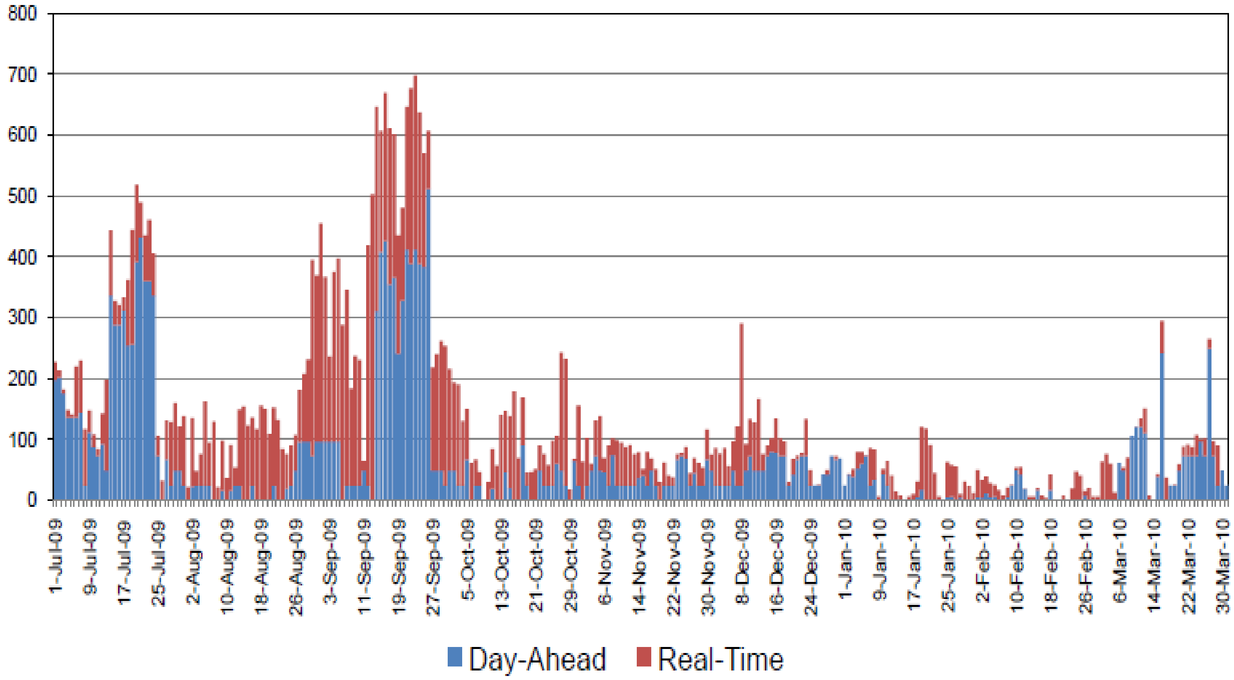
There are a number of different metrics that one might conceivably produce to capture the nature of exceptional dispatch. The principal measures are those that are produced within the body of the white paper, namely MWh volume (by market or by reason), frequency, i.e. what proportion of energy dispatched is exceptionally dispatched, and cost. Volume, frequency and cost represent the main representations of exceptional dispatch that are interesting. There are lesser measures that can also aid understanding, such as the volume of minimum load energy constrained on by exceptional dispatch as sometimes there are concerns that such energy spilling onto the grid might depress prices. It is worth noting in this context that all exceptional dispatches, except some emergency dispatches, occur through the software system precisely so that it can continue to optimize dispatch around the exceptional dispatches.

Historically the ISO has also produced the graphs that are presented below. These graphs are based on entries garnered from the SLIC logs. These graphs are not as simple as the main graphs as the SLIC log entries (or dispatches) are not a uniform class. Counting dispatches comingles commitment dispatches with energy dispatches, and further comingles large MW dispatches with small MW dispatches. Dispatches are a broad category and the quality of the information conveyed is degraded by the mixing of different classes of products, and the graphs are more prone to misinterpretation. Further in constructing the metrics there is more interpretation by the analyst, for example, is a 10-hour dispatch equivalent to 10 one-hour dispatches? How does one account for partial hours? For this reason the ISO will no longer produce these graphs presented below as its monitoring has progressed to more sophisticated and accurate measures of exceptional dispatch. For the sake of continuity the ISO reproduces them here one last time.

