Draft Catalogue of Market Design Initiatives

September 2010

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Prepared by

Market and Infrastructure Development

Catalogue of Market Design Initiatives

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1. Introduction

This Market Initiatives Catalogue contains a listing and description of all ongoing and potential future enhancements to the California ISO's (ISO) market design. The discretionary market design initiatives listed here are ranked annually through the Market Initiatives Roadmap Process. The outcome of that process is used to help determine the highest priority market design enhancements that the ISO should address that will provide the most benefit to the ISO and stakeholders. Due to the large volume of market enhancements in the queue for 2009-2010, the ISO does not plan to conduct the ranking process again until spring 2011.

This revised catalogue includes updates since the September 2009 version. The ISO will seek written comments from stakeholders to ensure that all potential market design enhancements are captured and post a final version in early October.

In 2009, the scope of the catalogue was reconsidered to focus solely on market design initiatives. "Market design" can be described to include policy changes and enhancements rather than process improvements or administrative type changes. In the past, the catalogue contained some topics that while important and timely to stakeholders and staff, were not necessarily related to market design. The purpose of the revisions to the catalogue and ranking process is to evaluate potential changes to existing market design policy enhancements while keeping process and finance related initiatives separate. Hence, we do not include initiatives related to grid management charges, payment acceleration and credit limits.

The first 4 sections after this introduction (sections 2 through 5) describe initiatives related to the various ISO markets (day ahead, hour ahead, real time and residual unit commitment). This is followed by sections 6 and 7 related to certain categories of products (ancillary services and congestion revenue rights). The next two sections describe initiatives related to regional topics (resource adequacy and seams issues). Section 10 contains the miscellaneous market design initiatives that do not clearly fall into any of the other sections. Finally, the catalogue concludes with a Section 11 which holds the market design initiatives that have been completed and Section 12 lists initiatives that have been deleted.

Consistent with the 2009 catalogue, each initiative has been identified with a letter code signifying the status of the initiative. These codes are found next to the title of each item. The key to the codes are as follows:

D - Discretionary or "rankable" Items

F - FERC Mandated Items

I - In-Progress/Planned Items

N - Non Discretionary Items

As a convenience these designations are also listed on the footer of each page.

1.1 The Market Design Initiative Ranking Process

The ISO will not conduct the ranking process for 2010 but will resume that process in summer 2011. The ISO will seek written comments from stakeholders on this revised document to ensure that all potential market design enhancements are captured. The ISO will then publish the final 2010 Catalogue.

For initiatives which were ranked in 2009 we have highlighted the prior rank. The ranking process that was used to prioritize the initiatives in 2009 is documented in the process flow in Figure B. The ranking process involves two steps:

High Level Prioritization

The CAISO first conducted a high level assessment of proposed market initiatives in the Market Design Initiatives Catalogue by applying a simplified ranking process of three benefit and two feasibility criteria based on stakeholder input. In this iteration of the ranking process, each initiative will be graded “High”, “Medium” or “Low” based on the results of their criteria ranking. The high level benefit criteria are “Grid Reliability”, “Improving Market Efficiency”, and “Desired by Stakeholders” as shown in Figure A below. The high level feasibility criteria utilize two measures: “Market Participant Implementation Impact” and “CAISO Implementation impact”.

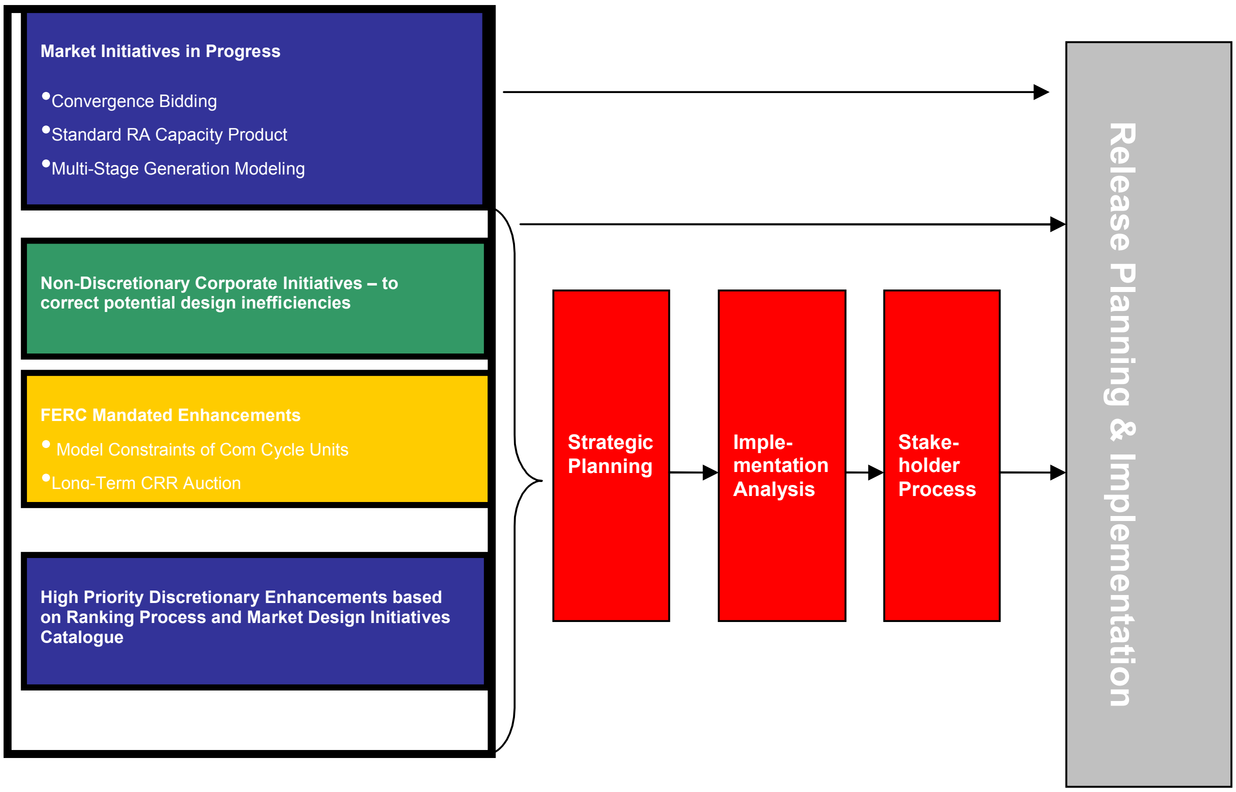
Figure A - CAISO HIGH LEVEL PRIORITIZATION CRITERIA

#		Criteria	HIGH	MEDIUM	LOW	NONE
			10	7	3	0
1	Benefit	Grid Reliability	Significant Improvement	Moderate Improvement	Minimal Improvement	No Improvement
2		Improving Overall Market Efficiency	Significant improvement	Moderate improvement	Minimal improvement	No impact
3		Desired by Stakeholders	Universally desired by stakeholders	Desired by majority of stakeholders	Desired by a small subset of stakeholders	No apparent desire
4	Feasibility	Market Participant Implementation Impact ($ and resources)	No Impact	Minimal Impact	Moderate Impact	Significant impact
5		ISO Implementation Impact ($ and resources)	No Impact	Minimal Impact	Moderate Impact	Significant impact

1.2 Markets and Performance (MAP) Releases

This catalogue is designed to capture design elements that could potentially be implemented to enhance ISO markets. It is important to keep in mind that there are initiatives which have completed the design phase that are now scheduled for testing and implementation.

Figure B – Updated Market Initiatives Roadmap Process



2. Day Ahead Market Design

Since the start of the redesigned CAISO markets, the Day-Ahead Market (DAM) has been operating well, laying the foundation for a series of planned and optional market enhancements that are expected to further improve day-ahead price signals as well as the convergence of day-ahead and real-time market prices. The structure and rules for the DAM are presented in the Business Manuals for Market Operations and Market Instruments.[1]

2.1 Two-Tier rather than single-tier Real Time Bid Cost Recovery (BCR) Allocation (F)

The existing real time BCR cost allocation for new market consists of a single tier charge that is allocated to Measured Demand. In the September 21 Order, FERC ordered the ISO to file tariff language reflecting such an approach. Stakeholders raised concerns regarding the single tier approach and have requested that the ISO implement a two tier charge similar to day ahead Bid Cost Recovery where the first tier would allocate costs based on cost causation principles.

In the FERC April 20th Order the ISO was directed to work with stakeholders to develop a proposal for two-tiered allocation of real-time bid cost recovery costs that could be included within three years after the new market launch.

Throughout the convergence bidding stakeholder process this issue has been raised as a significant issue that a number of stakeholders desire to be resolved concurrently with the implementation of convergence bidding. The issue was also prioritized as high by certain stakeholders during the MAP scoping stakeholder process.

An issue paper was published in October 2008 that outlined some ideas for creating a two-tier structure for real time Bid Cost Recovery. This issue paper was discussed at a convergence bidding stakeholder meeting held in November 2008. The ISO resumed discussions on this topic at the July 2009 convergence bidding stakeholder meeting. The issue paper is posted on the ISO website at http://www.caiso.com/205b/205bf1653cf60.pdf.

2009 Rank: Medium

Status: This enhancement was determined to be out of scope for convergence bidding and will be addressed through a separate stakeholder process. No modifications were included in the Convergence Bidding design approved by the Board of Governors in October 2009.

2.2 Multi-Day Unit Commitment in the IFM (D)

Currently, the forward looking time horizon in IFM is one day, taking into account the impact of prior commitment of units with very long start up times. During the MRTU Stakeholder meetings there were requests that the ISO make commitment decisions in the IFM that look out two to three days in order to create a commitment decision that is more efficient and better reflects the impact of startup-up cost for resources that have long start-up times. There are several design issues, including the need for bidding and bid replication rules as well as software performance and solution time requirements that must be discussed and resolved via a stakeholder process before considering modification of the software to accommodate Multi-Day unit commitment in IFM.

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[1] BPMs are posted on the ISO website and can be found at the following location: http://www.caiso.com/17ba/17baa8bc1ce20.html

As the ISO completed its design for new market, the ISO found that there is an opportunity to run an optimization process, "Extremely Long-Start Commitment" (ELC), following the Residual Unit Commitment (RUC) process. The RUC process is able to consider unit commitment to meet the ISO's forecasted demand for generators with up to 18-hour start-up times, but there are a small number of generators with start-up times exceeding 18 hours. The ELC process gives the ISO the opportunity to determine when it should commit these generators, for reliability purposes, by using a 48-hour optimization period. Further details of the ELC process are available in section 6.8 of the BPM for Market Operations, at:

https://bpm.caiso.com/bpm/bpm/version/000000000000005

There may be limitations on the economic optimality that can be achieved by using separate ELC, RUC, and IFM processes, but these may be unavoidable due to assumptions that bids submitted to the day-ahead market will be applicable on the following day.

PG&E recently requested that "Initial Conditions Management" be added to the catalogue. The ISO believes that the Multi-Day Unit Commitment initiative can be expanded to address these concerns.

2009 Rank: High

Status: The ISO is currently running the 72-Hour Residual Unit Commitment initiative which is an interim step that will provide some benefits until the full multi-day unit commitment solution can be implemented.. Additional documentation can be found at http://www.caiso.com/27ae/27aebe3060d40.html. The proposed changes are scheduled to be presented to the Board of Governors in Nobember.

2.3 Initial Conditions Management (D)

The California ISO Integrated Forward Market (IFM) optimizes unit commitments over a 24 hour time horizon. Would the IFM optimize over a multi-day time horizon, generating units may become economical optimal to remain on-line through the over-night hours to be available for the next day's on-peak energy hours. Under the current design, such generating units may be de-committed in the late hours of the 24-hour time horizon being blind to the next day's opportunities.

The IFM is performed each day after the at 10:00 market close for the next Trade Day (TD), and uses the previous day's (TD-1) Day Ahead Market (DAM) end of time horizon resource commitment pattern for the initial conditions for the next day IFM time horizon optimization. Thus, any resource that is de-committed in the late hours of TD-1 DAM solution is assigned an off-line status for the beginning of the next day's IFM run. In the unit commitment optimization in IFM for TD, the off-line resource must satisfy its minimum down time (MDT) constraint before being re-committed on-line.

The consequence of this behavior is that resources with mid-range MDT parameters, in the 4 to 12 hour range, that economically participating in the DAM may be frequently de-committed in the end of the DAM time horizon and thus have limited ability to economically participate in the next day DAM due to the MDT constraint, even if the resource self commits in the Real Time Market (RTM) to "bridge" the commitment hours in the first 24-hour time horizon.

While the ISO continues to evaluate workable multi-day DAM optimization time horizon concepts, this proposal offers a potential solution to this consequence, under some conditions. The proposal is to have the IFM initial conditions processor first evaluate which resources are de-committed before the end of the 24-hour time horizon, then search SIBR system for any RTM self schedules submitted for the remaining hours of the previous day's DAM time horizon, and if the RTM self schedules bridge the commitment period from the previous day's DAM, then the initial conditions for that resource will be set to on-line for the next day's IFM.

2009 Rank: Not ranked. This is new for the 2010 Catalogue

Status: The proposed solution was discussed with stakeholders at the June 8, 2010 Market Performance and Planning Forum. The whitepaper is available at http://www.caiso.com/27ab/27abd1ed37660.pdf.

