# Exceptional Dispatch White Paper

December 2, 2009

# ***Table of Contents***

# 1 Introduction

Reliability requirements that cannot be resolved through the California ISO ("ISO") market software are met by manually issued exceptional dispatches. The ISO is committed to reducing reliance on exceptional dispatch to the extent possible. The ISO has initiated a stakeholder process to assess the reasons underlying exceptional dispatch and address what appropriate modeling or software solutions and/or market products may be developed to reduce the need for exceptional dispatch going forward that will reduce reliance on exceptional dispatch to situations that are rare and infrequent such as actual or imminent emergencies.

This paper has been prepared to facilitate discussion with stakeholders at a stakeholder meeting on December 9, 2009. It provides a discussion of the uses of exceptional dispatch, actions to address exceptional dispatch, trends of exceptional dispatch, reasons for exceptional dispatch, and costs and market impacts of exceptional dispatch. Additional information on this stakeholder process and the development of exceptional dispatch is available at http://www.caiso.com/1c89/1c89d76950e00.html. Exceptional dispatch reports are available at http://www.caiso.com/241d/241dca223c760.html.

## 2 Background

"Exceptional dispatch" is a term used to describe a commitment or dispatch performed manually by an ISO operator in cases where unit commitments and/or energy dispatches made by the market software did not fully address a particular reliability need, i.e., is not a result of the market optimization in the Integrated Forward Market ("IFM"), Residual Unit Commitment market ("RUC") or Real-Time Market ("RTM"). An exceptional dispatch can be issued to address issues related to generation or transmission facilities, and can be used to address local or system needs. To the extent possible the ISO utilizes solutions selected by the market applications before issuing exceptional dispatches.

Exceptional dispatch is a necessary feature of ISO operations, as exceptional dispatches address operating constraints that cannot be fully enforced within the automated economically dispatched market and thus require operator intervention.

Exceptional dispatches are issued for a variety of reasons, including the resolution of constraints that are not properly modeled in the software, software execution errors, and other reasons, as discussed in this issue paper. Exceptional dispatches can be in the form of unit commitments, usually issued in the day-ahead, or for real-time exceptional dispatch energy, in which a resource that is already available to the market is constrained to be above or below a certain level of output. Decisions regarding exceptional dispatch are based on physical requirements specified in established operating procedures, power flow analysis of transmission outages, or to work around the result of market application failure.

Grid operators have limited discretion in issuing exceptional dispatches, subject to authority of the ISO Tariff Section 34.9 and in accordance with ISO Operating Procedure M-402 (Exceptional Dispatch), M-401 (Day-Ahead Market Operations), and M-403 (Real-Time Market Operations).[1] This authority and settlement details are summarized in an ISO *Technical Bulletin* issued May 5, 2009.[2] Operators also have at their disposal a tool that assists them in selecting resource(s) for exceptional dispatch that are under Resource Adequacy obligation whenever effective.

In the first few months following the start of the market, the use of exceptional dispatch has been higher than some expected and this has raised concerns, particularly among generating unit owners, about the efficacy of the new market and impact these manual dispatches are having on market prices.

### 2.1 ISO Authority under Tariff Section 34.9

Pursuant to the ISO Tariff Section 34.9, exceptional dispatches to start up, shut down, increment or decrement a resource may only be issued for the following reasons:

1. During a System Emergency
2. Prevent an imminent System Emergency
3. Prevent a situation that threatens System Reliability that cannot be addressed by the RTM optimization and system modeling

---

[1] CAISO Market Operating Procedures, http://www.caiso.com/thegrid/operations/opsdoc/marketops/index.html.

[2] CAISO Technical Bulletin on Exceptional Dispatch, http://www.caiso.com/23ab/23abf0ae703d0ex.html. The ISO intends to publish and updated version of this Technical Bulletin in the near future.

4. Perform Ancillary Service Testing
5. Perform pre-commercial operations testing for generating units
6. Perform PMax Testing
7. Mitigate for over-generation
8. Provide for Black Start
9. Provide for Voltage Support
10. Accommodate Transmission Ownership Rights or Existing Transmission Contracts Self-Schedule changes after Market Close of the Hour Ahead Scheduling Procedure
11. Reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC
12. In the event of a Market Disruption, to prevent a Market Disruption, or to minimize the extent of a Market Disruption
13. Reverse the operating mode of a Pumped-Storage Hydro Unit
14. Any Full Network Model modeling limitations that arise from transmission maintenance, lack of voltage support at proper levels as well as incomplete or incorrect information about the transmission network, for which Participating Transmission Owners have the primary responsibility
15. In response to system conditions including threatened or imminent reliability conditions for which the timing of the RTM optimization and system modeling are either too slow or incapable of bringing the ISO Controlled Grid back to reliable operations in an appropriate time-frame.

## 2.2 Day-Ahead Exceptional Dispatch Commitment Instructions

On a day-ahead basis, the ISO may issue exceptional dispatches to commit non-short start and non Extremely Long Start units at their minimum operating level for the next operating day if an un-modeled constraint is forecast to be binding. These day-ahead commitments may be made either before or after the day-ahead IFM and RUC processes are completed.

Day-ahead exceptional dispatch commitments typically are issued for reliability requirements such as voltage or online capacity requirements that are not reflected in the market applications. An ISO grid operator issues an exceptional dispatch day-ahead commitment to bring a relatively long-start generator online to operate at its minimum generation capacity (or “minimum load”) so that the unit will be available for dispatch when needed.[3] According to Operating Procedure M-402, exceptional dispatch day-ahead commitments are generally issued after the day-ahead market is completed. If specific resources that grid operators and transmission engineers deem necessary for reliability were not committed in the market, operators will commit them with an exceptional dispatch startup instruction. In this case, ISO operators will issue an exceptional dispatch commitment at minimum load in the Hour-Ahead Scheduling Process (“HASP”). In real-time, ISO operators may issue exceptional dispatch energy dispatches above PMin or the

[3] Exceptional dispatch of longer start units should not be confused with the bid-based Extremely Long Start commitment process.

IFM schedule (alternatively if the ISO needs the resource to decrease its output, the ISO may issue an exceptional dispatch below an IFM schedule). However, if a particular resource "is the only unit that can meet the reliability requirement and there is a reasonable basis for believing or has established by running an initial pass of the market that the unit will not receive a Day-Ahead Schedule", the grid operator may commit the resource prior to running the day-ahead market.[4] In this case, the exceptional dispatch commitment appears as a self-schedule at minimum load in the day-ahead IFM market, so that the energy that the exceptionally dispatched resource generates will be accounted for in the optimization. This avoids the over-commitment that would occur if that capacity were to be committed again by the IFM/RUC, and results in more accurate system dispatch and price signals.[5]

## 2.3 Post Day-Ahead Exceptional Dispatch Instructions

Following the Day-Ahead Market, the grid operator reviews the resource commitments to assure that the minimum online capacity established in specific operating procedures for given operating conditions has been met by Day Ahead Market awards. If a resource requirement remains unsatisfied, the grid operator will exceptionally dispatch resources to meet that requirement. The minimum capacity requirement established in the procedure is based on offline studies that ensures that sufficient resource capacity is online to meet thermal and voltage requirements in case of critical contingencies. While the market software is able to model thermal constraints due to transmission contingencies, the market software is not currently able to mitigate for contingencies that result in loss of supply or have a "Special Protection Scheme"[6] associated with the contingency or is limited by voltage constraints.

## 2.4 Real-Time Exceptional Dispatch Energy Instructions

In the RTM, the ISO also issues exceptional dispatches for additional energy (above minimum load), a change in output (incremental or decremental, including to shutdown), or to hold resources off line that otherwise would have started. These real-time exceptional dispatches for energy can be issued to units that have been committed on a day-ahead basis through exceptional dispatch, as well as units that are committed through self-schedules or the day-ahead market process.

An ISO grid operator issues an exceptional dispatch energy instruction to constrain a resource within a particular range of output. For example, a resource that receives a day-ahead exceptional dispatch commitment may have a very slow ramp rate or a forbidden region of operation at its minimum load level. The grid operator may issue an exceptional dispatch energy instruction to raise the resource to a minimum level at which it can be responsive to market instructions. Exceptional dispatch energy instructions are also used to keep multi-stage combined-cycle units in particular generation configurations; that is, with a particular combination of turbines and heat-recovery steam generators on. The specific configuration is not currently modeled by the market software, and an instruction that would require the startup or shutdown of a turbine can be costly if it remains in that configuration for a short time. The ISO is in the process of implementing Multi-Stage Generating Unit Modeling (see http://www.caiso.com/2078/2078908392d0.html).

---

[4] See Operating Procedure M-402 at page 5.

[5] The term "self-schedule" use in this paragraph is an exceptional dispatch and thus an ISO commitment eligible for bid cost recovery.

[6] A "Special Protection Scheme" ("SPS") is an automated protection scheme that either runs back generation, or drops load in case of a specific contingency.

Operators also use exceptional dispatch to “bridge” resources across times when market awards would otherwise have them shutdown, but forecast conditions would require that resource (or a similar resource) to be available for the following day. Because the resource may be subject to minimum down time, precluding that resource from returning, operators may exceptionally dispatch the unit at minimum load to ensure unit availability for the next day.

The exceptional dispatch energy instruction is passed to the market software as a minimum or maximum output constraint. That is, the software would interpret the exceptional dispatch energy minimum or maximum constraint megawatt output level respectively as the resource’s effective minimum or maximum load. There is also a “fixed” constraint option, which holds a resource fixed at a specific level of output.

Grid operators may also commit short-start units as real-time exceptional dispatch energy instructions. These are typically fast-start resources that do not require Day-Ahead commitment, and are used, for example, to work around isolated situations in the presence of transmission outages or when impending Forced Transmission outages are known ahead of time that were not part of Day-Ahead Market.

