Catalog of Market Design Initiatives

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Market and Infrastructure Development

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Catalog of Market Initiatives
July 2011

1. Introduction

The term *market design* is used at the California ISO (ISO) to describe policy changes and enhancements to the market rather than process improvements or administrative changes. This 2011 Catalog of Market Design Initiatives is a directory of market design initiatives that are:

- Potential enhancements for consideration – these proposals come from internal ISO staff and stakeholder suggestions.
- Currently in progress – Market design initiatives that are currently under way.
- Completed - These design efforts were completed since the last edition of the catalog
- Considered for deletion from the catalog – Based on their current status the ISO plans to delete these from the catalog. We are looking for stakeholder comments regarding the appropriateness of these decisions.

The catalog is designed to enable readers to easily locate initiatives of interest. The first 3 sections after this introduction (sections 2 through 4) describe initiatives related to the various ISO markets (day ahead, real time and residual unit commitment). This is followed by sections 5, 6, and 7 related to certain categories of products (ancillary services congestion revenue rights and convergence bidding). 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 catalog concludes with a Section 11 which holds the market design initiatives that have been completed and Section 12 lists initiatives that are being considered for deletion.

Consistent with previous versions of the catalog, 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

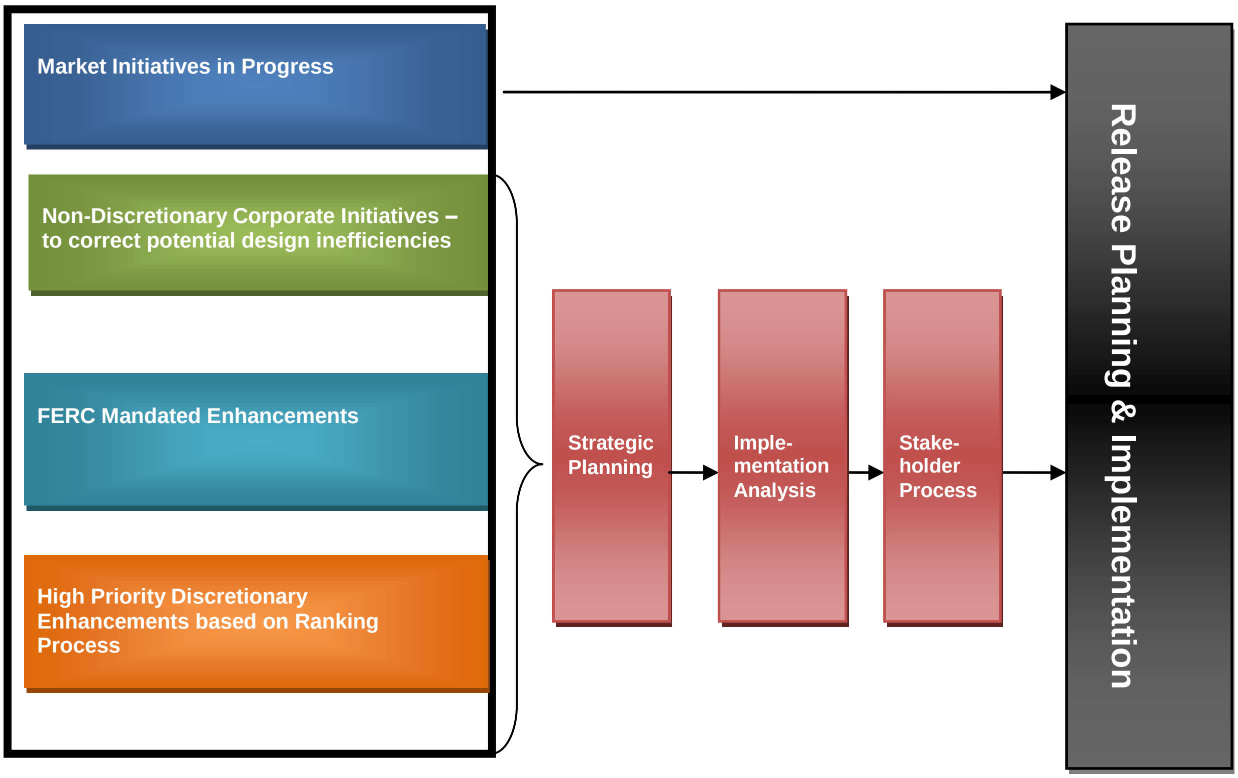
The design initiatives that are deemed *discretionary* are put through a ranking process to determine their priority based on their benefit to the market and their feasibility. A more detailed description appears later in this introductory section.