2.4 Pricing of Minimum Online Constraints (MOC)

Starting February 5, 2010, the ISO began enforcing the G-217 and G-219 operating procedures in the day-ahead market using a newly created market model variable referred to as a minimum online commitment constraint (or MOC). The operating procedures provide minimum capacity commitment requirements of predetermined localized generators used in mitigating potential thermal overloads and voltage issues in SCE's service area. These operating procedures specify the minimum amount of capacity required to be committed, based on the load levels in the area, to maintain reliability on the local system

The MOC is enforced in all day-ahead market passes (market power mitigation, integrated forward market, and residual unit commitment). This allows energy and ancillary services to be settled consistently across each day-ahead market pass with each pass utilizing the same set of constraints.

The issue is whether or not to pursue a method to price minimum load capacity/energy in the market. A potential long-term term approach may be Convex Hull pricing; however, it may be worthwhile to discuss possible interim solutions.

2009 Rank: Not ranked. This is new for the 2010 Catalogue

Status: None.

2.5 Dynamic Pivotal Supplier Test for Market Power Mitigation (D)

Local Market Power Mitigation in the new market is accomplished through prior classification of transmission constraints as "competitive" or "non-competitive". The question here is whether this process should (or could) be replaced by "on-the-fly" determination of pivotal suppliers in the market-clearing process.

2009 Rank: Medium

Status: None

2.6 Enhancements to Local Market Power Mitigation (F)

The purpose of this initiative to consider what changes should be made to the design of the LMPM provisions to accommodate FERC's order to include bid-in demand into the Pre-IFM process. Another goal of this effort is to resolve the issue of how to incorporate virtual bids and demand response, which are not mitigated, into this process.

2009 Rank: Not ranked. This is new for the 2010 catalogue.

Status: This initiative begins in September 2010.

2.7 Bid Cost Recovery (BCR) for Units Running over Multiple Operating Days (F)

Currently, eligibility for BCR is determined for each operating day. Within each operating day, the revenue received for a unit net of start-up and minimum load costs is evaluated. If this net revenue value is negative, the unit is eligible for BCR for that operating day. This does not adequately consider instances in which a unit's run time crosses over from one operating day into the next. Because the BCR calculation does not determine eligibility based on the entire run time of the unit, but rather evaluates each operating day individually, it is likely that eligibility for BCR is inflated. Market participants therefore bear higher uplift charges. This initiative aims to institute a change to the BCR calculation to reflect the true net revenue of units with run times that cross operating days.

In FERC's September 21 Order (paragraph 533) the ISO was directed to "develop and file with the Commission a plan for units facing these types of constraints for implementation no later than MRTU Release 2". This will likely be addressed as part of the multi-day unit commitment stakeholder process.

2009 Rank: High

Status: In order to assess the magnitude of the issue, the ISO will use data from the first year of new market operation. Specifically, the ISO will analyze the frequency with which units operating over more than one operating day are eligible for BCR in one or both days but wouldn't be eligible if their entire run time were considered thus netting the operating days against one another.

2.8 Treatment of Use-Limited Resources with Limited Number of Hours or Start Ups (D)

Use-limited resources accommodated in the new market are those with Energy (MWh) limitations. This issue would explore how to incorporate software capability to accommodate other types of use limitation, including limitation on the number of hours of usage, or the number of start-ups a resource may be used for, during the scheduling horizon. Such an evaluation would also consider whether alternatives exist for this type of functionality, since the combination of start-up time, minimum run time, and minimum down time will inherently limit the number of start-ups for a resource during a day, and the incurrence of start-up costs can cause the market optimization to minimize the number of start-ups per day.

2009 Rank: Medium

Status: None

2.9 Load Aggregation Point (LAP) Granularity (F)

FERC's 9/21/06 Order on MRTU found that the ISO's approach to calculating and settling energy charges for load based upon three LAP zones provides a reasonable and simplified approach for introducing LMP pricing, while minimizing its impact on load. The Order recognized that some areas could experience higher prices under a nodal model, thus making it desirable to soften the distributional impacts of LMP, and also recognized that LMP could create an economic hardship on entities located in load pockets. Accordingly, FERC approved the ISO's proposal of three major LAP zones as an acceptable starting point. However, the Order directs the ISO (Paragraph 611) to increase the number of LAP zones within three years after the launch of the new market, to provide more accurate price signals and assist participants in the hedging of congestion charges.

FERC's 9/21/06 MRTU Order (Paragraph 614) noted that previous guidance orders had asked the ISO to consider an eventual move to nodal pricing for load, and directed the ISO to move to nodal pricing for load in the future.

FERC's 4/20/07 MRTU Order (Paragraphs 314-331) FERC further directed the ISO to increase the number of LAP zones within three years after MRTU launch.

In 2008 this initiative was ranked low, but in the 2009 ranking it moved up to high in part because of the FERC directive as well as the impact on the implementation of Demand Response. The current LAP configuration inhibits the correct incentives due to the fact that these resources will be buying at the LAP and selling at the node. Further information regarding this issue can be found in the Market Surveillance Committee (MSC) opinion on this issue in "The California ISO's Proxy Demand Response (PDR) Proposal[2] published on May 1, 2009 and "Comments on Barriers to Demand Response and the Symmetric Treatment of Supply and Demand Resources"[3] published on June 30, 2009.

2009 Rank: High

Status: The stakeholder process for this initiative began in August 2010. Additional documentation is available at http://www.caiso.com/27ee/27eed29260a10.html.

2.10 Marginal Loss Hedging Products (D)

Marginal transmission losses can be a significant cost and cost uncertainty for SCs under MRTU. The ISO should investigate the feasibility of developing mechanisms or product(s) for hedging uncertainties with respect to the magnitude of marginal transmission losses.

This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

2009 Rank: Low

Status: None

2.11 Study of Marginal Loss Surplus Allocation to Regional Measured Demand (I)

In the June 2, 2006 Answer to Reply Comments on the MRTU Tariff that was filed on February 9, 2006, the ISO agreed to study the methodology for allocating the over-collection of marginal losses to measured demand on a regional basis, using available LMP studies. The purpose of this study is to determine a credible range of marginal cost of losses to serve the demand in Northern California (NP15 plus ZP 26) and Southern California (SP15), and a commensurate range of actual cost of losses in each region. A credible range of marginal loss surplus (MLS) rebate rate ($/MWh of Demand) for each of the two regions can then be determined and compared with system-wide marginal loss surplus rebate rate. If the system-wide MLS rebate rate falls outside the credible range of the regional MLS rebate rates beyond an acceptable margin, a process for allocation of MLS based on Regional Measured Demand may then have to be worked out; in that case the exact methodology for Regional-based MLS allocation to Measured Demand will be carried out through a stakeholder process. A White Paper on the framework for this study is located at:

http://www.caiso.com/1831/1831d9532fd30.pdf

[2] http://www.caiso.com/241e/241eb5ba44d2.pdf
[3] http://www.caiso.com/23de/23dea1db21b0.pdf

An interim simplified study was performed using 5 months of available LMP data (May through September 2004) with LMP decomposition based on distributed slack. A white paper is located at

http://www.caiso.com/184f/184f8ad86b730.pdf

In the September 21, 2006 MRTU Order, FERC accepted ISO's system-wide Marginal Loss Surplus allocation method as filed, but PG&E filed for rehearing requesting completion of the Marginal Loss study. In its answer, ISO agreed to complete the study using 12 months of LMP data (May 2004 through April 2005), and relaxing the shortcuts used in the interim study. The ISO has completed this study, and the resulting report is available at:

http://www.caiso.com/1bbf/1bbfd56174f50.pdf

2009 Rank: Not Ranked

Status: The conclusion of the ISO's study was that no change in its filed allocation method or the software was needed at market launch. The ISO will monitor the actual allocation results using the same study methodology to determine if a change in its filed method and/or software might be appropriate based on the actual market results.

Additional documents related to this issue are located at:

http://www.caiso.com/docs/2004/11/19/2004111912470915456.html

3. Hour-Ahead Market Design

The Hour-Ahead Scheduling Process (HASP) contains provisions to issue hourly pre-dispatch instructions to System Resources that submit energy bids in the real time market and for the procurement of A/S from those resources. For more details regarding HASP refer to the BPM for Market Operations.[4]

3.1 Creation of a Full Hour-Ahead Settlement Market (D)

This issue is whether to augment the two-settlement market design of MRTU with a third Hour Ahead settlement market, which could be either a substitute for or in addition to the Hour Ahead Scheduling Process (HASP) element of the MRTU design.

2009 Rank: Low

Status: None

4. Real Time Market Design

The Real Time Market consists of the Real Time Unit Commitment (RTUC), Short Term Unit Commitment (STUC) and the Real Time Dispatch (RTD). For more details regarding the Real Time Market refer to the BPM for Market Operations.[5]

4.1 Reliability Demand Response Product (I, N)

The Reliability Demand Response Product (RDRP) is a wholesale demand response product that enables compatibility with, and integration of, existing retail emergency-triggered demand

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4 BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html
5 Ibid.

response programs into the California ISO market and operations, including newly configured demand response resources that have a reliability trigger and desire to be dispatched only under particular system conditions. RDRP development is an outgrowth of an approved settlement agreement before the California Public Utilities Commission to reach agreement on future megawatt quantity limitations of emergency-triggered demand response programs that count as resource adequacy capacity. The RDRP must enable the integration of three general types of retail demand response programs: 1) Large commercial and industrial customer interruptible load, 2) Small commercial and residential customer air-conditioning cycling programs, 3) Agricultural pumping load curtailments.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: The ISO began the initiative in May 2010. The ISO intends to present the RDRP to its Board of Governors in November 2010 for approval, build the product in 2011, and implement it in 2012. Additional documentation is available at http://www.caiso.com/27ab/27ab6e875c2e0.html.

4.2 Rules to Encourage Dispatchability of Intermittent Resources (D)

Currently, wind resources that participate in the Participating Intermittent Resources Program (PIRP) become ineligible for the PIRP rules for settlement of imbalances if they submit price Bids into the RTM. This can create a disincentive for wind resources to offer Decremental Bids for purposes of efficient congestion management and management of over-generation conditions. In addition, the current DEC Bid floor of $-30/MWh is considered by some wind resources to be insufficient to cover opportunity costs of being dispatched down (such as loss of Production Tax Credits). At the same time, projected increases in wind generation make it more important to provide incentives for such Decremental Bids. CAISO will begin a process in 2009 to evaluate the existing rules and incentives for wind to become more dispatchable, jointly with related design initiatives.

In their comments CalWEA, LSA and AWEA support this initiative and further suggest the following market design changes – a) change the PIRP rule to permit retention of monthly netting of imbalances if real-time decremental energy bids are submitted and b) lower the $-30/MWh decremental energy bid floor.

When the ISO staff performed the preliminary detailed ranking of the high level initiatives, it was determined that Day Ahead Scheduling of Intermittent Resources should be included in this section. Based on comments submitted by stakeholders in 2008, and with the market operating experience to date, CAISO is evaluating how to provide appropriate incentives for day-ahead scheduling by intermittent resources or other entities that could provide proxy schedules or Bids that reflect the impact of intermittent resources on the market. As discussed here, relevant topics may emerge in several different areas of market design. The PIRP program design for the market only requires that intermittent resources submit a schedule into the HASP equal to the Hour Ahead PIRP forecast to qualify for the program. By not having expected intermittent resource energy included in the day ahead IFM, the day ahead market solution is incomplete, adversely influencing day ahead LMP, congestion and RUC awards. As intermittent resources, both solar and wind, become a larger percentage in the California energy supplies, the ISO should take steps to ensure this energy is fully incorporated into the IFM, either by creating incentives for PIRP wind resources to schedule or through convergence bidders that might take day-ahead positions that correspond to expected wind output in real-time.

Other issues to consider are:

- Day-ahead market (DAM) wind scheduling looking at (a) how much wind can be scheduled day ahead, (b) will LMP be calculated based on this value or the ISO's own forecast, and (c) how will DA wind schedules affect RUC decisions.
- The day-ahead ancillary service market changes (e.g., the additional Regulating reserves forecast by the CAISO's 2007 Renewable Integration report)

2009 Rank: High

Status: This initiative will be within the scope of the Renewable Integration: Market and Product Review initiative which began in July 2010.

4.3 Ramp Rate Enhancements (D)

Operational ramp rates are used for scheduling and dispatch in real time. In order to maintain performance of the software within the required solution timing parameters, the number of operational ramp rate segments supported in the new market design is limited to 4 (versus 10 segments initially contemplated). Only 5% of the resources with ramp rates operational ramp-rates defined in the Master File would have ramp rates with more than 4 segments defined. Some participants had concerns about the reduction in the number of ramp rate segments. After actual performance is determined, the ISO can work with its vendor to determine if additional operational ramp rate segments can be supported.

While a separate operating reserve ramp rate is used for procuring the spinning and non-spinning reserves, the operational ramp rate is used for all dispatching of a resource. To the extent the operational ramp rate at a given operating level is less than the Operating Reserve ramp rate, the resource may be subject to A/S "No-Pay" charge for reserves that are not actually available based on the lower operational ramp rate. Modifications to the software would be necessary to more closely align procurement of A/S with energy dispatch from A/S capacity in real-time.

2009 Rank: Low

Status: None

4.4 Consideration of UFE as part of Metered Demand for Cost Allocation (D)

The State Water Project (SWP) in its MRTU filing to FERC requested that UFE be allocated load based costs also. In the filing SWP provided concept of "Gross Demand" incorporating metered demand and UFE that would replace metered demand for the purpose of cost allocation.