## 2.5 Exceptional Dispatch Bid Mitigation

For the first four months of the new market design, all energy bids for exceptional dispatch eligible for “pay as bid” compensation are subject to exceptional dispatch bid mitigation except for resources without capacity contracts that have elected supplemental revenues.[7] Units committed by exceptional dispatch are eligible for start-up and minimum load costs as part of bid cost recovery. Since August 1, 2009, the only exceptional dispatches that are subject to bid mitigation are those that:

- Resolve transmission-related modeling limitations involving non-competitive paths as determined by Department of Market Monitoring’s Competitive Path Assessment; or
- Are in support of the Delta Dispatch requirement.

The ISO tool that was developed to assist operators with these requirements was recently enhanced to include the capability of determining whether a particular path requiring an exceptional dispatch is competitive.

## 2.6 Logging and Measurement Issues

The original exceptional dispatches tools developed by the ISO focused on real-time energy exceptional dispatches. As of April 1, 2009, the ISO had a semi-automated tool in place for logging real-time exceptional dispatch dispatches. Although the ISO had tariff authority to issue exceptional dispatches at any time, the ISO did not have a similar tool, though all exceptional dispatches are logged as noted below. Therefore, early day ahead exceptional dispatch commitments are less clearly distinguishable in data from exceptional dispatch energy instructions. The ISO has made changes to improve these processes, but the process is still largely manual.

As described in Operating Procedure M-402, operators use the ISO’s Scheduling and Logging software tool (“SLIC”), to record exceptional dispatches, and they also enter instructions in the market software. The SLIC exceptional dispatch template provides for manual entry of an

[7] The exceptional dispatch bid mitigation for the April 1-July 31, 2009 period will be reflected as an adjustment on a future invoice.

extensive set of information regarding the instruction. Due to the dynamic use of the exceptional dispatch process and manual nature of the SLIC entries, data fields may be left blank or miscoded. Exceptional dispatch entries are reviewed in a post-market process and corrected as appropriate.

For this report, the data is principally SLIC information supplemented with data from the Market Quality System ("MQS"). It is the most accurate currently available and it is worth noting that this data has been through the T+38B initial statement process wherein many unresolved issues are fixed.

# 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 to be implemented in the future.

## 3.1 Actions taken to Date

To date, the ISO has undertaken and implemented a number of actions to address and reduce exceptional dispatch.

1. Established a Strike Team – On July 27, 2009 the ISO formed an exceptional dispatch "strike team" to focus on potential improvement to practices and software to reduce exceptional dispatches, particularly with respect to unit commitments made in the day-ahead timeframe. This strike team also focused on improving the consistency and logging of exceptional dispatch data, and providing more accurate and timely feedback on exceptional dispatch trends to operations staff. The team also monitored the impacts of new RUC capacity nomograms for G-217 and G-219 designed to meet reliability requirements previously met by committing additional units via exceptional dispatch either before or after the IFM. The result of these efforts, combined with the new RUC capacity nomograms discussed below, appears to have reduced exceptional dispatches in late July and August. However, as is discussed in subsequent sections of this paper, the amount of capacity committed via exceptional dispatch increased again in late August and September due to other factors, such as the need to protect against potential and forced transmission outages due to fires in Southern California and a significant prolonged forced major transmission line outage.

2. Improved Startup Profiles - Initially, during start-up while a resource was below its minimum operating level the software was expecting the resource to remain at zero and then go to its minimum operating level at the scheduled time. The ISO implemented an enhancement that revised the assumption to following the actual telemetry up as the resource approached its minimum operating level prior to its scheduled start time. Units starting up now stay in the horizon calculation until the unit is at PMin. This improvement reduced exceptional dispatches previously required to address this software limitation. This enhancement was implemented on July 1, 2009

3. Implemented Variable Regulation - Rather than procuring only one amount of regulation up and down for all hours of the day, variable regulation allows the ISO to procure different amounts for each hour. The revised process more accurately calculates the ramp needed for load following and enables procuring the 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 to address control performance, a collateral benefit has been to further reduce the exceptional dispatches that may have otherwise resulted to meet ramping requirements. This enhancement was implemented on October 3, 2009.

4. Added Nomograms in RUC – As an interim solution to satisfy capacity constraints, the ISO has implemented certain capacity requirements into RUC. The ultimate goal is to implement capacity requirements into the IFM, but that approach is complicated and requires a significant amount of work to implement. To provide immediate action, 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.

These procedures correlate the magnitude of area load and the amount of online generating capacity needed in the respective areas. ISO Operations created a nomogram to maintain the appropriate relationship between available local generation and capacity requirements. These nomogram compare *area load* to the *generation capacity* needed to withstand the next contingency (i.e., loss of transmission capacity into the local area), as required by reliability criteria. Because the nomogram identifies a capacity requirement, implementation within only RUC was selected as a starting point to enforce the nomogram rather than the IFM, which determines energy requirements.

This approach does allow for the normal running of the IFM first. The IFM run provides the market the opportunity to commit resources that may satisfy the nomogram requirements. RUC then commits any additional capacity requirements still required to satisfy the reliability requirements.

On July 26, 2009, the ISO stopped issuing exceptional dispatch instruction to resources associated with the G-217 and G-219 operating procedure 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 capacity committed in RUC.

Between July 1 and 26, 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 ED for G-217 and G-219 declined nearly to zero, as they are now mostly committed in either the IFM, or as needed in RUC (there have been a few instances where there is still a need to manually commit post Day-Ahead).

5. Implemented Simplified Ramping - 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. This enhancement was implemented on November 12, 2009.

6. Improved Load Distribution Factor Scale to Regions - 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 only a minor impact on exceptional dispatch. This enhancement was implemented on June 1, 2009.

7. Improved Load Distribution Factor in RTM using Last State Estimator Load Distribution Factor – This action improved the accuracy of calculating flows. Movement to more accurate Real-Time load distribution factors improved Real-Time flow patterns which in some cases in local areas reduced the amount of exceptional dispatch necessary to compensate for localized modeling differences. This improvement may have an effect on reducing the need for exceptional dispatch resulting from modeling differences in localized areas. This enhancement was implemented on June 1, 2009.

8. Conformed Modeled Power Flows and Actual Power Flows – 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.

9. Changed Process to provide Greater Reliance on Market – If the operator has reason to believe that a specific resource is going to be needed and there are not optional resources, the

operator would pre-commit the resource. On July 26, 2009, the process was modified to allow the market to first to determine if the resource that was expected to be needed was committed via the market. If the resource was committed, then no exceptional dispatch was necessary. However, if the resource was not committed, the resource would be pre-committed and the market re-run.

10. Improved Load Forecasting and Load Distribution – 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 basing its HASP and RTM forecast based on an interpolation the ISO Automated Load Forecast System 30-minute forecast. This adjustment in practice was implemented in mid-May 2009.

11. Netted Larger Generation Resources - 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.

12. Improved Software - 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 network model build occurred on November 3, 2009.

13. Added Transmission Constraints - Added additional or enforced additional transmission constraints (branch groups) where the ISO can model them using flow based methods. These generally occur either during a model build, but constraint constraints be enforced as needed when system conditions warrant. A recent example of is the additional constraint enforcement of SCE_PCT_IMP_BG limit base on observed conditions.

14. Accounted for Imbalance caused by Intermittent Deviation from Day-Ahead Schedules – In 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.

## 3.2 Actions to be implemented in Future

1. Minimum Online Capacity Constraint - As discussed above under item 4, RUC Nomograms, the ISO has 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*. The ISO views the use of RUC to satisfy capacity constraints as an interim solution. The ultimate goal is to implement capacity requirements into the IFM. Doing so will further enable generation owners that are committed for these purposes to also sell energy and ancillary services in the IFM market. The ISO is working internally as well as with the market software vendor to develop and implement an IFM capacity solution. The ISO is working to constrain to model the minimum on-line capacity so current nomogram constraints G-217 and G-219 in RUC can be converted to minimum on-line capacity and be enforced in any pass of the market including IFM or RTM. It is estimated that this constraint will be available by the end of the 2009.

The minimum on-line capacity constraint is a constraint that ensures the sum of effective online capability as measured a resources maximum normal capability (i.e., PMax) of a defined group of resources is above a minimum level. It should be noted that the actual capability under this constraint can either be loaded for energy or unloaded. The minimum online constraint formulation is provided below.

$$\sum_{i \in G} a_i \, Y_{i,t} \, P_{i,t}^{\max} \geq P_{G,t}^{moc} \qquad \forall t, G \qquad (1)$$

Where:

$P_{G,t}^{moc}$ Is the minimum total online capacity required for interval *t* for the defined set of generating resources *G*.

$a_i$ Is a multiplier representing effectiveness for the resource *i* in meeting Minimum Online Capacity requirement

$Y_{i,t}$ Is the commitment status for market resource *i* for interval ***t,*** $\in \{0,1\}$

$P_{i,t}^{\max}$ Is the total maximum operating limit of the market resource *i* and interval *t*, as de-rated by SLIC of the resource

2. 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. This enhancement is expected to be implemented in April 2010.

3. Multi-Stage Generating Unit Modeling – This action is focused on modeling combined cycle and reducing ramp issues caused by the lack of 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 remains at an operating level in order to maintain its ramping capability in an operational range. This enhancement will be implemented in a phased approach that deploys the forbidden operating region functionality on April 1, 2010 and extends the release of the full Multi Stage Generating Unit Modeling functionality until fall 2010.

4. Renewable Portfolio Standard Forecast – This action focuses on forecasting wind and solar later to better manage volatilities that cause congestion or ramp infeasibilities. The introduction of additional intermittent forecasting capability will allow the market to be responsive to these changing conditions. In doing so, there may be some reduction in need for exceptional dispatch

that may take place as a result of these conditions, including congestion that may occur. The implementation date of this enhancement is to be determined.

5. 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. This enhancement is expected to be implemented in the second quarter of 2010.

6. 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.

7. Multi-Day Commitment –The multi-day commitment and other potential initial condition enhancements will reduce the need to use exceptional dispatch bridging to avoid unnecessary cycling of resources that can occur with a single-day commitment horizon. This enhancement will come up for review after the ISO completes the design phase of its convergence bidding project. It currently appears that the ISO will start to look at this in the first or second quarter of 2010 and would implement it after that time.