The ISO and stakeholders are currently engaged in a major market design initiative, *Renewable Integration Market and Product Review Phase 2* (RI-MPR Phase 2) which addresses large scale changes to the ISO market structure to accommodate renewable integration. The ISO views the market design changes being contemplated in this initiative as *non-discretionary* initiatives that are required to maintain system reliability and market efficiency. These enhancements are necessary to successfully integrate the significant amount of variable energy resources that will be added to the system to meet the state's RPS goals. Therefore the design elements resulting from the RI-MPR Phase 2 initiative will be given priority over other non-discretionary initiatives.

1.1 The Market Design Initiative Ranking Process

New market design initiatives are separated into the four categories described above (discretionary, FERC mandated, in progress/planned and non-discretionary) and are evaluated by the ISO. The process flow is shown in the diagram below.

Figure A- Market Design Process Flow



Each year the ISO performs an assessment of all of these initiatives. Together with stakeholders, the current catalog is reviewed for completeness and accuracy. In most years, the ISO performs an analysis and ranks each discretionary initiative based on overall benefit and feasibility[1]. This ranking process is performed in two steps, the high level prioritization and the detailed ranking.

High Level Prioritization

The ISO first conducts a high level assessment of proposed market initiatives in 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 is graded either “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 B below. The

[1] In 2010 the catalog was updated, but due to the number of non-discretionary initiatives associated with the implementation of the new market in 2009, discretionary initiatives were not ranked.

high level feasibility criteria utilize two measures: “Market Participant Implementation Impact” and “ISO Implementation impact”.

Figure B - ISO HIGH LEVEL PRIORITIZATION CRITERIA

#		Criteria	HIGH 10	MEDIUM 7	LOW 3	NONE 0
1	Benefit	Grid Reliability	Significant Improvement	Moderate Improvement	Minimal Improvement	No Improvement
2	Benefit	Improving Overall Market Efficiency	Significant improvement	Moderate improvement	Minimal improvement	No impact
3	Benefit	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	Feasibility	ISO Implementation Impact ($ and resources)	No Impact	Minimal Impact	Moderate Impact	Significant impact

Detailed ranking process

After determining the results of the high level prioritization the selected initiatives are ranked again using more detailed criteria based on stakeholder input. Each of these criteria has a weight associated with it, based on its relative importance. The weighting is a scale from 1 to 10 with 10 being the highest weight. For example, “Grid Reliability” is assigned a weight of 10 because it is a core function of the CAISO while “Process Improvement”, an important but not critical criterion, is ranked substantially lower at 5. Those proposed market initiatives that are ranked highest may be considered for future market design updates.

2011 Ranking Process Considerations

In 2011, the ISO initiated the Renewable Integration Market and Product Review Phase 2 to determine the changes that must be made to the ISO market structure to accommodate renewable integration. By the end of 2011, the ISO plans to complete a roadmap designed to outline the market changes which will be designed in 2012.
At this point it is unclear the extent of resources and time that will be devoted to the RI-MPR Phase 2 effort and it may be difficult to evaluate the feasibility of implementing market changes based on highly ranked discretionary market design proposals from this catalog.

The ISO is considering two options for the ranking process in 2011.

- Perform the high level ranking after evaluating stakeholder comments on the catalog. Capture the rankings for each initiative and perform the detailed ranking on the highly ranked initiatives after the RI-MPR Phase 2 roadmap has been established.

- Wait until the RI-MPR Phase 2 roadmap has been established to perform both steps in the ranking process. The ISO will have better information with regard to the magnitude of the Phase 2 changes when assessing discretionary market design recommendations.

We are looking for stakeholders' comments regarding their preference between these two options.