FERC did not disagree with the concept but rejected the case because the issue was raised late. A similar request was made by SWP with respect to WECC/NERC cost allocation, FERC accepted SWP's proposal and ordered ISO to file compliance with the provision that metered demand and UFE would be allocated WECC/NERC charges.

2009 Rank: Low

Status: None

4.5 Multiple Scheduling Coordinators (SCs) at a Single Meter (D)

On June 7, 2006, FERC issued an order directing the ISO to address the current prohibition on the use of multiple Scheduling Coordinators at a single meter. On July 12, 2006 the ISO posted a White Paper identifying various options for dealing with this issue, primarily addressing generation. The White Paper is located at: http://www.caiso.com/1832/1832c86e1ade0.pdf

The City of Riverside has commented that full-scale implementation of the capability of multiple SCs in bidding, operation and settlement would be desirable.

SCE suggests the ISO should consider redirecting its limited staff to focus on other issues such as MRTU implementation.

Pursuant to the ISO's compliance filing on September 7, 2006, the FERC noted that at that time there was minimal stakeholder interest for pursuing an immediate software solution for the "Multiple SC at a Single Meter" issue.

More recently, discussions concerning the implementation of enhanced demand response following the launch of the new market have identified a potential role for demand response aggregators who would bid price-responsive demand separately from the initial scheduling of load by load serving entities. Before these could be implemented as separate roles, however, a number of issues about the structure of the retail electricity market would need to be resolved, including responsibility for financial settlements of real-time deviations from schedules and dispatches, and for communication between these entities during the scheduling process. The California Public Utilities Commission has identified these foundational policy issues as part of its development of demand response goals, and the ISO is participating in the formulation of these policies to ensure that they can be readily implemented in the ISO's markets once they are formulated.

2009 Rank: Low

Status: None

4.6 Extend Look Ahead for Real Time Optimization (D)

The current real time market conducts a 5 hour "look ahead" optimization. As a result, during the operation day, the optimization will ignore units that have a start up time longer than 5 hours unless they are already running or committed. The optimization should have a process for looking forward for remainder of the entire day in order to commit units with longer start-up times.

2009 Rank: Medium

Status: None

4.7 Enhanced DEC Market (D)

Currently accepted day ahead energy bids are turned into the equivalent of 'day ahead self schedules' for the purposes for the real-time market. In this proposal if a Scheduling Coordinator does not submit any DEC bids associated with its accepted IFM energy schedule, then economic bids submitted and cleared in the Day Ahead Market would automatically flow into the Real Time Market and would be included with DEC bids that are submitted solely into the Real Time Market. Parties who want to override this default will be able to submit real time bids or self schedules.

2009 Rank: High

Status: None

4.8 Directional Bidding in Real Time Market (D)

NCPA requests CAISO add a new initiative to the Market Design Initiative Catalogue to enhance and expand the structure of Bids submitted by market participants within the Real-Time market to allow market participants to clearly communicate an offer to supply incremental Energy or decremental Energy to the CAISO within its Bid using specific attributes contained within the Bid. Under the current market design a market participant may attempt to offer incremental Energy or decremental Energy to the CAISO in Real-Time by providing a price signal in the form of an Energy Bid Curve, but such offer cannot guarantee that the resulting award from the Real-Time market will be consistent with the direction the market participant desires. As a result, in some instances when a market participant would like to provide incremental Energy to the CAISO in the Real-Time market, volatility in Real-Time prices can result in a market award that may be a dispatch or request to provide decremental energy. This inability for a market participant to clearly communicate to the CAISO its desire to provide either incremental Energy or decremental Energy inhibits participation in the Real-Time market. This is particularly challenging for hydroelectric resources which have specific operational constraints to manage storage requirements. Without the ability to communicate to the CAISO the direction in which the unit can be safely dispatched, the generation facility and public safety can be at risk. NCPA requests that enhancements be made to the Real-Time market Bid structure to provide the ability for market participants to clearly communicate to the CAISO the desire to supply incremental Energy or decremental Energy through the use of a flag or other mechanism. This mechanism will improve Grid Reliability and Market Efficiency by allowing more capacity to actively participate in the Real-Time market.

2009 Rank: Not Ranked

Status: None

5. Residual Unit Commitment (RUC)

The purpose of the RUC process is to assess the resulting gap between the IFM Scheduled Load and the ISO Forecast of ISO demand, and to ensure that sufficient capacity is committed or otherwise be available for dispatch in real time in order to meet the demand forecast for each trading hour of the trading day. For more details regarding RUC refer to the BPM for Market Operations.[6]

5.1 Multi-Hour Block Constraints in RUC (F)

SCE raised a concern that resources may be committed for a time period that is inconsistent with its offer, because RUC does not observe any multi-hour block constraints. "SCE requests that the ISO revise its software to honor multi-hour block constraints in RUC for MAP Release 2." (See SCE Comments on Market Initiatives, July 28, 2006, at:

http://www.caiso.com/1845/18459b7a4f300.pdf)

FERC's 9/21/06 MRTU Order (P 1280) finds SCE's request reasonable that the ISO should honor multi-block constraints as a bidding parameter for system resources in the RUC process, and reiterated the finding that the ISO should examine whether such software changes could be implemented by the launch of the new market, or to implement them as soon as feasible. In its application for rehearing, the ISO pointed out that the purpose of RUC is to procure capacity for potential dispatch in real time, when multi-hour block constraints cannot be enforced, and that

[6] BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html

the cost of implementing SCE's proposal would be significant. FERC granted the ISO's request for rehearing, and changed its order to direct the ISO to implement this feature in a future MAP Release.

2009 Rank: Low

Status: None

5.2 Simultaneous Residual Unit Commitment (RUC) and IFM (D)

In the current MRTU design Residual Unit Commitment (RUC) is performed after completion of the IFM and does not impact day ahead market energy, ancillary services (A/S), and congestion/CRR pricing and settlement. The issue here is whether to perform IFM and RUC simultaneously, and if so, how.

2009 Rank: High

Status: This ISO will begin work on this initiative in 2010.

5.3 Consideration of Non-RA Import Energy in the RUC Process (D)

Early in the 2005 MRTU stakeholder process it was suggested that import energy bids that were not cleared in the IFM could be considered in the RUC optimization by treating such bids in the same manner as the minimum load bids of internal generators that were not committed in the IFM. The question to consider is whether, in light of the treatment of imports in RUC as filed in the MRTU tariff, any additional provisions for considering imports in RUC are needed or appropriate. This issue was raised again in the convergence bidding stakeholder process as a means to provide more import capacity in RUC to replace physical intertie bids that may be displaced by virtual bids clearing the IFM.

2009 Rank: Low

Status: None

5.4 RUC Self-Provision (D)

Because of limited interest by most market participants in RUC self-provision feature as a priority for MRTU, the ISO did not to include this feature for Start up. However, FERC's 9/21/06 MRTU Order (Paragraph 172) directs the ISO to continue to work with market participants on this issue, and to provide reasons for the inclusion or exclusion of RUC self-provision no later than three years after the launch of the new market.

2009 Rank: Low

Status: None

6. Ancillary Services

The ISO procures four types of Ancillary Services (A/S) products -- Regulation Up, Regulation Down, Spinning Reserve, Non-Spinning Reserve -- in the day-ahead and real-time markets. Section 4 of Market Operations BPM describes these Ancillary Services.[7]

[7] [7] BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html

6.1 Ancillary Services Substitution (F)

FERC's 9/21/06 Order on MRTU found it reasonable for the ISO to limit Ancillary Services substitution opportunities to units that are in the appropriate location and whose bids clear in the relevant market, but directs the ISO (Paragraph 303) to address the possibility of added flexibility for substitution of the source of Ancillary Services in future releases of market design enhancements.

In its 4/20/07 Order, FERC reiterated that for MRTU, the Commission accepts the ancillary service substitution proposal, and that there was no basis for reversing the prior determination and for the ISO to address the issue of additional flexibility in future MAP releases.

2009 Rank: Low

Status: None

6.2 Exports of Ancillary Services (F)

Under the new market design there is no formal mechanism or specific process for bidding for exports of A/S, or for scheduling on-demand export of A/S. The optimization does not reserve transmission capacity for this functionality. In the new market, a manual workaround has been provided for entities with on-demand obligation; to the extent transmission capacity is available (or must be reserved according to ETC/TOR rights). This issue would explore how to build the reservation of transmission capacity into the optimization so that market participants who might have an obligation to supply Ancillary Service energy in real-time to neighboring control areas can serve this obligation. FERC's 9/21/06 Order on MRTU (Paragraph 355) directs the ISO to develop software to support exports of ancillary services in the future through stakeholder processes and to propose necessary tariff changes to implement this feature no later than three years after the launch of the new market.

2009 Rank: Low

Status: None

6.3 Multi-Settlement System for Ancillary Services (D)

LECG's February 2005 report stated that the lack of a full multi-settlement system for Ancillary Services that optimizes real-time reserves and settles deviations from day-ahead schedules at real-time prices could raise consumer costs when reserves scheduled in the day ahead market must generate energy in real time as a result of minimum run times, minimum down times or transmission constraints. The new market design calls for procurement of A/S in the day ahead market to meet 100% of forecasted real time needs, and then procures additional A/S incrementally in real time only to the extent that they are needed due to changes in system conditions or demand exceeding the day ahead forecast. Moreover, unless the Operating Reserves are designated as "Contingency Only", their energy will be dispatched economically, and if as a result the Operating Reserves fall below the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) Minimum Operating Reserves Criteria (MORC), ISO will procure additional Operating Reserves in real time. The question to be considered is whether to modify the new market design to create a multi-settlement A/S market as suggested by LECG.

If the ISO implements a multi-settlement system issue this would resolve the issue of Ancillary Services substitution described in Section 6.1 above.

2009 Rank: Medium

Status: None

6.4 Ancillary Service Self-Provision at the Interties (D)

The new market design does not include the self-provision of Ancillary Services from interties. Import A/S can only be bid and must compete with import energy bids for the use of New Firm Use (NFU) transmission capacity. This issue explores whether A/S self provision from the interties can be expanded as a potential MAP release feature.

As the ISO's detailed design of the new market progressed, the ISO considered the prospect that self-provision of A/S can be accommodated for dynamic imports. This prospect may be sufficient for the currently anticipated market needs. This topic may have overlapping issues with the direction in FERC's 9/21/06 Order on MRTU (Paragraph 326) to ensure that all provisions of ancillary services, self-provided or not, are subject to the same regional constraints. To the extent that this topic is considered further, this topic would be combined with section 6.2 (Exports of Ancillary Service) since the underlying issue of reserving capacity is common to both issues.

In an April 20, 2007 FERC Order Western raised concern that its Boulder Canyon Project customers in the ISO Control Area currently self-provide ancillary services from the Project over the intertie and into the ISO Control Area and that the September 2006 Order is unclear as to whether these customers can continue to self-provide ancillary services from Western's Control Area to the ISO Control Area. FERC directed the ISO to work with Western determine whether the ISO's work-around is acceptable to Western and to propose any tariff revisions no later than 180 days prior to the implementation of MRTU.

2009 Rank: Low

Status: The "California Independent System Operator Joint Quarterly Seams Reports for the Fourth Quarter of 2008" indicated that Western's issue has been resolved. It states "To the degree Western has the authority to use power from Boulder Canyon to self-provide Ancillary Services for its Ancillary Service obligations to the CAISO; it is the CAISO's understanding that Southern California Edison may schedule self-provided Ancillary Services on behalf of Western from the Boulder Canyon Project using Existing Transmission Contract rights. Western should ensure that it has secured any necessary statements or agreements from Edison to effect this self-provision of Ancillary Services. For purposes of the CAISO's involvement in this matter, the CAISO confirms that self provision of Ancillary Services at the interties is possible under Existing Transmission contract rights or Transmission Ownership Rights."

6.5 Ability to Designate A/S Contingency Hourly (D)

In the new market design the designation of "Contingency Only" ancillary services is accommodated on a daily basis. This issue would explore provisions for hourly designation of "Contingency Only" A/S.

2009 Rank: Medium

Status: None

6.6 Multi-Segment Ancillary Service Bidding (D)

In the new market, ancillary services bids consist of a single bid segment. In comments leading up to FERC's 9/21/06 Order on MRTU, Powerex requested that multi-segment bidding should be provided for some ancillary services. While FERC did not impose this requirement in the launch of the new market, FERC directed the ISO (Paragraph 341) to file a report, before making its MAP Release 2 filing, addressing the potential benefits of including this element.

2009 Rank: Low

Status: None

6.7 A/S Maximum Capability Operating Limits for Spin and Non Spin (D)

This issue would address the concern that a Generator cannot define the maximum operating level for which Spin or Non-Spin capacity can be provided. Currently the Pmax is considered to be the maximum operating level that Spin and Non-Spin capacity can be provided. This is similar to the ability a Generator has to define a maximum regulating level This issue resulted due to concerns that the CAISO may be accounting for operating reserve capacity that may not be deliverable.

2009 Rank: Medium

Status: None

6.8 Addressing Ramping Capacity Constraints (N)

This issue is a potential solution to ensure that sufficient ramping capability beyond the necessary capability, necessary to follow load, to be able to respond to other volatility in imbalance conditions that is separate and not encumbered as operating reserve or regulation capacity. During the preliminary detailed ranking of the high level initiatives, it was determined that there were additional concerns related to the implementation of new AS products, which should be part of this initiative.