8. Transmission Upgrades to Transmission System 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).

9. 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. The ISO is also developing a RUC nomogram to reflect a third major operating procedure that covers the San Diego area (G-206). However, since minimum load energy and other capacity from units committed in RUC is not available in the IFM market, the Department of Market Monitoring has recommended that these constraints be incorporated in the IFM market model if possible. This will reduce excess generation in the real-time markets (HASP and RTD) resulting from minimum load committed after the IFM and will also provide resources needed for these constraints with additional opportunity for market revenues in the IFM. The ISO is currently developing procedures to incorporate these capacity constraints in the IFM and expects to have these implemented in late fourth-quarter of 2009 or early 2010.

10. 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.

11. New Market Products - As described in the ISO's most recent 120-day report to FERC, the ISO has committed to a process over the next nine months to consider potential new products.[8] The ISO believes that to effectively and efficiently analyze the need for new products, it is necessary to have a full year of operational experience and information before determining what, if any, specific new products or market design enhancements can most effectively mitigate the volume of future exceptional dispatches. This will also allow the ISO to implement any additional software and operational improvements that may resolve many of the exceptional dispatch issues. The ISO believes that this approach is prudent, particularly in light of the operational and software improvements that have been implemented to reduce exceptional dispatch. During the second quarter of 2010 the ISO will transition the current stakeholder process from (1) changes to modeling and software and operational practices, to (2) the potential development of new market products - A stakeholder process will commence during the second quarter of 2010 to consider design enhancements that may be needed to mitigate the level of exceptional dispatches and to meet future operational needs in light of state environmental goals.

[8] The October 20, 2009 report to FERC is available at http://www.caiso.com/244d/244ddae36eed0.pdf.

# 4 Reasons for Exceptional Dispatch

This section describes the reasons for exceptional dispatch, including the reason codes established by the ISO to track and report exceptional dispatch.[9]

## 4.1 Generic Reasons for use of Exceptional Dispatch

Adequate reactive power is needed at all times in proximity to various load pockets in order to prevent instantaneous voltage collapses and to ensure grid reliability. Transmission equipment is rated by its ability to withstand prolonged excess load, and these equipment ratings are incorporated into capacity limits for transmission facility networks, known as nomograms. In addition to simply needing units online for their reactive power, these requirements specify that unloaded real power capacity be available throughout the grid, to ensure that transmission components can return to their thermal rated limits within a time frame of roughly 15 to 30 minutes, in the event those limits are exceeded. Voltage stability and thermal limit reliability problems can arise as a result of unexpected deviations of load from local, regional, and system-wide load forecasts, as well as from unexpected generator and transmission component contingencies. Outside of spinning and non-spinning reserves, the ISO's market software does not dispatch capacity for handling contingencies. Spinning and non-spinning reserve markets do not adequately specify the required locations of capacity for all of the system's reliability needs.

Beyond the broad zonal designations of spinning and non-spinning reserves, the market software's ability to dispatch resources to prevent reliability problems in the face of contingencies or load forecast errors is limited to what can be modeled as flow limit constraints. Nearly every transmission system component has its thermal flow limit modeled as a constraint by the market software. Under normal operating conditions, the software is able to ensure that no thermal constraints are violated. If a generator or transmission system component fails, however, thermal constraints may change and can be violated. Given that the software does not know how to commit the locational generation capacity that would be required to avoid the reliability problems that would arise as a result of contingencies, flow limits must be constrained to levels that would protect many of the major transmission components if a contingency were to occur. The software directly models many major transmission system contingencies, constraining all pre-contingency dispatches so that major transmission components would not be overloaded if any single "modeled contingency" were to occur. Engineers have also defined hundreds of nomograms that limit the flows over combinations of transmission system components in order to protect those components from suffering thermal limit violations after many possible system contingencies.

It is unrealistic to expect that these flow limit nomograms and modeled contingencies can fully replace exceptional dispatch for several reasons. First, the nomogram constraints and modeled contingencies are limited to major transmission components due to the desire for the software to complete its optimizations in a reasonable amount of time. Nomograms cannot reasonably be created to keep real-time flow limits of all minor transmission lines at levels such that an outage of a particular small transmission line would not overload some other nearby small transmission line. Moreover, the software does not model generation contingencies at all.

Second, the energy dispatch that satisfies the flow limit nomograms may not satisfy either the voltage or thermal constraint capacity needs for specific load pockets. The software does not

[9] This section is based on Exceptional Dispatch section presented in the DMM's Q2 Report which is published on the CAISO website at http://www.caiso.com/2425/2425f4d463570.html.

consider at all the reactive power needed to maintain voltage stability within the system's various load pockets. Nomograms and modeled contingencies can help to ensure that there is enough energy within the load pockets to prevent thermal violations after a contingency. However, that energy could, for example, be from a single large unit, rather than the variety of units needed for voltage support in locations throughout a load pocket. Similarly, available capacity may be needed in more specific locations to protect against potential thermal constraint violations of "smaller" components.

Furthermore, the software only does limited modeling of neighboring balancing areas. Therefore, it cannot accurately model the actual flows over many inter-ties or transmission system components that receive a large percentage of their flows from an inter-tie. Nomograms in the software or modeled contingencies can only commit capacity and dispatch energy to limit *market* flows. When these market flows are known to differ substantially from actual flows, the related nomograms and modeled contingencies are not defined in the software. Instead, day-ahead actual flows are estimated outside of the software and exceptional dispatches may be needed to provide corrective generation capacity in various ISO regions in order to protect the system's reliability from outages of inter-ties or nearby transmission components.

Finally, while the capacity of a de-rated transmission line can be input to the software for the Real-Time Unit Commitment ("RTUC") run following the de-rate, in practice, the nomograms for surrounding lines take some time to be updated after a forced transmission outage, as this necessarily involves manual work. In rare cases, exceptional dispatches for both capacity and energy are used as proxies for the nomograms until the outages are entered. Even with planned transmission outages, the software still has the same limitations concerning the modeling of reactive power and the inability to dispatch capacity to correct possible thermal constraint violations. Therefore, exceptional dispatch must be issued after planned transmission outages for the same reasons they are issued under normal operating conditions. There will be a need for *more* exceptional dispatches after planned transmission outages, however, because the components being protected from the new set of "next" possible contingencies are more heavily loaded due to the original planned outage.

## 4.2 Specific Reasons used for Exceptional Dispatch

As discussed above, whenever the ISO issues an exceptional dispatch instruction, such instructions are logged into SLIC, including the associated reason. These reasons are associated with the constraints that are not currently incorporated or enforced in the market application. In addition to constraints, the ISO also issues exceptional dispatch instructions for software failures.

The ISO has developed a system to track the reasons for exceptional dispatches. This system includes reasons and instruction type codes.[10] Table 1 provides the most current listing of the categories. These reason codes can be broadly classified into local generation requirements, transmission management requirements, non-modeled transmission outages, intertie emergency assistance, voltage support, black start capabilities, software limitations, unit testing and other requirements, such as ramp requirements and load forecast uncertainty. The ISO also issues exceptional dispatch instructions for software failures which are also known as market disruptions. Exceptional dispatch reasons that are most frequently issued are explained in the subsections below.

[10] These reason codes and instruction types are published on the ISO website as an appendix to M-402C Exceptional Dispatch Instruction Type Codes at http://www.caiso.com/thegrid/operations/opsdoc/marketops/index.html.

**Table 1: Exceptional Dispatch Instruction Type Codes**
**(From ISO Operating Procedure M-402C, Version 1.3, Effective 11/24/09)**

| Reason | Instruction Type (EDE Code) | Instruction Description |
|---|---|---|
| Black Start | BS | Black Start |
| Bridging Schedules | NONTMOD | ED for System Reliability to Bridge a unit schedule that would otherwise end and allow unit to shutdown because software doesn't consider beyond 24 hours, and with minimum down time, minimum start time, and minimum run times may cause starting a comparable unit, which not only may have increase overall costs (considering startup), but more importantly may increase risk to reliability if problems occur during start of other unit. A unit already online is generally more reliable than a unit that needs to be started. |
| Commitment Instruction | TMODEL | ED for System Reliability to reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC |
| Delta Dispatch | NONTMOD | ED to address software and modeling limitations that are not due to a Transmission related modeling limitations including environmental and resource constraints such as ramping limitations |
| Dispatch Modification | NONTMOD | ED to address software and modeling limitations that are not due to a Transmission related modeling limitations including environmental and resource constraints such as ramping limitations |
| Contingency | SYSEMR | Energy needs following a contingency to meet the reliability requirements |
| Emergency Assistance | TEMR | Tie Emergency (emergency energy transaction with other BAs) |
| G-206 San Diego Area (for competitive constraint, not for TNA commitment specifically requested by SDG&E) | TMODEL3 | Competitive Path SDG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| G-206 SDG&E Area (for TNA commitment specifically requested by SDG&E, or for non-competitive constraint) | TMODEL7 | Non-Competitive Path SDG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| G-217 South-of-Lugo | TMODEL | ED for System Reliability and to mitigate for over-gen, or a Market Disruption; reverse commitment instruction; and reverse operating mode of Pumped Storage unit |

| Reason | Instruction Type (EDE Code) | Instruction Description |
|---|---|---|
| G-219 - SCE Area (for competitive constraint) | TMODEL2 | Competitive Path SCE - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| G-219 SCE Area (for non-competitive constraint) | TMODEL6 | Non-Competitive Path SCE - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| G-233 - Bay Area (for non-competitive constraint) | TMODEL5 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| G-233 Bay Area (for competitive constraint) | TMODEL1 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Market Disruption | SYSEMR | ED for System Reliability due to a Market Disruption or to prevent a Market Disruption or to minimize the extent of a Market Disruption |
| N/A | RMRR | RMR Contract Energy |
| N/A | RMRS | RMR/Substitution |
| Other | OTHER | Use "OTHER" when there is insufficient information in real-time to determine the reason. A later correction of the code is expected between Grid Ops, Market Ops and Settlement teams. |
| Transmission Outage not identified with an Operating Procedure | TMODEL | Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; and (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| OverGeneration | SYSEMR | ED for System Reliability to dispatch units as necessary to relieve overgeneration to prevent a situation that threatens System Reliability |
| Path 15 or Path 26 | TMODEL | ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| Pumped-Storage | SYSEMR | ED for System Reliability to reverse the operating mode of a Pumped-Storage Hydro Unit |
| Ramp Rate | NONTMOD | ED to address software and modeling limitations that are not due to a Transmission related modeling limitations including environmental and resource constraints such as ramping limitations |
| Reliability need cannot be met by other resources | RMRRC2 | RMR Energy Condition 2 - Reliability need cannot be met by other resources |