Hours of Exceptional Dispatch by Market Type and Resource

The total hours of exceptional dispatches are calculated as sum of hours for each resource that was issued an exceptional dispatch. From July 2009 through March 2010, the ISO issued exceptional dispatches that total of 37,427 hours, as shown in Figure 1 below. Of the total, 48 percent (17,859 hours) were in the Day-Ahead Market, whereas 52 percent (19,568 hours) were in the Real-Time Market.

Figure 1: Hours of Exceptional Dispatch by Market Type



As shown in Table 1 below, although Exceptional Dispatch hours have declined in absolute terms, the percentage of Exceptional Dispatch hours in the DA and RT markets has varied from month to month.

Table 1

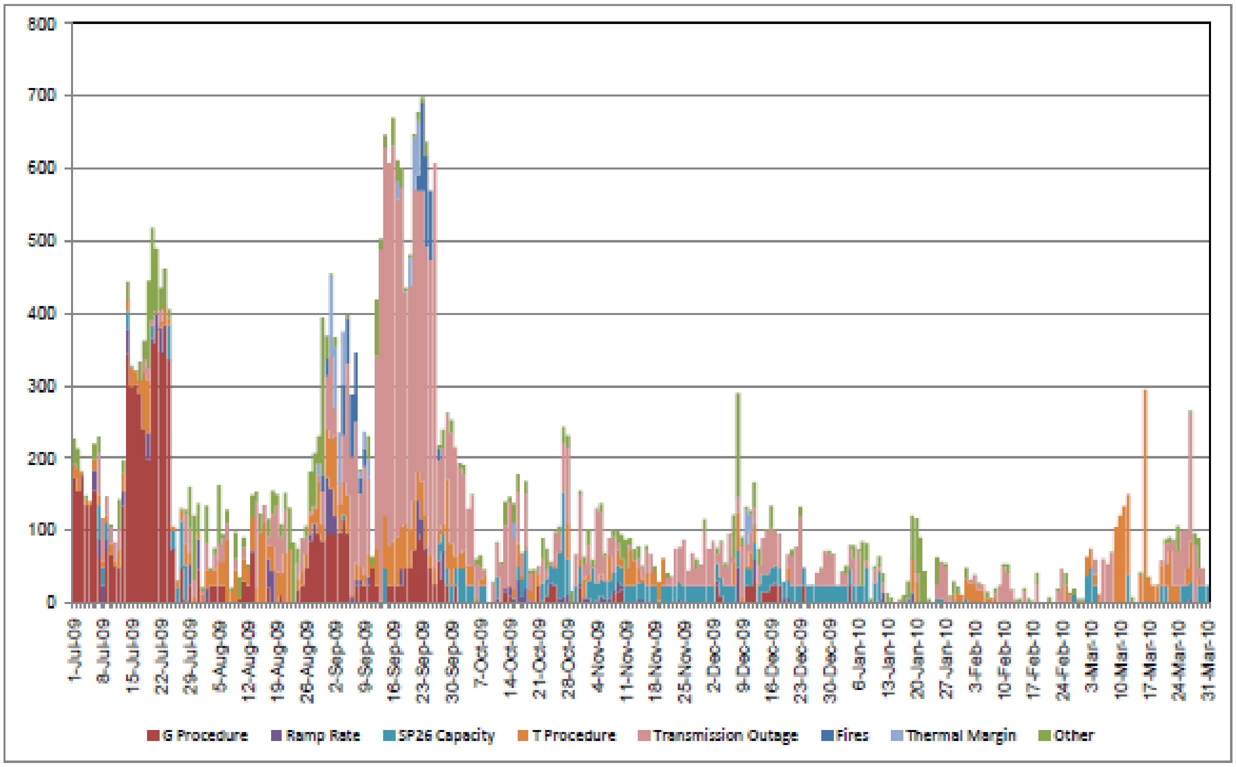
Hours of Exceptional Dispatch by DA & RT (%)

Hours of Exceptional Dispatch by Market (%)									
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10
DA	73%	19%	44%	24%	48%	55%	33%	34%	73%
RT	27%	81%	56%	76%	52%	45%	67%	66%	27%

Hours of Exceptional Dispatch by Reason and Resource

As previously noted, the total number of hours associated with Exceptional Dispatch declined significantly as noted in Figure 2. Exceptional Dispatch hours in the DA and RT markets declined by 73% from a monthly average high of about 5,491 hours in July-Dec 2009 to a much lower monthly average of 1,494 hours in Jan-Mar 2010.