The scope of this initiative was broadened to include accounting for regulation ramping capacity in the power balance equation. This issue was creating market inefficiencies which caused the category of this initiative to change to non-discretionary. The ISO is currently considering how to effectively deal with the ramping issues that are impacting grid and market operations. Once specific issues are identified, they will be added to the catalogue as “discretionary” type initiatives that will be ranked.

2009 Rank: High

Status: None

6.9 Voltage Support Procurement (D)

This issue involves the development of a methodology for competitive procurement of Voltage Support services.

The ISO presented papers on both Voltage Support and Black Start during a stakeholder conference call on June 29, 2006, which are available at:

http://www.caiso.com/181c/181ca4c9731f0.html

These papers concluded that there is a wide variety of procurement and cost allocation methods among markets around the world, and that further studies could consider a range of future options.

2009 Rank: Medium

Status: None

6.10 Black Start Procurement (D)

This issue involves the development of a competitive procurement methodology for Black Start services.

The ISO presented papers on both Voltage Support and Black Start during a stakeholder conference call on June 29, 2006, which are available at:

http://www.caiso.com/181c/181ca4c9731f0.html

These papers concluded that there is a wide variety of procurement and cost allocation methods among markets around the world, and that further studies could consider a range of future options. In its 2009 Order on the revised pricing rules for Exceptional Dispatch, FERC has required that the ISO undertake a stakeholder process to examine potential for market-based procurement of voltage support, in part to reduce the frequency of Exceptional Dispatch.

2009 Rank: Medium

Status: None

6.11 30 Minute Operating Reserve (D)

During the stakeholder process of various market initiatives (CPUC Long Term Resource Adequacy proceeding, Scarcity Pricing) stakeholders have raised the potential benefits of a new ancillary services product to address 30 minute reliability contingencies. Under the current market ancillary services structure, potential contingencies that could be covered by a 30 minute product are addressed using 10 minute ancillary services products which could result in the ISO needing to procure ancillary services on a sub-regional basis in higher amounts than would otherwise be necessary to meet WECC operating reserve requirements. Additionally, if the ISO is unable to procure enough reserves through the market, Exceptional Dispatch would be used. An alternative that has been suggested is to develop a new 30 minute A/S product. In its 2009 Order on the revised pricing rules for Exceptional Dispatch, FERC has required that the ISO examine the need for such a new product to reduce the frequency of Exceptional Dispatch.

2009 Rank: Low

Status: The ISO held a stakeholder process in the Fall of 2008 and determined that the 30 minute product was not justified at that time. The ISO will monitor the results of the new market and reconsider the issue in the future if necessary.

6.12 Regulation Energy Management (D)

Regulation Energy Management enables limited energy storage resources or net-zero hourly energy resources to participate in the Day Ahead Regulation Up and Regulation Down market. Upon FERC approval of the Participation of Non-Generator Resources in Ancillary Services initiative (See Item 11.5.2)

2009 Rank: N/A. This is new for the 2010 Catalogue

Status: The ISO included Regulation Energy Management within the scope of the Renewable Integration: Market and Product Review Initiative.

7. Congestion Revenue Rights

This section describes enhancements to the ISO's rules and systems related to Congestion Revenue Rights (CRRs), including both short-term (i.e., one-year Seasonal and Monthly) CRRs as well as Long Term CRRs. CRRs are both allocated to load serving entities and auctioned to all market participants, and the MRTU Tariff established several distinctions in the CRR release process for CRR Year One compared to subsequent years.

7.1 Economic Methodology to Determine if a Transmission Outage Needs to be Scheduled 30-Days Prior to the Outage Month (I)

Currently the ISO Outage BPM requires that all transmission outages must be scheduled with the ISO at least 30-days prior to the month in which they are planned to occur unless they fall under one of the three exemption criteria. However, the tariff currently indicates that only outages that have a significant economic impact need to be scheduled 30-days prior to the month. The ISO needs to develop a process that performs an economic analysis to determine if a specific outage must be schedule 30-days in advance. Such a process should consider the resulting flows and costs associated with an outage and would exempt outages below a certain cost threshold from the 30-day scheduling rule. It is important for the ISO to develop an outage reporting schedule (minimum of one month's notice) that is adequate to support the revenue adequacy of congestion revenue rights.

This was added to the catalogue based on comments submitted by two market participant in April 11, 2008 comments.

2009 Rank: Not Ranked

Status: The ISO intends to begin this study after data has been gathered under the new market. The ISO would like to have at least a year of market experience before beginning this study.

7.2 Long Term CRR Auction (F)

The ISO's January 29, 2007 compliance filing on Long Term CRRs noted that several parties wanted the ISO to implement an auction process for Long Term CRRs, which the ISO agreed to consider for a future release. FERC's July 6, 2007 Order on CRRs encourages the ISO to initiate the stakeholder process and file tariff language to implement an auction for residual Long Term CRRs in a future release of the new market. The 2008 ranking process demonstrated that this item is considered high priority due to its expected market efficiency benefits and the high level of stakeholder desire for it.

In identifying this item as high priority, the ISO notes that it would be logical to combine it with two other CRR-related items which individually were not ranked high in the 2008 process: (1) multi-period optimization algorithm for Long Term CRRs (section 9.6 below), and (2) flexible term lengths of Long Term CRRs (section 9.5). In addition it would also be logical to include a third item with these other items, namely, sale of CRRs in the CRR auctions (section 9.4, provided below). In the 2008 ranking process, however, that item ranked high by itself and therefore is retained in the present document as a separate item that could be implemented independently of a Long Term CRR auction. If the ISO and the stakeholders decide to move forward with a Long Term CRR auction, then the ability to sell CRRs in the auctions would be included in the scope of that effort if it is not implemented sooner.

The multi-period optimization algorithm, for which the April 15th Roadmap discussion is provided below, was already recognized by the ISO as an important CRR enhancement to enable the Long Term CRR release process to recognize future changes in transmission encumbrances over the horizon of the nominated Long Term CRRs (mainly the expiration of ETCs, CVRs and previously-released Long Term CRRs). The multi-period optimization algorithm will thus enable the ISO to find a more optimal balance between the competing objectives of releasing as many Long Term CRRs to the market as possible while minimizing the risk of CRR revenue inadequacy. In the context of an auction for Long Term CRRs, the multi-period optimization will result in auction prices that more accurately reflect the expected values of the Long Term CRRs being awarded. The ISO therefore believes that the multi-period optimization algorithm is an essential component of a Long Term CRR auction.

With regard to flexible term lengths for Long Term CRRs (see Section 9.6 below), the implementation of the multi-period optimization algorithm will make it possible to allow additional choices by market participants beyond the current single 10-year term provided under the existing rules. The exact nature of the allowable choices will be a topic for discussion with stakeholders as the policy and design of this item are developed.

2009 Rank: Medium

Status: None

7.2.1 Flexible Term Lengths of Long Term CRRs (D)

FERC's July 6, 2007 Order on CRRs encourages the ISO to consider future flexibility to allow: (i) Long Term CRRs in excess of 10 years, or (ii) annual CRRs with guaranteed renewal rights up to year 10, or (iii) Long Term CRRs with terms ranging from 2 to 9 years. FERC notes that any subsequent change in the available term lengths would have to respect the rights of the holders of any outstanding 10-year CRRs.

2009 Rank: Medium

Status: None

7.2.2 Multi-period Optimization Algorithm for Long Term CRRs (D)

When the ISO performs the initial release of Long Term CRRs for the period 2008-2017, the Simultaneous Feasibility Test (SFT) optimization will treat the entire 10-year time horizon as a single time period (for each combination of Season and Time of Use period) with respect to network model assumptions. The ISO has recognized that a multi-period algorithm can result in a more optimal allocation of Long Term CRRs because it would be able to reflect different assumptions for each year regarding the availability of grid capacity for CRRs, in particular the known expiration of previously released Long Term CRRs, Existing Transmission Contracts and Converted Rights. FERC's July 6 Order affirms that if the ISO and its stakeholders choose to implement the multi-period algorithm, the ISO must make a compliance filing within 30 days explaining the reasons for the change, how the change will affect Long Term CRR nominations, and how the change has been tested. The ISO had planned to develop this functionality in time for the CRR Year Two release process, but is now deferring implementation of this feature beyond CRR Year 2.

2009 Rank: Medium

Status: Although theoretically "Flexible Term Lengths of Long Term CRRS" and "Multi-period Optimization Algorithm for Long Term CRRS" can be implemented separately, it makes sense to bundle them together, as we have done in this version of the catalogue. They will be ranked as one item.

7.3 Release of CRR Options (D)

FERC's July 6, 2007 Order on CRRs urges the ISO to continue exploring the feasibility of implementing option CRRs in a subsequent market release.

2009 Rank: Medium

Status: None

7.4 Transition to Auction Revenue Rights System (D)

The initial design of the Congestion Revenue Rights release process, as developed through an extensive stakeholder process during 2005, consists of a process for allocating CRRs to eligible Load Serving Entities, followed by an auction process that enables all creditworthy parties to obtain CRRs both for managing their congestion cost exposure and for speculative purposes. An alternative approach that was considered but rejected during the 2005 design process would be not to allocate CRRs directly to eligible LSEs, but instead to release all available CRRs through an auction process and to allocate shares of the net auction revenues to those LSEs that would otherwise have been eligible for CRR allocation. At the time it was recognized that such an “Auction Revenue Rights” or “ARR” approach to CRR release would offer considerable administrative simplification to the CRR program (to effect transfers of CRRs to reflect direct access load migration, for example), would provide maximum flexibility to all CRR Holders to restructure their CRR portfolios to best meet their business needs, and would ensure deep and liquid CRR auction markets for efficient pricing of all CRRs (important for setting CRR credit requirements, for example). Indeed, for the same reasons the eastern ISOs that started with direct allocation of financial transmission rights to LSEs have since converted to ARR systems. Although the dominant preference among ISO stakeholders was to start the LMP markets with a system of direct allocation of CRRs to eligible LSEs, the ISO understood that this design decision was not necessarily intended as the permanent approach for releasing CRRs. Once participants have gained some practical operating experience with CRRs and with the LMP markets in general, the ISO believes it would be valuable to look again at the potential benefits of an ARR system and consider transitioning to such a system. The ISO further suggests that this initiative could be undertaken in conjunction with the initiative to develop an auction process for releasing Long Term CRRs, which FERC has directed the ISO to consider in the MAP Release 2 time frame and is identified elsewhere in this section of the Roadmap.

2009 Rank: Medium

Status: None

7.5 Address CRR Proliferation of Existing Load Migration Process (D)

The current process of generating counter flow CRRs to reflect load migration has increased exponentially the number of CRRs which must be tracked. The ISO has concerns that the tracking of large numbers of small MW CRRs could result in system performance and data management issues.

2009 Rank: N/A. This is new for the 2010 Catalogue.

Status: None

7.6 OTC Methodology to Ensure Revenue Adequacy of Annual Allocation Process (D)

Prior to the 2011 Annual Allocation process, the ISO proposed a new methodology for determining intertie capacity for use in the SFT. The proposal was to select an OTC value which would have resulted in revenue adequacy during the prior year. The proposed methodology would have reduced the number of CRRs allocated versus the existing method of using 100% of the OTC duration curve. Market participants believed that the proposed change was not within existing tariff authority and as such would require a stakeholder process which could not be completed prior to the 2011 Annual Allocation.

2009 Rank: N/A. This is new for the 2010 Catalogue

Status: None

8. Resource/Supply Adequacy Initiatives

The broad area of Supply Adequacy includes primarily activities in which the ISO is a participant but does not play a lead role, although in most activities the ISO does have very specific and essential roles and responsibilities. In addition most – but not all – of the initiatives included in this area fall under state or local regulatory jurisdiction rather than under FERC jurisdiction.

The larger share of activities that will ultimately support Long Term System Security are being conducted under the procedural umbrella of the CPUC's Long Term Procurement Plan (LTPP) Rulemaking. This CPUC rulemaking includes the Phase 1 and Phase 2 Resource Adequacy proceedings as well as several more narrowly focused activities such as the Demand Response proceeding, all of which are discussed in the next four sub-sections, the first of which provides an overview of the entire Long Term Procurement Plan Rulemaking. The final two sub-sections describe Long Term System Security initiatives that are closely inter-related with the CPUC's LTPP Rulemaking but are led by the ISO.

The nature of the Long Term Resource Adequacy Framework will depend critically on the outcome of the CPUC's decision regarding this initiative. For example, if the CPUC decides to adopt a Centralized Capacity Market (CCM) with a primary auction 4-5 years forward of the delivery year, the ISO would expect to conduct a stakeholder process to develop the details of the CCM design and associated tariff provisions. Alternatively, if the CPUC decides to retain today's purely bilateral RA procurement framework, the ISO would need to develop a permanent backstop capacity procurement mechanism.

With the start-up of MRTU, the ISO will implement the Interim Capacity Pricing Mechanism (ICPM) to be used as a backstop capacity procurement device. The ICPM will allow the ISO to backstop or supplement the RA procurement of LSEs if necessary to ensure that there is sufficient generation capacity available to the ISO operators to maintain reliable grid operations. The ICPM is scheduled to sunset on December 31, 2010, at which time another backstop capacity mechanism will be needed as a replacement.