| Reason | Instruction Type (EDE Code) | Instruction Description |
|---|---|---|
| SLIC Derate | SLIC | Dispatches due to SLIC re-rates (e.g. Derate Energy) |
| Software Limitation | NONTMOD | ED to address software and modeling limitations that are not due to a Transmission related modeling limitations including environmental and resource constraints such as ramping limitations |
| SP26 Capacity | TMODEL | ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| System Capacity | SYSEMR | ED for System Reliability for additional capacity not committed through the IFM or RUC needed for system requirements due to adverse weather conditions, fires, Temperature Forecast error, margin or Thermal Margin or capacity to increase spinning reserve to prevent situations that may threaten system reliability. (Note: System Capacity reason logged in SLIC will also require a second dropdown box to identify the specific need to support the System Capacity reason) |
| T-103 - for competitive constraints | TMODEL | Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| T-103 - for non-competitive constraints | TMODEL4 | Non-Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| T-129 - for competitive constraints | TMODEL1 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-129 - for non-competitive constraints | TMODEL5 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-132 - for competitive constraints (NOT T-132E for Miguel or IV commitment) | TMODEL3 | Competitive Path SDG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-132 - for non-competitive constraints (NOT T-132E for Miguel or IV banks) | TMODEL7 | Non-Competitive Path SDG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |

| Reason | Instruction Type (EDE Code) | Instruction Description |
|---|---|---|
| T-132E - for competitive constraints | TMODEL | Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| T-132E (NOT T-132 SD Area Local) for non-competitive constraints | TMODEL4 | Non-Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| T-133 - for competitive constraints | TMODEL1 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-133 - for non-competitive constraints | TMODEL5 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-135 - for competitive constraints | TMODEL | Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| T-135 - for non-competitive constraints | TMODEL4 | Non-Competitive Path - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network not associated with a particular TO or more than one TO |
| T-137 - for competitive constraints | TMODEL2 | Competitive Path SCE - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-137 - for non-competitive constraints | TMODEL6 | Non-Competitive Path SCE - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-138 - for competitive constraints | TMODEL1 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-138 - for non-competitive constraints | TMODEL5 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |

| Reason | Instruction Type (EDE Code) | Instruction Description |
|---|---|---|
| T-154 - for competitive constraints | TMODEL1 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-154 - for non-competitive constraints | TMODEL5 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-165 - for competitive constraints | TMODEL1 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| T-165 - for non-competitive constraints | TMODEL5 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Telemetry Error | SYSEMR | ED for System Reliability to mitigate for over-generation, a Market Disruption; reverse commitment instruction or reverse operating mode of Pumped Storage unit |
| TOR/ETC - Competitive Constraints | TORETC | Competitive Path - ED for TOR or ETC Schedule Changes after HASP |
| Transmission Outage - PG&E - for competitive constraints | TMODEL1 | Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Transmission Outage - PG&E - for non-competitive constraints | TMODEL5 | Non-Competitive Path PG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Transmission Outage - SCE - for competitive constraints | TMODEL2 | Competitive Path SCE - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Transmission Outage - SCE - for non-competitive constraints | TMODEL6 | Non-Competitive Path SCE - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Transmission Outage - SDG&E- for competitive constraints | TMODEL3 | Competitive Path SDG&E - ED associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |

| Reason | Instruction Type (EDE Code) | Instruction Description |
|---|---|---|
| Transmission Outage - SDG&E - for non-competitive constraints | TMODEL7 | Non-Competitive Path SDG&E - ED  associated with modeling limitations that (1) arise from transmission maintenance; (2) lack of Voltage Support at proper levels; or (3) incomplete or incorrect information about the transmission network |
| Unit Testing | ASTEST | Ancillary Service Testing |
| Unit Testing | PRETEST | Pre-commercial operations or PMax testing for generators |
| Unit Testing | RMRT | RMR Test Energy |
| Voltage Support | VS | Provide for Voltage Support (other than for Energy needed for Voltage Support) |

### 4.2.1 Generation Procedures

All reason codes starting with "G" refer to an ISO operation procedure for local area generation requirements. The G procedure reason code is used for dealing with capacity for voltage stability and thermal constraints requirements for a local area. For instance G-219 defines the generation commitment requirements for the Orange County area, a large load pocket within Southern California Edison territory. Most of the generation procedures are internal to the ISO and not available on the ISO website.

### 4.2.2 SP26 Capacity

This is a zonal requirement based on forecast load for SP26 for which the ISO commits units in the day-ahead market. Nearly any resource within Southern California can contribute to meeting this requirement.

The SP26 Capacity reason is logged when an exceptional dispatch is issued to commit a unit to meet capacity requirements in the area south of Path 26 (Southern California). The capacity requirements are to protect that area against loss of the Pacific DC intertie. The current software does not address a contingency of the Pacific DC intertie. Therefore, exceptional dispatches may be issued to ensure there is enough online capacity to mitigate any thermal constraints in the region within 20 minutes of the intertie outage.

### 4.2.3 System Capacity

Exceptional dispatch instruction for System Capacity helps to meet generation capacity requirements for the entire ISO region due to load forecast uncertainty or lack of enough online thermal capacity. The defined generation requirements protect the area from the potential voltage stability and thermal constraint problems faced by smaller regions, as discussed in the previous subsections. The ISO should retain online generation capacity sufficient to avoid a system-wide voltage collapse. System Capacity is only used in practice for ensuring there is enough online capacity in California to meet demand in the event of a series of worst-case scenarios simultaneously occurring.

### 4.2.4 Transmission Procedures

All reason codes starting with "T" refer to an ISO operating procedure for transmission facilities. Public transmission (and generation) procedures are available on the CAISO website[11]. T-Procedures describe the measures that should be taken when a transmission system component in or into a particular region has its thermal constraint violated. Each T-Procedure is for the transmission system of a certain region. For example, T-132 is for the San Diego area, T-133 is for the Bay Area, T-138 is for the Humboldt area, and T-129 is for the Fresno area. The T-Procedures also specify the effectiveness of generating units in the area for mitigating congestion on a particular component. Furthermore, T-Procedures define many of the nomograms for limiting the simultaneous flows on many transmission components so that, as described in the previous section, if certain contingencies occur, the components will not be overloaded. Many T-Procedures also specify the acceptable voltage ranges of many buses within the T-Procedure's area, as well as the effectiveness of voltage control equipment for mitigating voltages going outside the acceptable ranges of the buses.

---

[11] A list of all of the ISO's publicly available Operating Procedures are available at the following link: http://www.caiso.com/thegrid/operations/opsdoc/index.html

### 4.2.5 Transmission Outage

Exceptional dispatch instructions labeled as Transmission Outage serve as workarounds for the same reactive power and corrective capacity modeling limitations of the software discussed in the previous sections. Only a small fraction of exceptional dispatches for energy that are logged as being for a Transmission Outage are for mitigating actual violations of thermal constraints. When there is a transmission outage, the RTM software is updated to dispatch energy in accordance with the line's outage by the very next RTUC run. Therefore, there is generally no need to issue an exceptional dispatch to commit a unit to provide energy in response to a transmission outage, except when nomograms that would limit pre-"next"-contingency flows on surrounding lines are not defined in the software.

Most exceptional dispatches labeled as Transmission Outages are issued to commit capacity for known Transmission Outages. For the duration of a scheduled outage, many next credible contingencies (single or double) would cause voltage violations. The voltage impacts of the next contingency cannot be simulated by the market software. Therefore, exceptional dispatches may be needed to commit enough capacity to maintain voltage stability. On the other hand, an outage may result in concern over nearby transmission system components (whose market flow after contingencies has not been constrained by nomograms or modeled contingencies) having their thermal limits violated after the "next" contingency. Most Transmission Outage exceptional dispatches for capacity are due to planned outages of inter-ties or lines that received a significant portion of their flows from inter-ties. Most of those exceptional dispatches provided corrective capacity for post-"next"-contingency thermal constraint violations.

Similarly, most Transmission Outage exceptional dispatches for dispatch energy are during planned transmission outages of transmission components that are electrically close to an inter-tie. Due to the inability to accurately model the actual flows on these and nearby lines, some nomograms for limiting pre-"next"-contingency actual flows to levels that would be safe post-"next"-contingency are not entered into the software. Instead, actual flows are monitored by operators who issue exceptional dispatches if the actual flows violate the nomogram.

### 4.2.6 Software Limitations

Operators log "Software Limitations" as the reason for exceptional dispatches that must be issued as a result of the system software not performing a function that it is supposed to be able to do and that it normally does for most generators. One could of course view every exceptional dispatch as a "Software Limitation", but the software is not designed to be able to dispatch capacity for corrective reliability reasons, or for voltage stability. The software is, however, designed to respect generator characteristics (besides Forbidden Regions) such as minimum run times or minimum down times. Sometimes the software will dispatch a unit with a minimum run time of an hour for a single five-minute interval. Or, the software may dispatch a unit that has a minimum down time of four hours to start-up an hour after shutting down. In these cases, exceptional dispatches will be issued to force the dispatch to comply with the generators' physical characteristics. Because these are characteristics that the software is designed to recognize in its automated dispatches, the operators will log the exceptional dispatch as being due to "Software Limitations". Another category of software limitation includes exceptional dispatches used to "bridge" across daily RUC commitments. After G-217 and G-219 were implemented in RUC, operators observed that the RUC algorithm frequently turned resources on at approximately HE 6:00, and/or shut resources down late in the evening, as they were needed primarily during peak hours. Because an operation day's RUC market run is independent of the following day's RUC market run, the following day's RUC optimization recognized a shut-down unit's minimum down time, and thus often started a different resource.