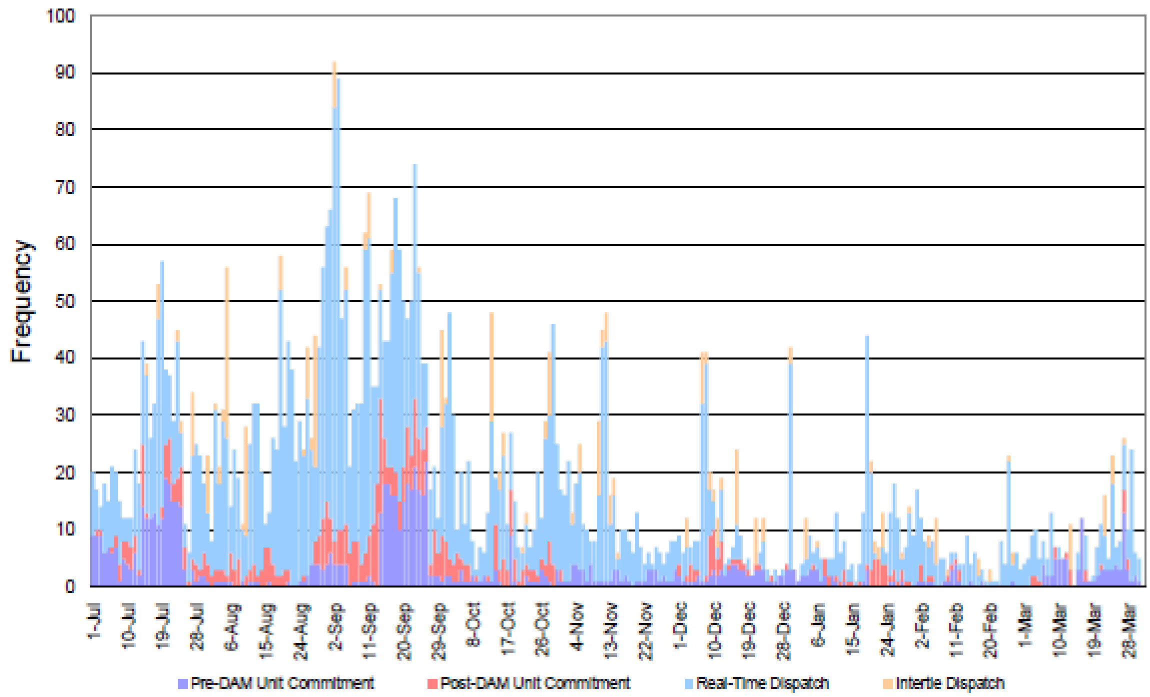
Figure 2: Total Hours of Exceptional Dispatch by Reason



Frequency of Occurrence by Market Type

The frequency of occurrence of Exceptional Dispatch has declined significantly. Exceptional Dispatch declined in Frequency by 67% from a monthly average high of 756 exceptional dispatches in July-Dec 2009 to a much lower monthly average of 249 exceptional dispatches in Jan-Mar 2010. See Figure 3.

Figure 3: Exceptional Dispatch Frequency by Market Type



The frequency of exceptional dispatch by dispatch type is shown in Table 2 below. Although there is some variation in exceptional dispatch frequency, overall exceptional dispatch frequency has continued to decline.

Table 2

Exceptional Dispatch Frequency by Dispatch Type

Exceptional Dispatch Frequency By Dispatch Type				
	Pre-DAM	Post-DAM	Real-Time	Intertie
Jul-09	31%	11%	54%	4%
Aug-09	4%	10%	76%	10%
Sep-09	18%	15%	64%	3%
Oct-09	8%	13%	72%	7%
Nov-09	14%	0%	76%	9%
Dec-09	19%	12%	53%	16%
Jan-10	10%	15%	68%	8%
Feb-10	10%	5%	74%	10%
Mar-10	32%	7%	53%	8%

Energy Volumes from Day-Ahead Unit Commitments

Energy volumes associated with Day-Ahead Unit Commitments from Exceptional Dispatch have significantly declined. Energy volumes associated with Day-Ahead Unit Commitments from Exceptional Dispatch have declined by over 80% from a monthly average high of 319 MW during July-Dec 2009 to a much lower monthly average of 57 MW in Jan-Mar 2010.

Figure 1.13, copied below for this Exceptional Dispatch White Paper, originally appeared in the Department of Market Monitoring's 2010 Quarterly Report. It is copied below for reference.

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