On December 15 2006, the CPUC issued a scoping memorandum that stated that the question of whether to implement a Capacity Market as a central element of its LTRA framework would be included in this proceeding, and a decision on this was scheduled for May, 2008. Most recently the May, 2008 decision has been deferred to an as-yet unspecified date.

The CPUC staff published its "Staff Recommendations on Capacity Market Structure: A Report on the August 2007 Workshops in Collaboration with the ISO" on January 18, 2008. Comments were filed in February 2008 and Reply Comments were submitted in March, 2008. In its comments the ISO recommended a Central Capacity market with a multi-year forward assessment of capacity needs (to be performed collaboratively by CPUC, CEC and ISO), a multi-year forward primary auction, followed by periodic reconfiguration auctions leading up to each delivery year. All Information related to the Long Term Resource Adequacy proceeding can be found on the ISO website at the following link:

http://caiso.com/1b7f/1b7fd6ebe740.html

Ultimately the ISO will need to conduct a stakeholder process which would, at a minimum, develop the replacement for the ICPM when the ICPM sunsets. The specifics of the design of that replacement will of course depend to a large degree on the outcome of the CPUC's decision on the LTRA framework.

8.1 Capacity Procurement Mechanism and Compensation and Bid Mitigation for Exceptional Dispatch (F, N, I)

The ISO is required by FERC to file a successor mechanism to the current Interim Capacity Procurement Mechanism ("ICPM") and updates to the price paid for and the bid mitigation applicable to Exceptional Dispatch at least 120 days prior to the March 31, 2011 sunset of the existing provisions. The ICPM was designed to be an interim backstop procurement mechanism with a definite sunset date as noted above. Although the proposed new Capacity Procurement Mechanism(CPM) will retain many features of the ICPM, the ISO is proposing that CPM be a permanent feature of the ISO's market structure, with provisions for updating certain details as needed, such as the price paid for capacity and potentially some of the criteria for selecting the most effective available capacity. One salient commonality between the proposed CPM and the ICPM is that both mechanisms are intended to procure supply capacity that is not already designated as Resource Adequacy ("RA") capacity and that will, upon accepting an ISO CPM designation,have obligations to be available to the ISO for scheduling and dispatch comparable to the obligations on RA capacity. In this sense both the new CPM and the interim mechanism it will replace may be viewed as limited backstop mechanisms that complement and supplement the capacity procured by load-serving entities ("LSEs") under the RA program.

2009 Rank: Not Ranked

Status: This initiative will go to the ISO Board for approval in November 2010. Additional documentation is available at: http://www.caiso.com/27ae/27ae96bd2e00.html

8.2 Forward Capacity Market (D)

The California ISO worked with the California Public Utilities Commission and other stakeholders during the period 2007 through mid-2010 to explore development of a long-term resource adequacy framework. The discussion included consideration of multi-year forward procurement of resource adequacy capacity and potentially a capacity market. The ISO and stakeholders submitted numerous rounds of written comments to the CPUC in response to a proceeding that was established by the CPUC (Rulemaking 05-12-013, filed December 15, 2005, Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program). On June 3, 2010, the CPUC issued a Decision in the long-term resource adequacy proceeding that leaves the current resource adequacy program essentially unchanged (Decision 10-06-018, Decision on Phase 2 – Track 2 Issues: Adoption of a Preferred Policy for Resource Adequacy). Decision 10-06-018, available on the CPUC web site at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118990.htm, did not adopt a multi-year forward procurement nor did it adopt a capacity market.

2009 Rank: Not Ranked

Status: None

8.3 Replacement Requirement for Scheduled Generation Outages (D)

This initiative is to develop ISO tariff provisions requiring resource adequacy (RA) capacity suppliers to provide replacement capacity to the ISO during periods when their committed RA capacity is unavailable due to a scheduled outage. The California Public Utilities Commission (CPUC) currently has a replacement requirement in its RA rules, but it will consider proposals to discontinue this requirement as early as the 2012 RA compliance year. At the request of the CPUC, the ISO will explore putting a comparable replacement requirement in its tariff to ensure that the CPUC rule elimination does not adversely affect the adequacy of available RA capacity to meet ISO operational needs. The CPUC and many stakeholders have expressed a preference that the ISO provisions apply to suppliers rather than load-serving entities, which makes the RA capacity product more easily tradable. The ISO previously considered including a replacement requirement in the ISO tariff as part of the Standard Capacity Product II stakeholder process, but determined this topic was out of the initiative's scope.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: The ISO began this initiative in August 2010. Additional documentation is available at http://www.caiso.com/27f1/27f1da3b56ef0.html.

8.4 Standard Capacity Product Outage Reporting Requirement (F)

The April 30, 2010 Federal Energy Regulatory Commission Order (Docket No. ER10-319-000) requires Eligible Intermittent Resources, such as wind and solar, that have a maximum output capability of 10 megawatts or greater to report outages of 1 MW and greater, effective July 1, 2010. This results in inconsistencies in how Standard Capacity Product non-availability charges and availability payments affect intermittent resources and non-intermittent resources. As part of the June 22, 2010 Standard Capacity Product Phase II tariff amendment filing to FERC, the California ISO proposed to incorporate forced outages of wind and solar resource adequacy resources in the calculation of Standard Capacity Product availability standards and metrics. The ISO initiated this stakeholder process to standardize outage reporting requirements for wind, solar and all other resource adequacy resources for purposes of Standard Capacity Product availability calculations.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: This final proposal for this initiative was posted in September 2010 and will not require ISO Board approval. Additional documentation is available at http://www.caiso.com/27da/27dadd7343e40.html.

8.5 Standard Capacity Product Outage Reporting Exemption for Grandfathered Qualifying Facilities (I)

With the approval of the Standard Capacity Product (SCP) Phase II tariff amendment in August 2010, RA resources whose qualifying capacity is based on historical data's will be subject to the reporting rules associated with SCP beginning in the 2011 RA compliance year. It has come to the ISO's attention that it may not be feasible for scheduling coordinators representing grandfathered Qualifying Facilities (QFs) to supply forced outage information for use in the calculation of the 2012 SCP monthly availability standards. This proposed exemption will not apply to QFs that are not grandfathered, as the current contracting provisions are the limiting factors.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: This initiative begins in September 2010.

8.6 Standard Capacity Product Planned Outage Availability Incentive Review (I)

Currently, SCP resources on planned outage are considered in the calculation of non-availability charges however they are eligible for availability incentive payments. The scope of this initiative is to examine whether resources on planned outage should be exempt from SCP availability incentive payments..

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: This initiative begins in September 2010.

8.7 Standard RA Capacity Product for Demand Response (F)

In its June 26, 2009 Order, FERC allowed the ISO to temporarily exempt (1) resources whose qualifying capacity is based on historical data and (2) demand response from the Standard Capacity Product availability payments and non-availability charges. FERC urged that these exemptions end as soon as possible and to that end the ISO recently completed the SCP II market design effort to end the exemption for the first category of resources listed above. The ISO anticipates beginning a stakeholder process to address SCP for demand response RA resources in the near future.

2009 Rank: Not Ranked. This is a continuation of FERC Ordered implementation of SCP.

Status: None.

9. Seams and Regional Issues

This topic area includes initiatives to improve coordination between the ISO and neighboring control areas, expand markets for import and export of energy and capacity, and support the continuing development of effective energy markets across the western region.

These issues can be tied to the 2009 Five-Year Strategic Plan Update under Sub-Objective 2.2 Develop Well Functioning and Transparent Electricity Markets under section 2.2.C entitled "Establish regional presence and enhance planning coordination (2009-2013)."

9.1 Interchange Transactions after the Real Time Market (D)

This item will explore ways to allow Scheduling Coordinators to schedule bilateral import and export transactions with the ISO after the close of the real time market at T-75 minutes, in situations where the needed import and export transmission capacity is available.

2009 Rank: Medium

Status: A cooperative project among market participants throughout WECC, known as "Joint Initiatives", includes development of common business practices for intra-hour scheduling. The ISO maintains involvement in discussions of the Joint Initiatives, sees its implementation of dynamic transfers (discussed in section 9.3) as supporting the needs of intra-hour scheduling.

In addition, the ISO's implementation of future dynamic transfer agreements will consider use of the Dynamic Scheduling System (DSS) that has been developed as another of the Joint Initiatives, and the ISO maintains active involvement in WECC committees that coordinate market, operational, and planning initiatives throughout the WECC region. Activities of WECC committees that are particularly pertinent to development of the ISO's markets are the Seams Issues Subcommittee, which is developing a proposal for an Efficient Dispatch Toolkit (including an Enhanced Curtailment Calculator and an Energy Imbalance Market), and the Variable Generation Subcommittee.

9.2 Allocation of Intertie Capacity (D)

To address how intertie capacity gets allocated as well as potentially provide more flexibility to how intertie scheduled cuts get allocated, this initiative would consider other means to allocate intertie (scheduling) capacity. One approach to consider is to allocate capacity via OASIS approach separate from the market. Then only if allocated capacity would a participant be able to offer into the market. How pro-rata cuts are made to those allocated intertie capacity could also be considered in this initiative to provide more flexibility for participants to self-manage what individual schedules would be affected as a result of a Real-Time intertie capacity reduction.

2009 Rank: Low

Status: None

9.3 Dynamic Scheduling/Pseudo Ties (Import and Export) for Load and Generation (N, I)

Increasingly, dynamic scheduling and pseudo-tie scheduling arrangements are being proposed and implemented for renewables as well as conventional generation. As different versions of these arrangements are proposed, the impact to the market design needs to be evaluated and recommendations made regarding the implementation of such arrangements.

A dynamic intertie schedule is one that can be dispatched by the ISO on the same 5-minute intervals that apply to generation within the ISO control area, or that have specific arrangements between control areas for other forms of sub-hourly dispatch. In contrast, traditional intertie schedules are hourly schedules, which change between hours using established ramping schedules that are common throughout WECC. As noted in other sections of this document topics have arisen that involve changes in intertie schedules at intervals that are more frequent than traditional hourly interchange schedules.

Pseudo ties are a form of dynamic scheduling. Through Pseudo Tie functionality, the ISO is able to attain control of resources external to its operational jurisdiction for the procurement of its Balancing Authority Area services, including the ability to engage in dynamic transfers of Energy and Ancillary Services, and full participation in the Locational Marginal Pricing-based (LMP) markets. Pseudo ties are currently being conducted only as pilot programs to provide practical experience and aid in the development of formal policy standards and tariff provisions. Tariff provisions need to be developed for both pseudo tie import and export to standardize this service.

2009 Rank: Not Ranked

Status: The ISO began this initiative in November 2009, and published the Revised Draft Final Proposal in August 2010, which completes the development of most proposals within this initiative. The ISO determined in August 2010 that stakeholder discussions of management of requests for dynamic transfers of intermittent resources should resume after completion of technical studies to determine whether limits need to be applied to dynamic transfers of intermittent resources, before bringing the results of this initiative to the Board of Governors. The ISO anticipates completing the technical studies by the end of 2010. The studies will provide needed information to determine the appropriate process to allocate capacity within any intermittent dynamic transfer limit. Additional documentation is available at http://www.caiso.com/2476/24768d0a2efd0.html.

9.4 Include Cost of Ancillary Services in the Dispatch of Non-Firm Imports (D)

This initiative was submitted by Entegra Power during the Market Issues process and referred to the Market Design Catalogue for consideration. Currently, if a market participant enters an offer to import non-firm energy, the system will decide if it is economic entirely based on the energy bid price. This initiative would change the way these bids are considered and take the energy price as a gross price and only consider a participant economic if the net of the LMP and the ancillary liability is above the bid-in price.

2009 Rank: Not Ranked

Status: None

9.5 Import or Export Bid Submissions from Multiple Scheduling Points (D)

This initiative was submitted by Entegra Power during the Market Issues process and referred to the Market Design Catalogue for consideration. The suggestion is a mechanism whereby participants can submit bids at multiple scheduling points and then be subject to an overall maximum that is accepted from among a set of bids.

2009 Rank: Not Ranked

Status: None

10. Other

10.1 Renewable Integration: Market and Product Review (D)

While protecting system reliability, state policy requires the ISO integrate more renewable energy into California's wholesale energy market. Renewable resources operate with inherent output variability, making forecasting an important and challenging consideration. Further, renewables integration requires additional operational capabilities, including additional ramping support and ancillary services and increased ability to manage over-generation conditions. Renewable energy also imposes new operating requirements, such as more frequent starts and stops and cycling of existing generation units. The ISO wholesale markets redesign in 2009, along with additional planned changes for 2010-2011, improve the ISO's ability to optimize the use of existing resources and generate market-driven prices that support investment in renewable resources. The ISO is confident that the system is capable of supporting 20% renewables integration. However, as we move toward 33% RPS we need to examine further market design changes.

This discussion paper initiates a comprehensive, phased process to work with ISO stakeholders to identify and develop potential changes to wholesale market design, including market products and procedures, needed to accommodate the expected substantial increase in production by variable energy resources over the next decade. The ISO seeks stakeholder input to help prioritize such design changes over the coming years, given the schedule for ISO market enhancements that are already planned or underway. The ISO expects that any proposed design changes resulting from this initiative will support efficient spot markets as well.