This frequent startup and shutdown pattern is costly and imposes wear and tear on resources. Operators thus began the practice of keeping units on overnight to “bridge” across the two different market runs, in order to avoid costly shutdowns and startups. These bridging exceptional dispatches typically are included in the reason category of “software limitation” because they reflect the inability of the market software to optimize across inter-temporal market runs.

### 4.2.7 Ramp Rate or Dispatchable PMin

When the ISO issues a day-ahead exceptional dispatch commitment, the resource is turned on and will sit at minimum load, unless it is economic and participates in the market. At minimum load, most resources that receive exceptional dispatches have very low ramp rates; that is, they take a long time to move from their minimum levels of output upward to respond to dispatch instructions. In order to ensure that committed units are responsive, ISO operators can issue *Ramp Rate* exceptional dispatch energy instructions, which instruct units to ramp up to higher levels of output, where they can be moved up and down quickly by the market software. All Ramp Rate exceptional dispatch energy instructions are issued in real-time. The majority of energy from exceptional dispatches above PMin comes from this Ramp Rate, or Dispatchability reason. Unlike the dispatch energy requirements for generation and transmission procedures, dispatches for Ramp Rate have little to do with the energy that is dispatched. Instead, they are dispatches for getting the unit to an output level at which the unit has more available capacity for mitigating thermal constraint violations from possible “next” contingencies. Some generating units have ramp rates that vary with the unit’s current MW output level. For example, a unit may only be able to ramp 1.6 MW/min when it is operating at its PMin of 20 MW. However, when the unit is operating at an output level in the range of 70-150 MW, then its ramp rate is 6.4 MW/min. As described above, the software currently cannot dispatch capacity for correctively responding to a possible “next” contingency. However, unloaded capacity is needed in regions of various sizes to mitigate violations of thermal constraints after a potential “next” contingency. This unloaded capacity is specifically needed for lines whose flows after possible contingencies are not limited pre-contingency via nomograms or “modeled contingencies”. The effective 20-minute unloaded capacity of a unit with a 6.4 MW/min ramp rate is 128 MW, four times the same unit’s effective 20-minute unloaded capacity when the unit is operating at its PMin. Therefore, when a unit is operating at a level where it has a low ramp rate and the system needs the unit’s capacity for the thermal limit reliability reasons described above, the operator will issue an exceptional dispatch to just get the unit into its maximum ramp rate output range. Another reason Ramp Rate exceptional dispatch energy is used is to move resources that have Contingency reserves awarded at a higher ramp rate than the resource is currently operating at. The current software design does not consider where a resource is scheduled at when awarding Contingency reserves. (Spin and Non-Spin). To ensure the ISO is able to meet its Contingency Reserve Requirements, a resource may need to have its out-put increased to a level where it has ramping capability to be able to provide its awarded Contingency Reserve. This issue will be greatly resolved with the implementation of Multi-Stage Generating Unit Modeling.

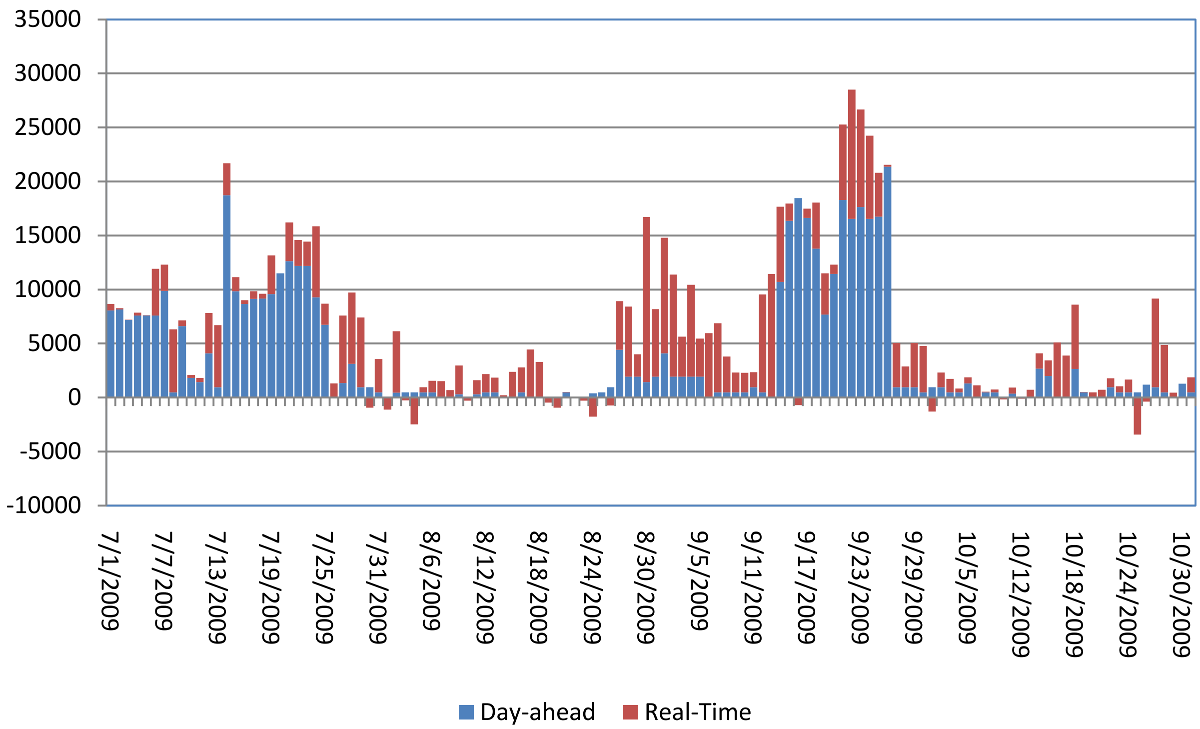
# 5 Exceptional Dispatch Trends[12]

In this report exceptional dispatches are measured in four ways. The first set of metrics shows the volume in MWh, the second set of metrics show the volume of exceptional dispatch as a proportion of total load, the third set of metrics show the exceptional dispatch volume classified by hours, and the last set of metrics show classification of exceptional dispatch by frequency.

## 5.1 Exceptional Dispatch Volume by Market Type

Figure 1 shows exceptional dispatch volume by market type for the period from July 1, 2009 through October 31, 2009. During this period the total volume of exceptional dispatch was 781,228 MWh. Almost 60 percent of exceptional dispatch volume was driven by pre-Day-Ahead exceptional dispatch and the remaining 40 percent of volume was due to Real-Time exceptional dispatch. All of the pre-Day-Ahead exceptional dispatches were unit commitments at the resource physical minimum. The Real-Time exceptional dispatches were either one of the following types: a unit commitment at PMin, an incremental dispatch above the Day-Ahead schedule, or a decremental dispatch below the Day-Ahead schedule.

Figure 1: Exceptional Dispatch Volume (MWh) by Market Type



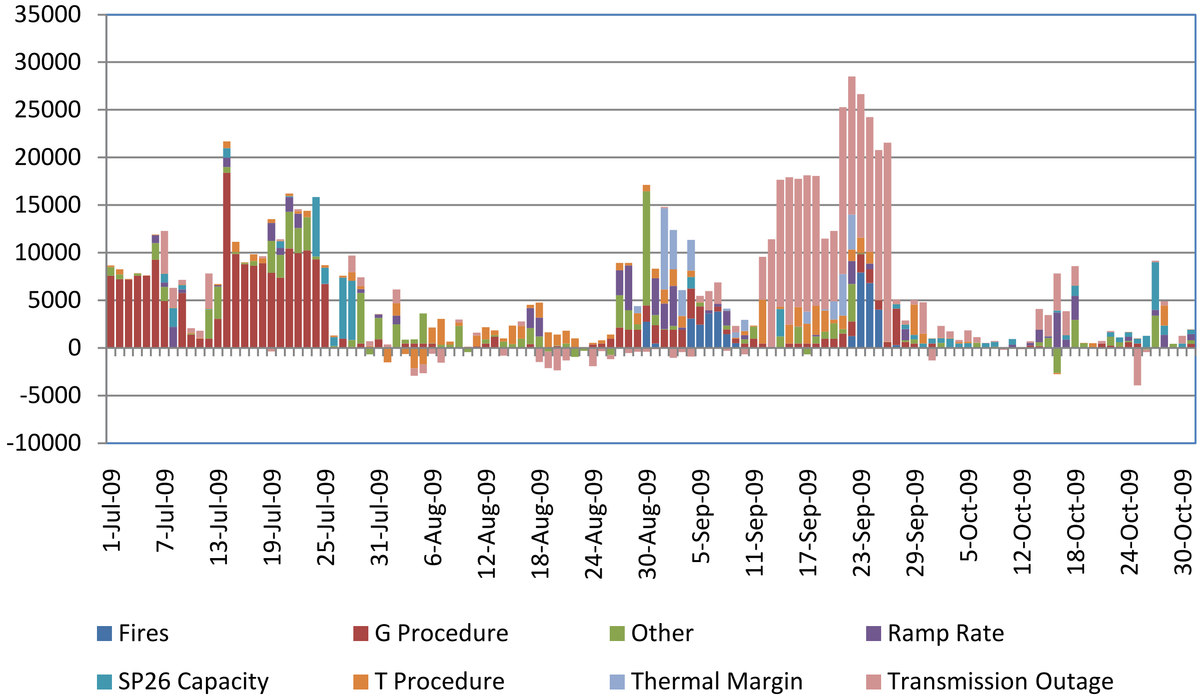

[12] Data used to create graphs in this report is principally SLIC information supplemented with data from the Market Quality System. It is the most accurate currently available and it is worth noting that this data has been through the T+38B initial statement process wherein many unresolved issues are fixed.