1.2 Next Steps

On July 15 the ISO will hold a conference call to discuss the catalog, the ranking process and coordination with the RI-MPR Phase 2 process. Stakeholder comments will due to the by August 1st. We are providing additional time for these comments due to the numerous market design efforts that are requesting stakeholder input during that time period.

We are looking for stakeholder input in the following areas:

- Suggested additions to the catalog
- Agreement/disagreement with proposed deletions from the catalog
- Preference regarding the timing of the ranking process.

2. Day Ahead Market Design

Since the start of the redesigned ISO 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.[2]

2.1 Marginal Loss Surplus Allocation (D)

Since the start of the new ISO market design, allocation of marginal loss surplus has been based on measured demand. Alternate approaches such as regional and regional adjusted for Path 26 flow have been proposed and studied. The ISO performed analyses for the alternate approaches in late 2010 and published an interim report on the results.

Status: The ISO intends to begin a stakeholder process in the latter half of 2011 to examine these and other proposals.

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.

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 catalog. The ISO believes that the Multi-Day Unit Commitment initiative can be expanded to address these concerns.

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

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 November.

2.3 Dynamic Pivotal Supplier Test for Market Power Mitigation (I)

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.

Status: This initiative is on the agenda for the July, 2011 Board of Governors meeting for approval.

2.4 Enhancements to Local Market Power Mitigation (F, I)

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.

Status: This initiative is on the agenda for the July, 2011 Board of Governors meeting for approval.

2.5 Load Aggregation Point (LAP) Granularity (F, I)

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[3] published on May 1, 2009 and "Comments on Barriers to Demand Response and the Symmetric Treatment of Supply and Demand Resources"[4] published on June 30, 2009.

Status: In February, 2011 the ISO filed a motion for an extension of time to implement this feature.

2.6 Startup and Minimum Load Cost Enhancements. (D)

SCE recommends the ISO implement a two-part start-up cost bid which would allow an SC to eliminate its exposure to fuel price volatility. The two-part start-up bid would contain a proxy value, to remove fuel price risk, and a fixed component to recover any per start fixed costs.

SDG&E highlights additional enhancements to more accurately represent dispatch costs. The ISO limits market participants to defining unit startup and minimum load costs as either purely fixed (Registered Costs - fixed dollars per startup and hourly minimum load costs) or purely variable (Proxy Costs - imputed fuel and aux power cost). However, a significant segment of supply resources have both fixed and variable startup components, for example due to provisions in power plant service agreements. These costs are documented and verifiable by the ISO. SDG&E proposes that the ISO enable market participants to define both fixed and variable cost components simultaneously in a unit's master file. More accurate representation of dispatch costs would improve market efficiency by removing the need for market participants to modify bids to mitigate the risk of under-recovering BCR.

This enhancement was evaluated but was not included as part of the enhancements developed through the commitment cost initiative that concluded in June 2010. The ISO's position on this is described on page 7 of the *Draft Final Proposal for Changes to Bidding and Mitigation of Commitment Costs* which is located at the following link: http://www.caiso.com/27b6/27b6b9b046550.pdf.

Status: None

2.7 Unit Commitment and Price Formation Improvements (D)

According to the ISO tariff, the objective function of the optimization is to minimize total bid costs. Currently, however, the optimization minimizes cost based solely on point estimates of key input variables. For example, cost minimization is done on a point forecast of load in various regions, with point assumptions of generation availability and performance, point assumptions on loop flow, transmission availability and ratings. However, in reality, none of these values are known with certainty, rather the best that can be expected is an estimated distribution of possible outcomes, each with associated probabilities they will materialize.

For a given set of fixed inputs, the optimization might very well produce a cost-minimized result, but actual costs are within a distribution of potential outcomes other than those assumed in the point estimate. Therefore, without taking into consideration the distribution of outcomes the robustness of the solution selected by the optimization is an unknown. To address this level of uncertainty the ISO's should consider modifications to recognize uncertainty and minimize costs on an expected basis rather than a point forecast basis. This initiative was added based upon SCE comments to the draft catalog.

Status: None

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

2.8 Uplift Treatment to Accommodate GHG (D)

The ISO will need to re-evaluate the existing policies associated with the current market-wide uplift treatment of emissions related costs. Cost-based values such as Default Energy Bids, proxy Start-Up Costs and Minimum Load Costs will likely need to be augmented to account for the costs of Green House Gas (GHG) emissions permits borne by generators. This initiative was added based upon PG&E comments to the draft 2010 catalog.