The following initiatives listed in the 2010 catalogue will be within scope of this larger initiative: Rules to Encourage Dispatchability of Intermittent Resources, Regulation Energy Management.

In addition, the ISO will conduct a holistic review of ancillary services which may incorporate elements of initiatives outlined in Section 6 of the catalogue.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: The ISO began this initiative in July 2010. Additional documentation is available at http://www.caiso.com/27be/27beb7931d800.html.

10.2 Small and Large Generator Interconnection Procedures (D)

The small generator interconnection procedures established the requirements for generators no larger than 20 megawatts to interconnect to the California ISO controlled grid. FERC's Order No. 2006 issued May 12, 2006 required the ISO to standardize the terms and conditions of open-access interconnection service. The ISO recently experienced a significant increase in the number of small generation projects seeking interconnection. This increase revealed issues with the small generator interconnection procedures. The ISO initiated a stakeholder process to address these issues and revise the small generator interconnection procedures. In discussions to revise the procedures, the potential solutions highlighted impacts to the large generator interconnection procedures. The small and large generator interconnection procedures have interdependencies, such that any solution to one procedure impacts the other.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: The ISO began this initiative in April 2010 and will seek Board of Governor approval of the proposed modifications in September 2010. Additional documentation is available at http://www.caiso.com/275e/275ed48c685e0.html.

10.3 Updating ICPM, Exceptional Dispatch Pricing and Bid Mitigation (F)

The California ISO is conducting a stakeholder process to design the Interim Capacity Procurement Mechanism and Exceptional Dispatch replacement tariffs before the current ones expire on March 31, 2011. The ISO will present a proposal to its Board of Governors during the November 2010 Board meeting to comply with a FERC filing deadline of 120 days before the sunset date. The proposal to the Board will likely contain these elements: successor to the ICPM tariff, update of exceptional dispatch pricing, and extension of bid mitigation for Exceptional Dispatch.

2009 Rank: Not Ranked. This is new for the 2010 Catalogue.

Status: The ISO began this initiative in June 2010. Additional documentation is available at http://www.caiso.com/27ae/27ae96bd2e00.html.

10.4 Forward Energy Products (D)

The ISO should consider offering forward energy products, similar to the PX Block Forward. This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

2009 Rank: Low

Status: None

10.5 Sequential Physical Trading Capability (D)

Buyers who receive physical Scheduling Coordinator trades from generation suppliers in the day ahead market should have the ability to trade back the energy to sellers or other eligible Scheduling Coordinators in the Hour Ahead Scheduling Process (HASP) or in the real time (RT) market. Currently the Tariff and new market allows for only financial trades back to the HASP/RT markets.

2009 Rank: Medium

Status: None

10.6 Pumped Storage Generation Plant Modeling (D)

In its comment PG&E suggested that the catalogue contain an initiative devoted to the proper modeling of pumped storage units. This will impact not only their Helms units, but other market participants who use, or are considering the use of, this type of generation.

2009 Rank: Not Ranked

Status: None

10.7 Lossy vs Lossless Shift Factors (N, I)

Since start-up, the ISO has observed instances in which the dispatch software has resorted to relatively ineffective resource adjustments in attempting to relieve transmission constraints that could not be resolved in the scheduling run. In some instances, the cause for such ineffective adjustments could be traced to the fact that the dispatch software was using lossless shift factors to re-dispatch transmission constraints while taking full account of losses in solving the power balance equation. Said another way, there are certain types of constrained system conditions where the use of lossless shift factors causes the dispatch software to adjust resource schedules in ways that appear to be more effective in solving transmission constraints than they really are, and more effective than they would appear to be if lossy shift factors were used in the re-dispatch. Because these types of market conditions can have significant but spurious price impacts in those five-minute dispatch intervals when they do occur, the ISO is considering whether it would be beneficial to market performance to adopt the use of lossy shift factors in the market optimizations.

2009 Rank: Not Ranked

Status: On June 15, 2009 the ISO published a technical bulletin entitled “Comparison of Lossy versus Lossless Shift Factors in the ISO Market Optimizations.”

10.8 Enhanced Inter-SC Trades (D)

PG&E requested that “Enhanced Inter-SC Trades (After-Market Inter-SC Trades)” proposal be added to the Market Design Catalogue. This proposal would make it possible to submit and match Inter-SC Trades (ISTs) after the close of the market, with three possible options at varying levels of implementation difficulty.

First (and simplest), trades at points not currently having matched trades are permitted after the market closes. These would be new trades, hence there are no issues about pre-market trades being cancelled to game the price outcomes. Second, trades are permitted after market close if incremental to existing trades, but existing trades cannot be reduced after market close. Third, identify post-market ISTs as distinct products from pre-market ISTs.

2009 Rank: Low

Status: None

10.9 Data Release and Accessibility Release - Phase 3 (D)

With the start up of the California ISO's new market system based on Locational Marginal Pricing (LMP) on April 1, 2009, stakeholders have expressed a desire for the release of additional information that would enable them to better understand market results and participate more effectively in the ISO markets. In response, the ISO committed to conduct a stakeholder process to explore the issue of data release and accessibility in ISO markets and to implement appropriate enhancements to its current data provision practices. Phase 3 is focused on market data to support well-functioning, competitive ISO spot markets, including Price Discovery and Outage Information. See Section 11 of the Catalogue for information on Phases 1 and 2 of this initiative.

2009 Rank: Not Ranked

Status: The ISO is planning to begin this initiative in early Q4 '10.

11. Completed Initiatives from 2009 Catalogue

This section provides a list of the 2009 initiatives that have either been completed

11.1 Day Ahead Market Design

11.1.1 Convergence Bidding (F, I)

Convergence (or virtual) bidding is a mechanism whereby market participants can make financial sales (or purchases) of energy in the day ahead market, with the explicit requirement to buy back (or sell back) that energy in the real time market, thereby potentially moving the day ahead and real time prices closer together.

FERC's 9/12/06 MRTU Order (P 430-452) required the ISO to implement convergence bidding within 12 months of the launch of the new market. FERC's 4/20/07 Order (P 105-119) specified that the ISO must file tariff language for the implementation of convergence bidding no later than 60 days prior to the one year anniversary of new market (MRTU) launch.

2009 Rank: Not Ranked

Status: The ISO Board of Governors approved the proposed enhancements on October 29, 2009. Tariff language was filed with FERC on June 25, 2010. FERC approval is pending. The enhancements are planned to be implemented in February 2011. Additional documentation is available at http://www.caiso.com/1807/1807996f7020.html#27d8e6d937600.

11.1.2 Day Ahead Market Power Mitigation Based on Bid in Demand (I)

In a 2005 review of MRTU LECG suggested the use of bid-in demand rather than demand forecast in pre- integrated forward market (IFM) passes in the day ahead market. LECG also recommended eliminating use of extreme DEC bids in Pass 2 pre-IFM for schedules selected in the Pass 1, and unrestricting the pool of resources in IFM and RUC based on unit commitment in Pre-IFM.

FERC's 9/21/06 MRTU Order (P 1089) conditionally accepted the ISO's proposal to use forecasted demand in Pre-IFM passes, subject to the ISO instituting bid-in demand as the basis for applying market power mitigation in the pre-IFM runs no later than MAP Release 2 to reduce the likelihood of over-mitigation of suppliers.

As an outcome of the convergence bidding stakeholder process the ISO is proposing that market power mitigation based on bid-in Demand be implemented concurrently with -

convergence bidding in MAP. Since virtual bids may impact the market power of physical bids they should be considered in the day ahead market power mitigation process even though they would not actually be mitigated like physical bids.

2009 Rank: Not Ranked

Status: The ISO Board of Governors approved the proposed enhancements on October 29, 2009 as part of Convergence Bidding. Tariff language was filed with FERC on June 25, 2010. FERC approval is pending. The enhancements are planned to be implemented in February 2011. Additional documentation is available at http://www.caiso.com/1807/1807996f7020.html#27d8e6d937600.

11.1.3 Scarcity Pricing (I)

The current market design provides for scarcity pricing for energy; however, no explicit measures are included for scarcity pricing of reserves. Reserve prices may exceed the bid cap to the extent of the opportunity cost of energy. In other words, Reserve prices will generally be limited to the sum of the prevailing bid cap for Reserves plus the prevailing bid cap for energy. FERC's 9/21/06 MRTU Order (Paragraphs 1077 to 1079) found that the ISO's initial scarcity pricing approach is too narrowly tailored, and that prices should rise to reflect the increased need for reserves and energy, whether or not the shortage arises in conjunction with a generation or transmission outage, in both the day-ahead and real-time markets. While FERC concluded that the ISO's limited scarcity pricing approach is a reasonable start for implementation of the new market, the ISO should further refine its proposal to include a more broadly-triggered reserve shortage scarcity pricing, and on a more accelerated basis, to ensure that prices are not inappropriately suppressed during periods of genuine scarcity. The Order directs the ISO to file tariff language for the implementation of an expanded scarcity pricing methodology within 12 months of the effective date of new market. Furthermore, the Order directs the ISO to develop a reserve shortage scarcity pricing mechanism that applies administratively-determined graduated prices to various levels of reserve shortage, to be implemented within 12 months after MRTU launch.

2009 Rank: Not Ranked

Status: The proposed enhancements were approved by the Board of Governors in December 2009. Tariff language was filed with FERC in December 2010. FERC approval was received in June 2010 subject to a compliance filing. Implementation is planned for December 2010. Additional documentation is available at http://www.caiso.com/2478/2478ac4559c70.html.

11.1.4 Proxy Demand Response (I)

FERC Order 719, which was issued in October of 2008, requires that ISOs permit DR aggregators also known as a Curtailment Service Provider (CSP) to bid demand response on behalf of retail customers into the organized energy markets. In response to the FERC Order 719 requirements as well as the request from market participants for a product that would better accommodate existing Demand Response retail programs; the ISO developed the concept of the PDR product. The proposed PDR product was developed based on feedback from market participants that the Participating Load functionality available at MRTU launch and the proposed refinements to Participating Load did not provide flexibility needed to incorporate price responsive Demand Response programs into the ISO markets. Specifically, the PDR Product addresses the following challenges:

- Allows the Curtailment Service Provider (CSP) to bid Demand Response directly into the ISO's energy and ancillary service markets and to participate separately from the LoadServing Entity (LSE) as required by FERC Order 719

- Allows retail DR programs that are imbedded as part of the Investor-Owned Utility's (IOU) load to participate in the ISO energy and ancillary services markets
- Enables the underlying base load associated with the DR resource or program to be embedded in the LSE's overall load schedule at the Default LAP level, while a separate bid for DR, represented as a proxy generator, will represent the price-responsive demand within a Custom LAP

2009 Rank: Not Ranked

Status: The proposed enhancements were approved by the Board of Governors in September 2009. Tariff language was filed with FERC in February 2010. FERC approved PDR in July 2010. The enhancements were implemented in August 2010. Additional documentation is available at http://www.caiso.com/23bc/23bc873456980.html.

11.1.5 Participating Load Refinements (I)

The existing market software includes limited functionality to allow demand resources to participate directly in the ISO's wholesale markets. Through the implementation of refinemetns to the participating load functionality, ISO will complete the functionality that was intended to be part of the original MRTU market design.

The refinements to be implemented provide a flexible model for Participating Loads that allows a single resource to both schedule demand and bid load curtailments as an integrated bid, which can use co-optimization of Energy and Ancillary Services in both the day ahead and real time markets to determine the best utilization of the demand response resource. The refined functionality will effectively provide demand response resources with full comparable functionality to that of a generator in the ISO's markets. This design provides considerable flexibility for demand response resources, allowing Participating Loads to (1) simply bid into the ISO markets with a forward Energy Bid, (2) provide additional details about the operating characteristics of the demand response resource like Minimum Load Reduction (minimum MW of demand response),Minimum and Maximum Load Reduction Time, and Minimum Load Reduction Cost in addition to the Energy Bid, or (3) provide capacity for Residual Unit Commitment (RUC) and/or as Non- Spinning Reserve or other Ancillary Services (A/S).

The September 21, 2006, FERC Order on MRTU, as well as FERC Orders since then, directed the ISO to work with market participants to present additional opportunities for Demand Response resources to participate in the ISO Markets. The ISO has responded to these orders through the implementation of the participating load refinements as well as through the introduction of Proxy Demand Resource which is described in Section 11.1.4 above.

2009 Rank: Not Ranked

Status: In April 2010, implementation Participating Load Refinements were delayed for the following reasons: (1) Need to implement convergence bidding on its own in February 2011, (2) PLR more complicated and costly to implement than original projections, and (3) Aggregated pumps and aggregated pump storage can be met through future enhancements to the MSG model. The participating load refinements will be implemented in Fall 2011. Additional documentation is available at http://www.caiso.com/23bc/23bc8a516fa20.html.

11.1.6 *Ex Post* Price Correction "Make-Whole" Payments (N)

Ex post price corrections have led to instances in which bids that were cleared in the market are no longer economic when evaluated against the corrected price. Currently, the ISO does not have a policy or mechanism for compensating Market Participants when this occurs. The absence of such a "make-whole" mechanism was based on the assumption that the market results would always be consistent with the cleared bids. In practice, this is generally the case. When market prices require corrections, however, settlement prices can differ from the value of the cleared bids. Through this initiative, the ISO will develop a "make-whole" payment mechanism to compensate Market Participants for adverse financial impacts in the case when prices are adjusted in a way that is not consistent with their accepted bids.