## 5.2 Exceptional Dispatch Volume by Reason

Figure 2 shows the exceptional dispatch volume by reason for the period from July 1, 2009 through October 31, 2009. 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 majority of exceptional dispatch volume was driven by generation procedures (30 percent), transmission outages (28 percent) and transmission procedure (8 percent).

The higher level of exceptional dispatches that occurred in mid to late September 2009 was due to a forced outage of the Southwest Power Link (“SWPL”) between Hassayampa and North Gila in Arizona. SWPL is a primary conduit of power into San Diego, and its outage also caused a de-rate of the Palo Verde branch group, affecting imports coming into Southern California. This outage coincided with ongoing repairs to Los Angeles-area transmission following the Station Fire. After this period the level of exceptional dispatches dropped significantly as those facilities returned to service and allowance for market solution returned. Of all months shown in this analysis, July (36 percent) and September (47 percent) saw the most significant volume of exceptional dispatches. In July, more than 66 percent of exceptional dispatch volume was driven by driven by generation procedure. Of the 66 percent, the G-217 (South-of-Lugo) and G-219 (Orange County) generation procedures account for 48 percent and 20 percent of exceptional dispatch volumes. In August almost 30 percent of exceptional dispatches were due to fires in SCE area and issues in the Fresno area. During the last week of August and in almost all weeks in September real-time exceptional dispatches in the Fresno area were necessary due to transmission constraints related to remedial action schemes which are not fully modeled or incorporated into the market applications. These did result in exceptional dispatches that limited some pump run time and constraining some hydroelectric generation online. In September almost 56 percent of exceptional dispatch volumes were driven by transmission outages. Exceptional dispatches labeled as Transmission Outage serve as workarounds for the same reactive power and corrective capacity modeling limitations of the software discussed in the previous section. These must be exceptionally dispatched because the IFM procures to balance power supply and demand, and is not currently designed to incorporate these types of constraints. In addition, during these outages there is limited ability to create new corridors except by creating temporary nomograms referring to existing corridors. To address this, the ISO is seeking additional software flexibility to define new corridors constraints, outside of the four to six-week week model build process. In October the volumes of exceptional dispatches decreased significantly to 7 percent of the total compared with 47 percent in September. The majority of exceptional dispatch volumes in October were due to capacity requirements in the SP26 area (29 percent) and ramp rate reason (22 percent).

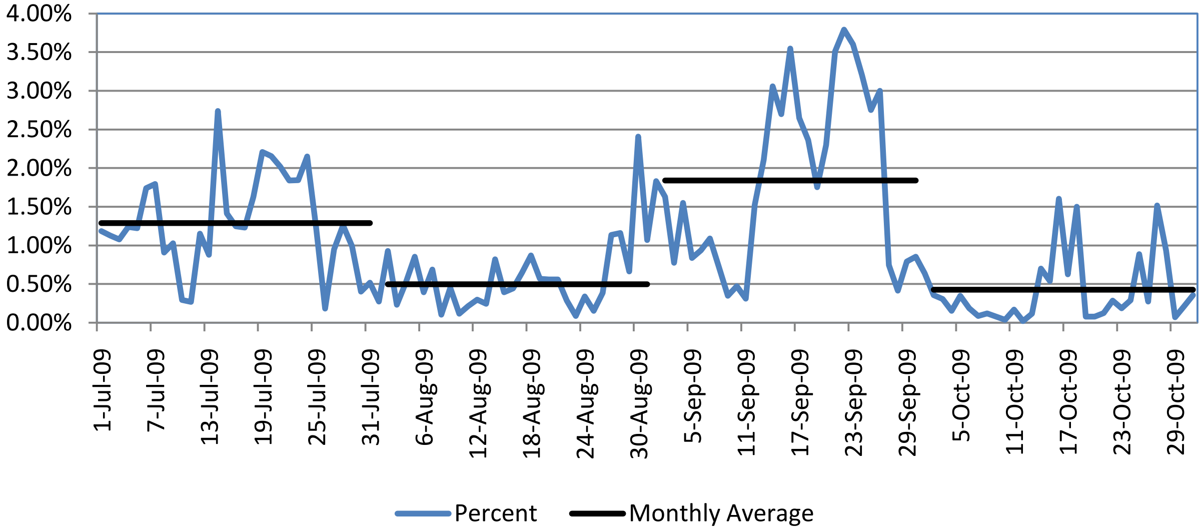
Figure 2: Exceptional Dispatch Volume (MWh) by Reason



## 5.3 Exceptional Dispatch as Percent of Load

Figure 3 shows the total exceptional dispatch as a percent of load and it also shows the average percentage for each month. September saw the highest monlthly average of 1.84 percent and October saw the lowest average of 0.43 percent. The monthly average percentages for July and August were 1.29 perent and 0.50 percent, respectively.

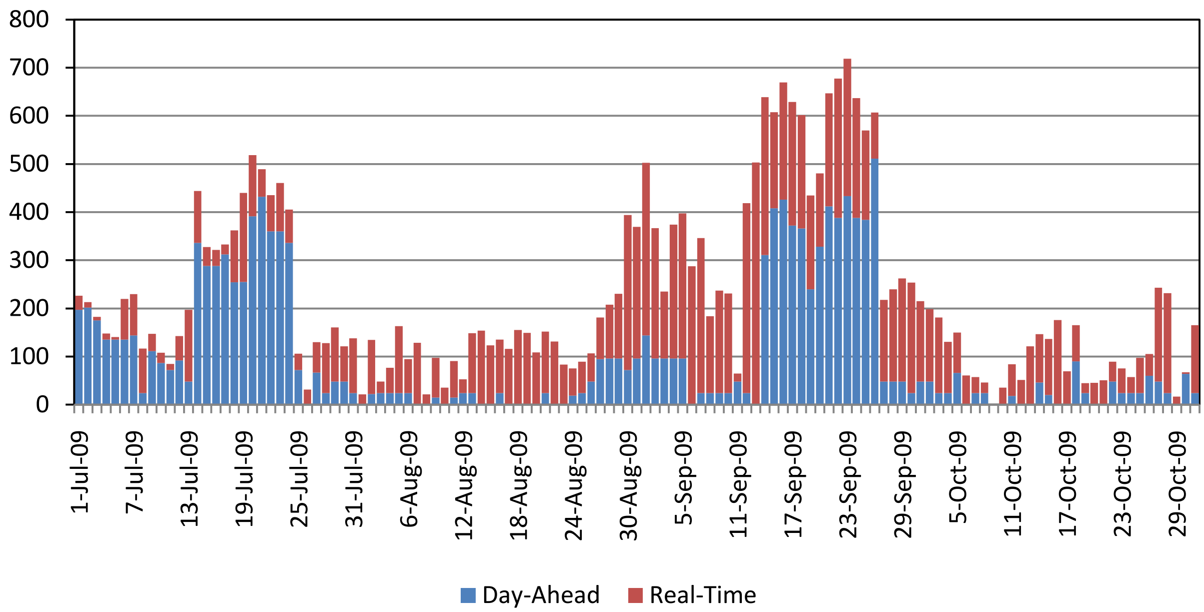
Figure 3: Total Exceptional Dispatch as Percent of Load



## 5.4 Hours of Exceptional Dispatch by Market Type and Resource

Figure 4 shows the hours of exceptional dispatch issued from the beginning of July 2009 until then end of October 2009 classified by market type. The total hours of exceptional dispatches calculated as sum of hours for each resource that was issued an exceptional dispatch. During this period the ISO issued exceptional dispatch for a total of 27,937 hours. Of the total, 46 percent (12,869 hours) were due to exceptional dispatch in the Day-Ahead Market, but 60 percent of exceptional dispatch volume was due to Day-Ahead exceptional dispatch instructions. The exceptional dispatch instructions in RTM were driving 54 percent (15,068 hours) of total hours of exceptional dispatch, and it contributed to 40 percent of exceptional dispatch volume.

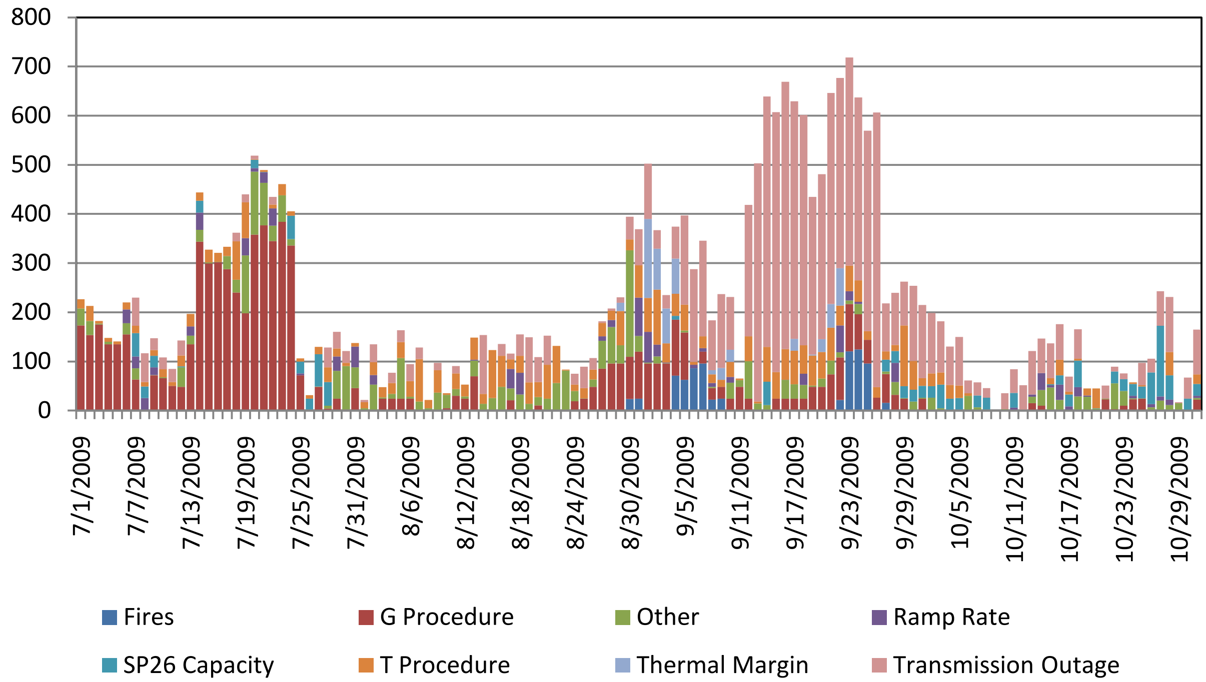
Figure 4: Hours of Exceptional Dispatch by Market Type and Resource



## 5.5 Total Hours of Exceptional Dispatch by Reason and Resource

Figure 5 shows the hours of exceptional dispatch from the beginning of July 2009 till the end of October 2009 classified by reason. The majority of hours of exceptional dispatch were due to Transmission outage (39 percent), Generation procedures (26 percent) and Transmission procedures (12 percent). Of all months, the month of September saw the highest hours (47 percent) of exceptional dispatch and October saw the least hours (12 percent) of exceptional dispatches.