Status: Stakeholder process is anticipated to start in 2012-Q1 in time to have necessary changes in place before the scheduled 1/1/2013 launch of CARB's GHG cap and trade program.

2.9 DLAP Level Proxy Demand Response (D)

Currently, there is no mechanism for a Default Load Aggregation Point (DLAP) level PDR to be explicitly incorporated into the ISO market. Adding the ability to create a PDR at the DLAP level would allow potential DLAP wide dynamic rate tariffs to be explicitly incorporated into the ISO markets. This initiative was added based upon PG&E comments to the draft 2010 catalog.

Status: None

2.10 Reliability Must-Run Pump Load

The ISO is revising its tariff on reliability must-run pump load. With this initiative, the ISO proposes to create a new scheduling priority class in the integrated forward market for pump loads with reliability must run requirements. The new priority class will protect schedule of critical pump facilities from being interrupted prematurely.

Status: The ISO has discussed its proposal with stakeholders in multi-round stakeholder conference calls. At the request of the market participants that the policy will directly apply to, the stakeholder process was suspended. The market participants need time to analyze the implications of the policy. The stakeholder process could be re-opened at the request of the market participants.

3. 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]

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.[6]

3.1 Real-Time Imbalance Energy Offset (I)

Given the recent spike in imbalance energy offset charges (June 2010) and DMM's continued recommendations for improvements in this area, SCE requested this issue be added to the catalog and eligible for ranking in 2011. The ISO has conducted analysis and concluded there are three key drivers that contribute to the "imbalance" in real-time: (1) HASP and RTM price divergence, (2) hourly averaging effect on charging load for deviations in real-time, and (3) load forecast differences between HASP and RDT. In addition to identifying the three primary causes, the ISO has also proposed a revised allocation methodology, which would allocate imbalance energy offset costs, to the extent possible, based on cost causation principles. (In 2010 catalog this was titled "Imbalance Energy Market Neutrality Allocation).

Status: With the implementation of convergence bidding, a bidding strategy can be employed that seeks to arbitrage the historical price difference between HASP and RTD, but does not result in price convergence. Through the real-time imbalance energy offset (RTIEO) stakeholder initiative in 2011 intermediate options have been reviewed, but the current thinking is that only through the redesign of the real-time market can the root causes of the RTIEO be addressed and potential changes in the allocation methodology be developed afterwards.

3.2 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.

Status: None

[5] The business practice manuals are located at http://www.caiso.com/235f/235f939f8dc0.html on the ISO website.

[6] Ibid.

3.3 Directional Bidding in Real Time Market (D)

NCPA requests ISO add a new initiative to the Market Design Initiative Catalog 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 ISO 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 ISO 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 ISO 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 ISO 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 ISO 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 ISO 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.

Status: None

3.4 Flexible Ramping Constraint (I)

The California ISO plans to implement a new flexible ramping constraint in the market optimizations, including the residual unit commitment, hour-ahead scheduling process, real-time unit commitment, and real time dispatch. The flexible ramping constraint will help ensure sufficient ramping capability is available to meet conditions in the five-minute market interval during which conditions may have changed from the assumptions made during the prior procurement procedures. Enforcement of the constraint can produce opportunity costs for resources that resolve the constraint.

Status: In progress

4. 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.[7]

4.1 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.

Status: None

4.2 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.

Status: None

4.3 72-Hour RUC (I)

As a first step toward multi-day unit commitment, the ISO intends to extend the Residual Unit Commitment (RUC) process to a 72-hour process rather than a 24-hour unit commitment process. Extending the RUC to a 72-hour period allows the optimization solution to evaluate if it is economic to keep a resource online during off-peak hours versus cycling the resource off, based on the next day's load forecast conditions. The commitment decisions beyond the first 24 hours will affect the next Integrated Forward Market run for evaluation by setting the initial conditions across midnight. This RUC extension does not change the day-ahead market external communication and relevant settlement rules.