2009 Rank: Not Ranked

Status: The proposed modifications were approved by the Board of Governors in February 2020. FERC approval was received in May 2010. The modifications were implemented in June 2010. Additional documentation is available at http://www.caiso.com/2453/2453ab8e10ff0.html.

11.1.7 Ability to Bid Start Up Costs and Minimum Load Costs and Market Power Mitigation for Start Up and Minimum Load Cost Bids (I)

On July 31, 2009 the ISO filed a tariff amendment with FERC to modify the restriction on the frequency with which a resource owner can modify its election of how to recover Start-Up and Minimum Load Costs from once every six months to once every thirty days and modify the cap on the amount of recoverable Start-Up and Minimum Load Costs under one of the options the resource owner may elect. The intent of this initiative to provide participants with the ability to bid start up and minimum load costs.

There is an additional matter related to start up and minimum load cost related to bid caps. In response to concerns identified as part of the 2006 Market Initiatives Roadmap, the ISO developed bid caps for startup and minimum load bids submitted by generators under the six-month bid-based option for start up and minimum load bids.[8] The proposed caps were designed to be implemented by limiting bids that can be entered in the Master File, so that these caps could be applied as part of the new market design without changes in the actual market software. However, as part of the process of developing these bid caps, there was widespread support among stakeholders, DMM and the MSC for pursing a more dynamic approach under which startup and minimum load bids submitted under the six month bid-based option would be mitigated to default cost-based levels only when a unit was committed to meet a non-competitive transmission constraint.

The more dynamic approach that was discussed as part of this process would closely mirror how energy bids will be mitigated under the new market design, as well as how start up and minimum load bids submitted under the six month bid-based option are mitigated under PJM's market design. Specifically, if a unit was not committed under the Competitive Constraints Run (CCR) of the MPM procedures, but was committed under the All Constraints Run (ACC), the unit's startup and minimum load bids would be subject to mitigation to default cost-based levels. With this approach, it may still be necessary to retain some very high caps on startup and minimum load bids submitted under the six month bid-based option, since these bids would still be in effective.

2009 Rank: High

Status: The proposed enhancements were approved by the Board of Governors in July 2010. Tariff language was filed with FERC in July 2010. FERC approval is pending. The planned

[8] See Five-year Market Initiatives Roadmap, 2008-2012, REVISED DRAFT – April _15_, 2008, Section 2.1.4, p.12

implementation date is October 2010. Additional documentation can be found at http://www.caiso.com/23d9/23d9c75e22ab0.html.

11.1.8 Potential Modifications to Market Rules for Day-Ahead Intertie Schedules (D)

To improve reliable grid operation and clarify market rules, the ISO is considering tariff changes to clarify the timeline for submitting e-tags for imports and exports that are scheduled or accepted in the Integrated Forward Market (IFM).

Under current market rules, market participants may re-bid an import or export in the HASP that originally cleared the IFM. Currently, some import or export bids that clear the IFM are not tagged in the day-ahead timeframe (i.e. by the 3 p.m. deadline under WECC e-tagging guidelines). In these cases, it appears that some market participants only procure the resources to deliver on a bid and submit an e-tag in the event the bid also clears the HASP. Alternatively, if an import or export that originally cleared the IFM does not clear again in the HASP, the market participant essentially "buys-back" the import (or "sells-back" an export) at the HASP price.

The ISO is concerned that waiting until after the HASP to procure resources to deliver on day-ahead imports or exports has the potential to cause operational problems when supplies are tight. In this case, by the time a day-ahead import also clears the HASP, the market participant may not be able to find the resources (energy plus transmission) to deliver the import (alternatively, may not be able to deliver an export during over-generation). In especially tight supply periods, when the CAISO is relying on imports to meet its load obligations, internal load has priority in the HASP over bids to buy-back imports, virtually assuring that day-ahead imports will clear again in the HASP.

The lack of clarity about the timeline for tagging imports and exports that clear the IFM market also results in an asymmetry, where some market participants arrange resources for IFM import and export schedules and submit e-tags in the day-ahead timeframe, while other participants wait until after the HASP. This may place participants who arrange resources necessary to ensure that IFM schedules can be met at a competitive disadvantage relative to participants who wait until after the HASP to make arrangements to met final import and export schedules.

The ISO has identified several potential market rule changes that might address this issue, which include (1) requiring e-tags to accompany IFM import or export bids, (2) requiring imports or exports awarded in the IFM to be tagged in the day-ahead timeframe, or (3) requiring that an e-tag be submitted prior to the HASP for an import or export to be bought back at the HASP price and/or (4) establishing a penalty charge for imports or exports not tagged prior to the HASP.

2009 Rank: High

Status: The proposed changes were approved by the Board of Governors if February 2010. Tariff language was incorporated in to the Convergence Bidding filing. FERC approval is pending. Implementation is planned for February 2011. Additional documentation can be found at http://www.caiso.com/244c/244cabfb36550.html.

11.1.9 Consider Modifying the Rules Designating the Supply Pool in the IFM (N, I)

The current market design includes a mechanism in the Integrated Forward Market (IFM) for local market power mitigation. In the pre-IFM Local Market Power Mitigation process, the IFM market model is first run with only Competitive Constraints enforced. A second run of the model is then performed with All Constraints enforced. Supply resources that are dispatched to a higher level in this second All Constraints run are then subject to bid mitigation. These pre-IFM Local Market Power Mitigation runs use the ISO demand forecast rather than bid-in demand.

The supply resources that are dispatched in the Local Market Power Mitigation process are then made available to the IFM for market clearing of supply resources and bid-in demand. Currently, bids from resources that are not dispatched in the Local Market Power Mitigation process are not made available to the IFM. The purpose for this rule is to prevent the potential for high unmitigated supply bids to set market clearing prices in the IFM.

This rule has generally worked as expected. However, this rule has the potential to raise overall costs in the IFM in some situations, especially when the bid-in demand is significantly higher than the ISO demand forecast.

2009 Rank: Not Ranked

Status: The proposed design changes were approved by the Board of Governors in September 2010. FERC order was received in December 2009. Implementation is pending. Additional documentation is available at http://www.caiso.com/23d8/23d8bb9a6ee20.html.

11.2 Hour Ahead Market Design

No 2009 Catalogue initiatives were completed for the Hour Ahead Market.

11.3 Real Time Market Design

11.3.1 Real Time Imbalance Energy Offset (N, I)

On June 24, 2009, the first invoices generated from the new market design, were published and reviewed for settlement implications of the new market model. Based on this review, Scheduling Coordinators and ISO identified that a particular charge group, called the Imbalance Energy Charge Group, had produced some unexpected results. In particular, Scheduling Coordinators were assessed $14.3M for Real-Time Imbalance Energy Offset costs. The ISO will review the drivers of these costs and present a proposal to more accurately assess these costs in line with cost causation.

2009 Rank: Not Ranked

Status: The proposed modifications were approved by the Board of Governors in September 2009. Tariff language was approved by FERC in September 2009. Additional documentation is available at http://www.caiso.com/2406/2406e2a640420.html.

11.4 Residual Unit Commitment (RUC)

No initiatives completed since 2009 catalogue.

11.5 Ancillary Services

11.5.1 Ancillary Services Procurement in HASP and Dispatch Logic (N)

The February 9, 2006 MRTU Tariff filed by the CAISO proposed to procure Ancillary Services from both internal and external resources in the Day-Ahead Market, the Hour Ahead Scheduling Process (HASP), and the Real-Time Market. The HASP is designed to procure additional Ancillary Services needed to meet reliability requirements after the Day-Ahead Market, and to determine the optimal mix of Ancillary Services from internal resources, dynamic system resources, and non-dynamic system resources for the next trading hour. However, the market simulation revealed that software limitations prevented the CAISO from dispatching energy from the operating reserve capacity procured from non-dynamic system resources through HASP. To prepare for the new market launch, the CAISO filed and received approval from FERC to defer the procurement of Ancillary Services in HASP, and to procure any required incremental Ancillary Services after the Day-Ahead Market in the fifteen minute Real-Time Pre-Dispatch (RTPD) process.

2009 Rank: Not Ranked

Status: The proposed enhancements were approved by the Board of Governors in September 2010 and implemented in April 2010. Additional documentation is available at http://www.caiso.com/2401/2401702e12ca0.html.

11.5.2 Non-Generation Resources in Ancillary Services Markets (F)

FERC Order 719 directs RTOs and ISOs to allow demand response resources to participate in Ancillary Service Markets. Specifically, the Commission required each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process if the demand response resources (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally applicable bidding rules at or below the market clearing price[9]. According to the Commission, demand response resources that are technically capable of providing the ancillary service within the response time requirements, and that meet reasonable requirements adopted by the RTO or ISO as to size, telemetry, metering and bidding, must be eligible to bid to supply energy imbalance, spinning reserves, supplemental reserves, reactive and voltage control, and regulation and frequency response[10]. The Commission declined to adopt a standardized set of technical requirements for demand response resources participating in ancillary services markets. Rather, the Commission is allowing each RTO and ISO, in conjunction with its stakeholders, to develop its own minimum requirements[11].

This initiative not only addresses the concerns surrounding demand response resource relative to ancillary service but also storage type resources.

2009 Rank: Not Ranked

Status: The proposed modifications were approved by the Board of Governors in March 2010. The Regulation Energy Management design enhancement was not included in the proposal to the Board and will be address during the Renewable Integration: Market and Product Review Initiative which began in July 2010. Tariff language was filed with FERC in July 2010. FERC approval is pending. Implementation is planned for September 2010. Additional documentation is available at http://www.caiso.com/2415/24157662689a0.html.

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[9] *Id.* at P 47. The Commission exempted circumstances where the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.

[10] *Id.* at P 49.

[11] *Id.* at P 59. The Commission further required RTOs and ISOs to coordinate with each other in the development of such technical requirements, and provide the Commission with a technical and factual basis for any necessary regional variations. The Commission concluded that such coordination should ensure that any developed requirement is not so full of technical detail or so burdensome that it discourages demand response resource participation.

11.6 Congestion Revenue Rights

A stakeholder process was initiated in July 2009 and completed in December 2010 to address several CRR Enhancements, covering:

- CRR credit-related issues: pre-auction credit requirements, process for liquidating the CRRs of a defaulting CRR holder, and credit requirements for extraordinary circumstances,
- Non-Credit Policy Issues: process for adjusting CRR holdings to reflect load migration, method for handling trading hubs in the CRR release, weighted least squares objective function, elimination of multi-point CRRs, and refinement of tiers in monthly CRR allocation, and
- Non-Credit Business Process Issues: sale of CRRs in the CRR auction, modeling to reinforce CRR revenue adequacy, tracking of long-term CRRs in the CRR system, and process for receiving certain data in the priority nomination process.

These topics included both issues that were identified through previous market design initiative rankings and the ISO's experience in running CRR processes to date. Some topics involved tariff changes, which have been approved by FERC orders in August and September 2010, while others have been business process revisions within existing tariff provisions. Subsections below update the previous market design initiative catalogs for issues that were listed therein, and further information about all initiatives is available at http://www.caiso.com/2403/24037c20669e0.html.

11.6.1 Sale of CRRs in the CRR Auctions (F, I)

The CRR systems at present have functionality to allow a party to offer for sale in an ISO CRR auction some of the same CRRs that were previously awarded in an auction or allocation process. The systems do allow the party to engage in a financially equivalent transaction, but this equivalent transaction results in the party holding two equal and opposite CRRs that net out financially, rather than allowing an actual transfer of the original CRR. For example, if the party holds a CRR of 10 MW from source A to sink B and wants to sell that CRR in a ISO auction, under the CRR Year One functionality the party cannot offer to sell that exact CRR, but must offer to buy at a negative price (assuming the original A to B CRR has positive expected value) a CRR of 10 MW from source B to sink A. If this offer clears the auction, the party ends up holding two 10 MW CRRs, one from A to B and another from B to A, and receives payment for the negative auction clearing price of the B to A CRR which should be the same as the price the party would have received for selling the A to B CRR at a positive price.

Of course, the party also has the option of selling the original A to B CRR bilaterally and then registering the bilateral transaction in the ISO's Secondary Registration System, but several parties previously indicated in the stakeholder process that the ability to offer CRR holdings for sale in a ISO auction process would enhance the efficiency of the CRR market. FERC's September 21, 2006 MRTU Order affirmed that it would be useful to have this feature, and the ISO has included this functionality among the enhancements to the CRR systems in the 2009-2010 CRR Enhancements stakeholder process. The September 2006 Order directed the ISO to file tariff language to implement the ability to sell CRRs in the CRR auctions no later than MAP Release 2.

2009 Rank: Not Ranked

Status: In conformance with existing tariff language, the ISO addressed the business process details for selling CRRs through the 2009-2010 CRR Enhancements stakeholder process, and is now implementing these business process changes. Implementation is planned by November 2010. Additional documentation is available at http://www.caiso.com/2403/24037c20669e0.html.

11.6.2 Revised Approach for Releasing and Tracking CRRs having a Trading Hub Source or Sink (D)

The current rules for handling CRR nominations sourced at a Trading Hub in the allocation process use a "disaggregation" approach whereby such nominations are disaggregated or unbundled into individual Point-to-Point CRRs each of which has as its source a Generating Unit PNode that is a constituent of the Trading Hub. Such nominations are then submitted to the optimization and eventually awarded to the nominating LSE in the unbundled form. Two concerns were identified with this approach.