Figure 5: Total Hours of Exceptional Dispatch by Reason and Resource

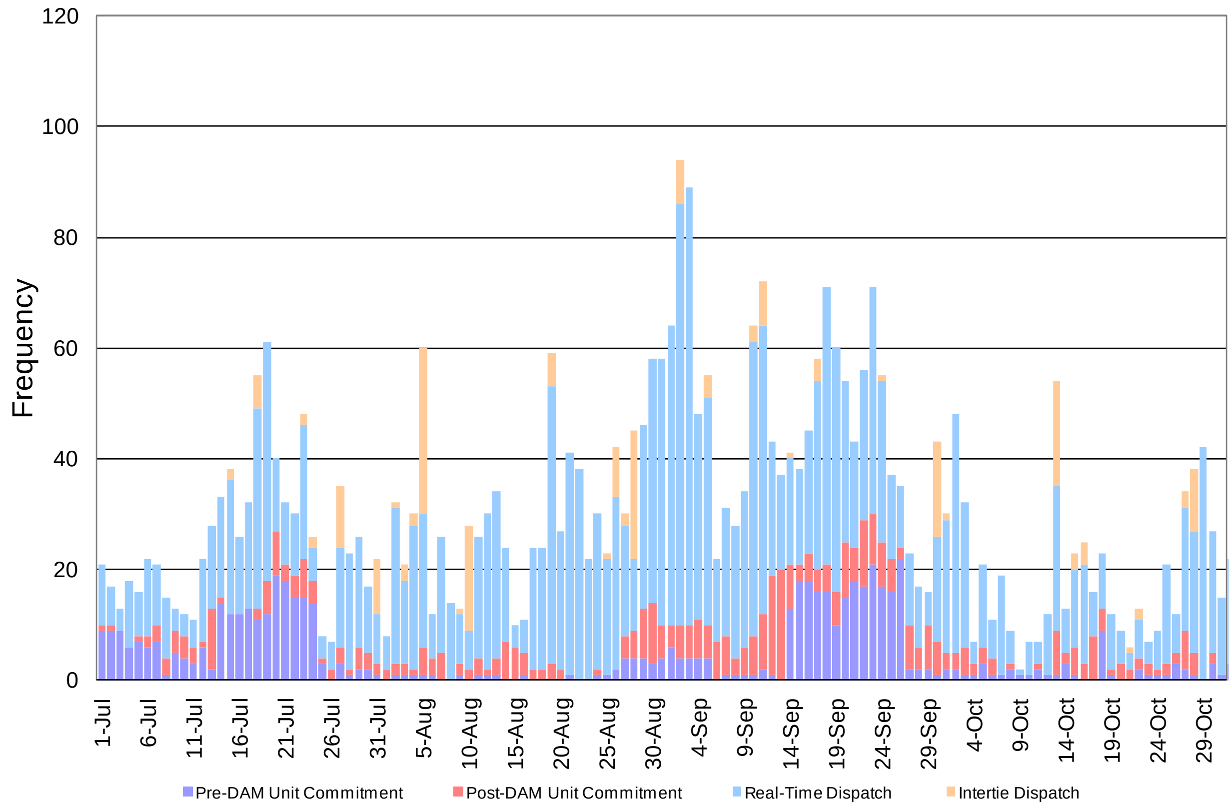


## 5.6 Daily Exceptional Dispatch Frequency by Market Type and Resource

Figure 6 shows the frequency of exceptional dispatch by market type and resource for the period from July 1, 2009 through October 31, 2009. The data shown is based on logs entered in the SLIC database. As discussed above, due to the manual nature of logging exceptional dispatch, this graph does not contain all exceptional dispatch instructions. However, this is the only graph that can be used to classify exceptional dispatch instructions by various market timelines, namely: pre-Day-Ahead unit commitments, post Day-Ahead unit commitment, Real-Time dispatches and interties dispatches. All graphs shown in Figure 1 through Figure 5 are based on MQS data. Since the MQS system handles energy from Day-Ahead and Real-Time markets, the exceptional dispatch data in those graphs cannot be classified into more than two categories.

The total frequency of exceptional dispatch for the period shown in Figure 6 is 3718. Of the total, 66 percent were due to Real-Time exceptional dispatch, 15 percent were due to pre-Day-Ahead unit commitments, 13 percent due to post-Day-Ahead unit commitments and 6 percent due to intertie dispatch. The frequency or count of exceptional dispatch understates the importance of pre-Day-Ahead unit commitment because 60 percent of total volume was due to pre-Day-Ahead unit commitment, whereas the counts of pre-Day-Ahead unit commitment account for only 15 percent of the total frequency.

Figure 6: Daily Exceptional Dispatch Frequency by Market Type and Resource



# 6 Costs and Market Impacts

In December 2009 the ISO will post an updated technical bulletin or paper that will discuss the costs and market impacts of exceptional dispatch. The document will cover the settlements charge codes for exceptional dispatch, metrics used to show use to exceptional dispatch for either the monthly or the quarterly period, and the market impact of exceptional dispatch.

# 7 Approach for determining New Products

This section discusses the ISO's the new market products that stakeholders have suggested to reduce exceptional dispatch, and a methodology the ISO is considering to identify the operational drivers that may not be able to be addressed through operational or software enhancements that may be candidates for market design enhancements.

## 7.1 Products suggested by Some Stakeholders

The ISO is committed to reducing reliance on exceptional dispatch as appropriate. The ISO's efforts to date have resulted in operational and modeling enhancements that have reduced exceptional dispatch and increased reliance on market mechanisms.

During the stakeholder meeting on December 9, the ISO will discuss with stakeholders modeling and software solutions that can limit the need for exceptional dispatch, review the most recent exceptional dispatch data, and solicit stakeholder input on whether ongoing issues related to exceptional dispatch can be addressed by further modeling and operational improvements or whether potential new market products may be warranted.

Some stakeholders have expressed a strong desire to begin stakeholder discussions now of new market products. They believe that new market products may reduce the ISO's reliance on exceptional dispatch. For example, some stakeholders have asked that a 30-minute ancillary services product and/or a voltage support product be developed.

Regarding a new 30-minute ancillary services product, the concept ranked "high" in the ISO's Market Initiatives Roadmap process in 2008. As a result of this high ranking, in 2008 the ISO launched a stakeholder process to explore and discuss with stakeholders the potential benefits that a 30-minute ancillary services product could provide. At that time, considering that the new ISO market had not yet been launched, the ISO was unable to clearly identify tangible benefits that justified moving forward with the development of the new product. It was also unclear at that time whether or not a 30-minute product was the right product to address the integration of large amounts of variable renewable generation. Therefore, it was determined that rather than put the "cart in front of the horse" and potentially design a new ancillary services product that may not satisfy future mandates, the ISO would defer the idea of developing a 30-minute ancillary services product and take a broader look at the ancillary services market to identify needs and specifications for new products consistent with upcoming requirements around the integration of variable renewable resources. In the second quarter of 2010 the ISO plans to start a stakeholder process on enhancements to the ancillary services markets to address the integration of renewable resources. This comprehensive review of the ancillary service markets and products will include potential products to address exceptional dispatch dispatches related to operating or contingency reserves.

Regarding the need for a market product for voltage support services, in its February 20, 2009 Order on exceptional dispatch FERC stated:

> *FERC directs the CAISO to file a report within 120 days of the date of the Order that details the outcome of the stakeholder process and its plans for a long-term solution for procuring voltage support outside of Exceptional Dispatch. (Order at P 45)*

In its September 2, 2009 Order on exceptional dispatch, FERC characterized the ISO's position on this topic as follows:

> *With respect to the need for a competitive market product for voltage support services, the CAISO explains that it has determined that several additional*

*months of data are needed in order to make a stakeholder process on this issue meaningful. The CAISO states that it will initiate a stakeholder process after it has obtained the additional months of data and emphasizes that the ultimate conclusion as to whether a voltage support product is needed should await the outcome of that process. In addition, the CAISO notes that it will continue to assess the need for other, possibly more critical, products and services and may run stakeholder processes on these products in parallel with the stakeholder process on voltage support services. (Order at P 48)*

FERC further addressed this topic in its September 2, 2009 Order on exceptional dispatch as shown below. The ISO notes that in this paragraph FERC has moved away from directing development of specific products and instead directs the ISO to work with stakeholders to determine what products are necessary.