Status: The development of this initiative is scheduled to begin in the 3rd or 4th quarter of 2011

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

5. 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.[8]

5.1 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.

Status: None

5.2 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 ISO may be accounting for operating reserve capacity that may not be deliverable.

Status: None

5.3 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.

Status: None

5.4 Black Start Procurement (D)

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

[8] 8 BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html

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.

Status: None

5.5 **Fractional MW Regulation Awards (D)**

SDG&E proposes that the ISO establish minimum thresholds for regulation awards. SDG&E has observed that certain of its AGC-capable units receive regulation awards of as little as 0.01 MW, which is not only infeasible but also removes otherwise available capacity above the regulation range from the market. An effective solution would be to enable market participants to specify a minimum regulation award quantity.

Status: None

6. 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.

6.1 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 catalog based on comments submitted by two market participant in April 11, 2008 comments.

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.

6.2 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.

Status: None

6.2.1 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.

Status: None

6.2.2 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.

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 catalog. They will be ranked as one item.

6.3 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.

Status: None

7. Convergence Bidding Enhancements

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. Virtual bids pressure Day Ahead and Real Time prices to move closer together, thus reducing the incentive for buyers and sellers to forgo bidding physical schedules in the Day Ahead market in expectation of better prices in the Real Time market. Convergence Bidding is scheduled was implemented in February 2011.

7.1 Allowing Convergence Bidding at CRR Sub-LAPs (D)

Currently convergence bidding does not allow virtual bids at CRR Sub-LAPs. The ISO should consider adding sub-LAPs to the available locations for convergence bidding. This initiative was added based upon comments to the draft catalog by WPTF.

Status: None

7.2 Additional Bid Cost Recovery for Convergence Bidding (D)

Currently convergence bidding only addresses bid cost recovery for price corrections. The ISO should consider other justification for bid cost recovery related to convergence bidding. This initiative was added based upon comments to the draft catalog by the Western Power Trading Forum (WPTF).

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.

8.1 **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.

Status: The IOUs submitted a filing at FERC to propose a waiver from forced outage reporting for grandfathered and CPUC extended QF contracts.

8.2 **Standard Capacity Product Planned Outage Availability Incentive Review (D)**

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..

Status: This initiative is currently on hold.

8.3 **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.

Status: None.

8.4 Seasonal Local RA Requirements (I)

The ISO should adopt seasonal (e.g. Summer, Winter, Shoulder) Local RA requirements because the single annual requirement used today is overly simplistic. The application of the 90/10 requirement over the entire year is nonsensical because the ISO is a summer-peaking system, as evidenced by decades of load data. SDG&E's understanding is the ISO prefers this convention because it provides a safety cushion against outages and other contingencies across the year, even if load during non-summer months is well below the 90/10 forecast. SDG&E counters that such an approach results in unnecessary cost to market participants. For example, SDG&E is prevented from offering surplus RA capacity to the market that it has already claimed to satisfy the Local RA requirement. Such restrictions limit market solutions to efficiently allocating capacity costs among market participants.

Status: Under Consideration. SDG&E raised this issue in Phase 2 of the CPUC RA proceeding for compliance year 2012 in R.09-10-032. The CPUC declined to adopt a seasonal LCR for 2012. In June 20, 2011 reply comments on the proposed decision, the ISO offered to include preparation of a seasonal LCR study as a topic for discussion at this year's stakeholder meeting on the ISO's 2013 local capacity technical study. Assuming that appropriate parameters can be formulated and agreed upon by stakeholders, the ISO may conduct a pilot study, in conjunction with the 2013 local capacity technical study, to analyze what the seasonal local RA requirement would be for SDG&E's service area for the non-summer months.

8.5 Replacement Requirement for Scheduled Generation Outages (D,I)

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 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.

Status: Suspended. The ISO began this initiative in August 2010. Given the wide variety of opinions received from stakeholders on how this issue should be addressed and resolved, and a lack of broad stakeholder support for any of the many options discussed and explored with stakeholders during the stakeholder process, this initiative was suspended it in September 2010 to further evaluate stakeholder comments received and options for moving forward, http://www.caiso.com/27f1/27f1da3b56ef0.html. The ISO is still considering the manner in which it will re-engage on this initiative. In RA decision D.11-06-022 in R.09-10-032, issued in June 2011, the CPUC has eliminated the replacement requirement starting with compliance year 2013.