First, although the CRR Sources in the awarded "bundle" are expected to closely resemble the composition of the Trading Hub, the bundle will in general not match the Trading Hub exactly. FERC's July 6 Order directed the ISO to consider whether to develop software to assist LSEs in the trading of Trading Hub CRRs by "rebundling" individual PNode CRRs to reconstitute a Trading Hub CRR. More generally the ISO was also required by the Order to make a compliance filing within 6 months after the launch of the new market that explains whether the disaggregation method remains appropriate.

Second, the disaggregation approach resulted in large numbers of fractional-MW CRRs, due to the fact that a trading hub may be comprised of a few hundred constituent generator PNodes. These fractional-MW CRRs were further broken down into even smaller and more numerous individual point-to-point CRRs through other CRR processes, such as the transfer of CRRs between LSEs to account for migration of direct access load. The result is a population of CRRs whose management was burdensome for CRR holders as well as the ISO.

2009 Rank: Medium

Status: The proposed enhancements were approved by the Board of Governors in May 2010. Tariff language was filed with FERC in July 2010 and approved by FERC on September 1, 2010. Implementation is planned by December 2010. Additional documentation is available at http://www.caiso.com/2403/24037c20669e0.html.

11.6.3 Use of "Weighted Least Squares" CRR Optimization Algorithm (I)

Under the current algorithm, when two or more CRR allocation nominations by different LSEs compete for limited transfer capacity on a binding transmission constraint, the optimization algorithm will try to maximize the amount of CRRs released by reducing the CRR nomination that has highest effectiveness in relieving the constraint. The advantage of this approach is that the total overall MW of CRRs released is maximized. An undesirable side effect, however, is that the reduction in awarded CRRs due to the constraint will typically fall entirely on the one LSE that nominated the most effective CRR. In previous stakeholder discussions this aspect of the optimization algorithm was identified as a feature we could not change for CRR Year One. In the 2009-2010 CRR Enhancements stakeholder process, the ISO discussed utilizing a "weighted least squares" algorithm that would allocate shares of the constrained transmission facility to each CRR nomination that has some effectiveness on the constraint. Although this approach will typically result in fewer total CRRs being allocated, it is considered a more equitable approach to CRR allocation because it distributes the impact of the constraint across all LSEs whose nominations contribute to that constraint.

As a final point, note that the problem described is really only a problem in the CRR allocation processes. In the CRR auction processes the objective of the optimization algorithm is to maximize net auction revenues and therefore the bid prices are also taken into account in any reductions of bid MW to relieve constraints. Auction participants can use their bid prices to express the relative value they place on obtaining CRRs that impact congested transmission facilities.

2009 Rank: Not Ranked

Status: The proposed enhancements were approved by the Board of Governors in May 2010. Tariff language was filed with FERC in July 2010 and approved by FERC on September 1, 2010.. Implementation is planned for December 2010. Additional documentation is available at http://www.caiso.com/2403/24037c20669e0.html.

11.6.4 Revise Load Migration Process (N)

As the ISO's implementation of the process to reflect load migration on CRR ownership is completed, the CAISO is considering the prospect of gaining efficiencies in the production process. Under current design, the ISO carries out the production task in two main steps. In a first step, the percentage of load being transferred between Load Serving Entities (LSEs) is estimated based on data of customer transfers provided by UDCs. In a subsequent step, the transfer of Congestion Revenue Rights is calculated between LSEs using the percentages from the first step as the reference.

Since the original efforts of this initiative, the first step of this process has been highly convoluted due primarily to the need of receiving confidential data owned by UDCs. The current process requires that UDCs submit data in different files following a specific format within a particular timeframe. Since all input data is prepared by UDCs and the design requirements to compute the percentage of load migration have been finalized, ISO explored the alternative of having part of the first step of the process carried out by UDCs. This will eliminate cumbersome steps of uploading and maintaining confidential data by the ISO.

2009 Rank: Not Ranked

Status: The proposed enhancements were approved by the Board of Governors in May 2010. Tariff language was filed with FERC in July 2010 and approved by FERC on September 1, 2010.Implementation is planned for December 2010. Additional documentation is available at http://www.caiso.com/2403/24037c20669e0.html.

11.7 Resource/Supply Adequacy Initiatives

11.7.1 Enhancements to Standard RA Capacity Product (D)

Based on the 2008 Market Initiatives Roadmap process the ISO and stakeholders developed a tariff amendment to implement a standard RA capacity product (SCP) for implementation in the 2010 RA compliance year. This tariff amendment has been substantially approved by FERC and was also included in the CPUC's RA Phase 2 proceeding. In an effort to meet the 2010 compliance year timeframe, some enhancements to the SCP were set aside for future consideration, including generation types that were deferred from the availability metric.

In their comments NRG notes that the ISO has been directed by FERC to work with stakeholders to implement SCP for the deferred types of generation. They also suggest that the ISO should start a stakeholder initiative to consider whether the market is "sufficiently robust enough to warrant the elimination of the exemption from participation in the energy market" by certain classes of generation.

2009 Rank: High

Status: The Standard Capacity Product Phase II was approved by the Board of Governors in May 2010. Additional documentation is available at http://www.caiso.com/2479/2479e7362d1e0.html.

11.7.2 Generating Bids and Outage Reporting for NRS-RA Resources

Suppliers of Resource Adequacy (RA) capacity have the obligation to bid that capacity into the California ISO market. The ISO therefore has Tariff authority to insert generated bids for RA resources that fail to bid into the market. There are gaps in this process, however, when it comes to the case of system (or import) resources that are not resource-specific but do have RA contracts (NRS-RA resources). Through this stakeholder effort, the ISO will work with market participants to address two issues required for implementing insertion of generated bids for NRS-RA resources that fail to offer into the ISO markets. The first issue is the question of what bid price to insert for automatically generated bids, and the second is that of outage reporting for these resources.

2009 Rank: Not Ranked. This is new for 2010 Catalogue.

Status: The proposed modifications were approved in the July 2010 Board of Governors. Additional documentation is available at http://www.caiso.com/2488/2488b47711c30.html.

11.7.3 Rules and Procedures for Applying the Resource Adequacy Must Offer Obligation for a Subset of Hours (D)

Currently, resources that supply Resource Adequacy capacity and are subject to the RA Must Offer Obligation (RA-MOO) are subject to that obligation 24 hours per day, seven days per week (24x7). As a result, an RA resource must submit bids in ISO markets for the full amount of its RA capacity in all hours, except when it has submitted an outage notification to the ISO through the SLIC system. If the resource does not comply with this requirement, ISO market systems automatically inserts generated bids for the RA capacity that was not offered in a submitted bid. However, even currently, not all RA capacity is procured by LSEs on a 24x7 basis, some RA capacity is procured for a subset of hours, e.g., a 6x16 contract.

In contrast, the new design recognizes the contractual arrangements of these RA resources. Now, the ISO will insert bids (if the scheduling coordinator for the resource adequacy resource fails to do so) only for the hours specified in the RA contract. Under this proposal, RA resources will be required to provide information to the ISO about their subset-of-hours arrangements in a statement under oath. Thus, RA resources will be required to bid only in those hours and the ISO systems would insert generated bids, if necessary, only in those hours. This design will yield a more detailed and accurate representation of all RA contracts and resources in the ISO market systems which will result in a more accurate generated bids process. Because this change could potentially result in significant changes in LSE supply plan portfolio content, the ISO will work closely with the CPUC and other local reliability authorities to ensure that load serving entity RA requirements continue to meet the ISO's reliability needs.

2009 Rank: High

Status: This initiative was combined with Generating Bids and Outage Reporting for NRS-RA Resources (Section 11.7.2). The proposed modifications were approved in the July 2010 Board of Governors. Additional documentation is available at http://www.caiso.com/2488/2488b47711c30.html.

11.8 Seams and Regional Issues

No 2009 Catalogue initiatives were completed within the Seams and Regional Issues category.

11.9 Other

11.9.1 Pool of Resources in the Integrated Forward Market (D)

The ISO is considered modifying a current market rule which limits the pool of bids considered in the Integrated Forward Market (IFM) to resources that are dispatched in the Local Market Power Mitigation procedures run prior to the IFM (ISO Tariff Section 31.2). The ISO is considering three options on this market rule: 1) maintain the rule but continue to monitor market impacts under different market conditions; 2) modify tariff/BPM to give ISO operators the option of relaxing the rule if it is significantly impacting IFM results; or 3) modify tariff to require consideration of all bids in IFM.

2009 Rank: Not Ranked

Status: The modifications were approved by the Board of Governors in September 2009. Tariff language was approved by FERC in December 2009. Implementation is pending. Additional documentation is available at http://www.caiso.com/23d8/23d8bb9a6ee20.html.

11.9.2 Post Five-Day Process Price Corrections

Since the start of the new ISO market design on April 1, 2009, there have been isolated instances in which market prices were corrected outside of the five-day Price Correction Time Horizon. The ISO has not previously published the criteria used to evaluate whether a price correction is warranted after the expiration of the Price Correction Time Horizon. Through this initiative, the ISO will work with stakeholders to determine the circumstances under which post five-day price corrections may be made.

2009 Rank: Not Ranked

Status: The criteria were approved by the Board of Governors in May 2010. Tariff language was filed with FERC in June 2010. FERC approval is pending. Additional documentation is available at http://www.caiso.com/2733/2733dab218d20.html.

11.9.3 Data Release and Accessibility – Phase 1 and 2 (F, N)

The initiative will explore whether the ISO should adjust the type and/or amount of information provided to market participants, including information on constraints, contingencies, prices, market inputs and results. Phase 1 addressed the release of transmission constraints. Phase 2 addressed the release of Convergence Bidding information.

11.9.3.1 *Phase 1 – Transmission Contraints*

In November 2009, the ISO launched the Data Release and Accessibility Phase 1 - Transmission Constraints stakeholder process to evaluate information release policies that best support effective and efficient market participation. Stakeholders had expressed a need for information regarding ISO's management of transmission constraints in market operations. Stakeholders stated that increased transparency into the management of constraints would enable them to better understand ISO market results which would facilitate more effective participation in ISO markets.

Three new data release elements were approved by the Board and implemented in January and July 2010 as described here.[12]

1. ***Transmission Constraint and Contingency Lists in the Day-Ahead Market****.* The following datasets were implemented on July 13, 2010: (1) a post-day-ahead market constraints list published daily after the results of the day-ahead market are posted, and, (2) a pre-day-ahead market constraints list published daily after a preliminary market run that the ISO performs to review issues in preparing for the next day's day-ahead market. This information is only available to market participants via non-disclosure agreement (NDA). At this time, this information is provided for the day-ahead market due to the voluminous amount of information associated with the real-time market, which is run more frequently than the day-ahead market. See the Draft Final Proposal, Appendix A for Sample Tables, http://www.caiso.com/2716/2716f7aa4c070.pdf

2. ***Cause of Binding Constraint***. In addition to the current publication of the shadow price for each binding constraint on OASIS, the ISO now posts the cause behind the binding constraint at the same location. The new data show whether the constraint was binding under the base case (base operating conditions relevant to the different markets) or due to contingency conditions, in which case the ISO would identify the actual name of the contingency, similar to that in other ISOs. This provides market participants with additional insights into some of the driving forces behind observed congestion. For the list of affected OASIS reports, see the 1/13/2010 presentation to stakeholders, Slide 31, http://www.caiso.com/271b/271bf2e05b80.pdf.

3. ***Conforming Constraint Report for the Day-Ahead and Real-Time Markets***. The ISO now provides the public with a new monthly constraint report that includes the number and degree of manual adjustments to transmission constraints within the transmission grid controlled by the ISO for the day-ahead and real-time markets. These manual adjustments are made by market operators to conform and adjust transmission constraints and limits to ensure the market optimization has a realistic representation of the actual grid conditions or to allow the market optimization software achieve a more reliable solution based on operator observations of real-time conditions not captured by other market optimization inputs.

11.9.3.2 *Phase 2 – Convergence Bidding Information Release Contraints*

In December 2009, the ISO initiated a separate stakeholder process on Convergence Bidding Information Release[13] (Phase 2 of Data Release and Accessibility) to consider the release of additional information that would allow stakeholders to more effectively participate in ISO markets as convergence bidders. As a result of the stakeholder process, the ISO will release a daily market summary report and the hourly net cleared quantities of virtual bids by node at the close of the real-time market. Because the nodal information will be sufficiently aggregated, publishing the net cleared quantities by node is permissible under the ISO tariff. Therefore, this data release approach will not require a FERC filing. This information will be provided to the market in addition to the 90-day release of masked virtual bid data which the ISO committed to provide to as part of the convergence bidding design.

2009 Rank: Not Ranked

Status: Phase 1 and Phase 2 proposals were approved by the Board of Governors in February 2010. Tariff language for Phase 1 was filed on May 2010. Phase 2 did not require tariff modifications. FERC approval of Phase 1 occurred in July 2010. Phase 1 was implemented in July 2010. Phase 2 will be implemented with Convergence Bidding in February 2011. Additional documentation for Phase 1 is available at http://www.caiso.com/244c/244cae3b46bb0.html. Additional documentation for Phase 2 is available at http://www.caiso.com/2479/2479df7147660.html.

12. Deleted Initiatives from 2009 Catalogue

No items have been deleted from the 2009 Catalogue at this time.