*In light of the clarifications this order makes to the CAISO's Exceptional Dispatch Reports, which should afford greater transparency into the use of Exceptional Dispatch, and based upon the fact that several months of data are now available, the Commission's expectation is that the CAISO's stakeholder processes should move forward in assessing the reasons underlying exceptional dispatches and addressing what market products and/or solutions may be developed to limit the CAISO's reliance on Exceptional Dispatch to situations that are rare and infrequent or genuine emergencies. The CAISO should work promptly with stakeholders to develop appropriate product(s) and/or enhancements for timely implementation of identified solutions. We acknowledge receipt of the June 22, 2009 Status Report and direct the CAISO to continue to report on the progress of the stakeholder processes at least every 120 days. Accordingly, the next report should cover approximately the first six months of MRTU. By that point in time, the CAISO and stakeholders should have a wealth of data to support meaningful stakeholder processes. We expect, therefore, that stakeholder processes will be well underway by the time of the next update and 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. (Order at P 51)*

The ISO believes that several additional months of operational data are needed in order to make a stakeholder process to determine what products might be necessary meaningful. While there is a significant amount of data currently available to review, the ISO has found that each operational season has presented the ISO with a different set of conditions that are leading to exceptional dispatch. Without a full year of operational experience, and with modeling and software improvements still in progress, the ISO believes that it is premature to begin a discussion of specific new products at this time.

The ISO believes that the most prudent approach at this time is to continue to focus resources on operational and modeling improvements first, so that the ISO and stakeholders can later then better determine what, if any, new products or product enhancements are needed. During the second quarter of 2010 the ISO will transition this exceptional dispatch stakeholder process from (1) changes to modeling and software and operational practices, to (2) the potential development of new market products to further reduce exceptional dispatch.

## 7.2 Operational Drivers of Exceptional Dispatch

To start a dialog now with stakeholders regarding the potential need for new market products, the ISO has begun the development of a methodology to be used going forward to analyze the drivers of exceptional dispatch. The ISO believes that such an approach will better target the need for new products. The objective of this new methodology is to obtain a robust, but focused, set of data to analyze. This is necessary because of the tremendous volume of day-to-day operational data (there is currently over 16,000 data points). A method is needed to separate the "wheat from the chaff."

The ISO analyzed exceptional dispatch data from July 1, 2009 through September 31, 2009. The data was consolidated by combining generation units to a single site and converting multiple hourly exceptional dispatches to a single daily event. 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 and others which would not be product-related as outlined by Table 2 below.

Table 2 – Exceptional Dispatches Reason Codes for Product Analysis[13]
(Preliminary – For Discussion with Stakeholders)

| Included | Reason Code | Sites/Days of Exceptional Dispatch | Operational Need | Software Limitation | Model Limitation | Mitigation Measure Implemented | Mitigation Measure to be implemented |
|---|---|---|---|---|---|---|---|
| No | Circulation | RT 8 / 11 | Manual method to reflect DC circulation | No | No | None | None |
| No | G-206 | DA 1 / 8<br>RT 3 / 13 | Local Area Minimum Online Capacity | Yes | No | None – New Procedure under review | Minimum Online Capacity |
| No | G-217 | RT 6 / 29 | Minimum Online Capacity for thermal and voltage contingency | Yes | No | RUC Nomogram | Minimum Online Capacity |
| No | G-219 | DA 1 / 1<br>RT 2 / 2 | Minimum Online Capacity for thermal and voltage contingency | Yes | No | RUC Nomogram | Minimum Online Capacity |
| No | G-233 | RT 1 / 1 | Local Area Minimum Online Capacity | Yes | No | None – New Procedure under review | Minimum Online Capacity |
| No | Generator Outage | RT 3 / 3 | 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 | RT 2 / 12 | External assistance to neighboring Balancing Authority | No | No | None | None |
| Yes | Load Forecast Uncertainty | DA 1 / 1<br>RT 10 / 15 | 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 | RT 57 / 97 | HASP Failure or Timeout | Yes | No | Reduce HASP failures | Continue to reduce failure rate |

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

| Included | Reason Code | Sites/Days of Exceptional Dispatch | Operational Need | Software Limitation | Model Limitation | Mitigation Measure Implemented | Mitigation Measure to be implemented |
|---|---|---|---|---|---|---|---|
| No | Model Issue | RT 18 / 24 | 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 | RT 7 / 8 | Force de-commit or secure additional export | No | No | No | Consider lower bid floor |
| Yes | NP26 Capacity | RT 1 / 1 | To account to post-contingency corrective measure (How to return to normal limits) | No | No | None | Incorporate post-contingency corrective measures into SCUC/SCED |
| Yes | Path 26 | DA 2 / 6<br>RT 13 / 22 | 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 | RT 6 / 42 | 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 | MSG/Forbidden Region |
| Yes | Region Reliability | RT 8 / 11 | 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 | RT 10 / 37 | 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 | DA 1 / 1<br>RT 67 / 174 | Ensure resource is holding level or commitment despite software issue | Yes | No | Variance Fixes | Implement MSG |
| Yes | SP26 Capacity | RT 8 / 11 | 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 | RT 3 / 3 | Ensure energy dispatched from | Yes | No | Address software issue | None |

| Included | Reason Code | Sites/Days of Exceptional Dispatch | Operational Need | Software Limitation | Model Limitation | Mitigation Measure Implemented | Mitigation Measure to be implemented |
|---|---|---|---|---|---|---|---|
| | Energy | | spin remained due software constraint | | | | |
| Yes | System Capacity | DA 2 / 2<br>RT 8 / 10 | To address short-term reserve shortages until market can respond. | No | No | None | None |
| Yes | System Energy | RT 28 / 51 | Post HASP adjustment to account for significant and rapid change in conditions. Prevent imminent system emergency | No | No | None | None |
| No | T-103 | RT 5 / 17 | SCIT- Intertie requirement | No | Yes | None | Explicitly model intertie constraint<br>Model external drivers |
| No | T-123 | RT 1 / 1 | Bay Area | No | No | None | None |
| No | T-129 | RT 13 / 173 | Fresno Area Load w/Remedial Action Scheme | No | Yes | None | Transmission upgrades<br>Incorporate Remedial Action Scheme into contingency constraint |
| No | T-132 | RT 7 / 26 | San Diego Area, complicated border loop-flow through external system | No | Yes | None | Consideration of nomogram solutions |
| No | T-135 | DA 1 / 8<br>RT 3 / 7 | Lugo-Victorville (Path 61) and Sylmar (Path 41) Overload Mitigation, complicated by border loop-flow through external system | No | Yes | None | Consideration of nomogram solutions and/or external model enhancements |
| No | T-138 | RT 3 / 89 | Local energy, use limited resources | Local congestion, | Load Distribution Factors | LDF improvements | LDF improvements<br>New more flexible resources |
| No | T-154 | RT 2 / 2 | Drum Area Operations, complicated by water | No | Yes | None | None |

| Included | Reason Code | Sites/Days of Exceptional Dispatch | Operational Need | Software Limitation | Model Limitation | Mitigation Measure Implemented | Mitigation Measure to be implemented |
|---|---|---|---|---|---|---|---|
| | | | management constraints | | | | |
| No | T-165 | RT 3 / 9 | Palermo – Rio Oso Area (RMR, water management) | No | No | None | None |
| No | T-167 | RT 1 / 1 | Tesla/Bellota Summer Operations | No | No | None | None |
| No | T-170 | RT 3 / 10 | Mirage-Tamarisk local Area with special load relief | No | No | None | None |
| No | Thermal Margin | RT 8 / 24 | 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 | DA 3 / 3<br>RT 33 / 148 | Specific outage condition | No | No | Intermittent deviation improvements | Add ability to create new corridors limit during outages |
| No | Transmission Outage SCE | DA 1 / 4<br>RT 11 / 20 | Specific outage condition | No | No | None | Add ability to create new corridors limit during outages |
| No | Transmission Outage SDGE | RT 12 / 16 | Specific outage conditions | No | No | None | Add ability to create new corridors limit during outages |
| No | Transmission Outage (Other) | DA 3 / 12<br>RT 10 / 15 | Specific outage conditions | No | No | None | Add ability to create new corridors limit during outages |
| No | Unit Test – Demand Response | RT 5 / 10 | Specific testing | No | No | None | None |
| No | Unit Testing | RT 7 / 14 | Resource Test | No | No | None | None |

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 of this approach are summarized below.[14]

| Consolidated Start | | | Potential Capacity | | | Potential Ancillary Services | | |
|---|---|---|---|---|---|---|---|---|
| | DA | RT | | DA | RT | | DA | RT |
| Sites | 16 | 170 | Sites | 4 | 3 | Sites | 0 | 45 |
| Days | 255 | 1161 | Days | 9 | 23 | Days | 0 | 90 |

The ISO recognizes that potential exceptional dispatches that could support a new product may have been eliminated from the final data set.  However, the intent of this approach is to arrive at a manageable data set with a higher probability that the root cause of the exceptional dispatch may support the development of a new product.  In determining the root cause for this subset of exceptional dispatches, the ISO will determine the underlying ISO operational requirements that led to the exceptional dispatch.  Focusing the analysis of the exceptional dispatch data in this way will guide identification of what if any operational needs warrant consideration of a new product solution or modification to existing products.  The results of the ongoing analysis will be part of the foundation for reviewing potential new products after exceptional dispatch data has been collected through a full year of operation.

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

# 8 Next Steps

The ISO requests that stakeholders provide written feedback to the ISO on exceptional dispatch. A template has been created for stakeholders to submit written comments to the ISO. The template will be finalized after the December 9 stakeholder meeting and posted on December 11 to http://www.caiso.com/1c89/1c89d76950e00.html. Written comments should be submitted to the ISO no later than December 30, 2009 to kjohnson@caiso.com. On January 5, 2010 the ISO will post the written comments that it has received. The ISO will consider stakeholder comments as it works to reduce exceptional dispatch.

On February 17, 2010 the ISO will submit its next "120-day" report to FERC on exceptional dispatch. This report will discuss the status of the stakeholder process and efforts to reduce exceptional dispatch.

The ISO will continue to publish exceptional dispatch reports each month. These reports can be found at http://www.caiso.com/241d/241dca223c760.html.

During the second quarter of 2010 the ISO will transition the current stakeholder process from (1) changes to modeling and software and operational practices, to (2) the potential development of new market products - A stakeholder process will commence during the second quarter of 2010 to consider design enhancements that may be needed to mitigate the level of exceptional dispatches and to meet future operational needs in light of state environmental goals.