The ISO plans to launch a new stakeholder initiative in Q3 2011 on Outage Coordination Enhancements to develop additional tariff authority and tools to allow the ISO to manage scheduled generation outages without the current replacement requirement rule. The latter is scheduled for elimination by the CPUC in 2013 and beyond per the June 2011 RA decision in R.09-10-032

8.6 Deliverability of Resource Adequacy Capacity on Interties (I)

The ISO methodology for determining the intertie capacity needed to accommodate resource adequacy supplies currently uses only historical data. This methodology ignores planned capacity upgrades, which can result in interties having a very low or zero capacity value. The ISO is initiating a stakeholder process to explore alternative methodologies for determining the resource adequacy intertie capacity and to consider ways of reducing import barriers for resources developing outside the California ISO.

Status: BPM changes scheduled for completion in August, 2011

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. In SCE's comments to the draft catalog, they requested that the ISO should also consider allowing a 30-minute scheduling of inter-tie transactions if aligned with other BAAs.

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, and sees its implementation of dynamic transfers (discussed in section 9.3) as supporting the needs of intra-hour scheduling. The ISO has initiated a pilot project with BPA to demonstrate the workability of intra-hour schedules that are processed in the ISO's market as dynamic schedules. The Joint Initiatives work on intra-hour scheduling has been recognized in FERC's notice of proposed rulemaking on integration of variable energy resources (docket RM10-11-000). The ISO filed comments on March 2, 2011, supporting FERC's efforts to remove barriers to the integration of variable energy resources in a manner that aids in the reliable operation of the interconnected grid and recognizes the presence of such resources varies throughout the various regions of the country. The ISO's comments described how the ISO expects the use of dynamic transfers to meet FERC's objectives for 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. The ISO supports further development of the Efficient Dispatch Toolkit, and has described a conceptual framework for market-to-market coordination with the Energy Imbalance Market.

9.2 **Allocation of Intertie Capacity (D)**

To address how intertie capacity gets allocated as well as potentially provide more flexibility to how intertie schedule 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.

Status: None

9.3 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 Catalog 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.

Status: None

10. Other

10.1 Rules to Encourage Dispatchability of Intermittent Resources (I)

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.

Status: This initiative is included in RI-MPR Phase 1

10.2 Generation Interconnection Procedures Phase II (I)

On December 16, 2010, the Federal Energy Regulatory Commission conditionally approved tariff provisions to the generator interconnection process known as Generator Interconnection Procedures. These new procedures combined the small and large interconnection process into a single cluster approach and streamlined the timelines under the study process. Phase II addresses carryover issues from Phase I as well as other issues raised by stakeholders and the ISO. Issues encompass generator technical specifications, information accessibility, non-conforming large generator interconnection agreement provisions, study assessment methodology and posting requirements. To the extent ISO Tariff changes are necessary to implement any future changes; the ISO anticipates seeking Board of Governors approval prior to submission to FERC.

Status: Work Group meetings have been convened to explore issues.

10.3 Storage Generation Plant Modeling (D)

In its comment PG&E suggested that the catalog 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. Based upon comment to the draft catalog, PG&E highlighted that this initiative should not be isolated to pumped hydro, but more generally to all storage resources.

Status: None

10.4 Aggregated Pumps and Pump Storage

The ISO has done a preliminary analysis of how the MSG modeling functionality might be adapted to accommodate the particular operating characteristics of aggregated pumps and pump storage facilities. The envisioned changes would enable MSG to optimize the dispatch of such resources over different generating configurations as well as load configurations. To date, interest in using this enhanced functionality has been very limited. Consequently, the ISO is not actively working on extending the MSG model for aggregated pumps or pump storage facilities.

Status: On Hold

10.5 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.

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

10.6 Multi-Stage Generator Enhancements (I)

In December 2010, the ISO implemented modeling functionality that optimizes the commitment and dispatch of generating units that, by their physical nature, have multiple operating configurations. The MSG functionality is designed to take advantage of the inherent flexibility of these resources while respecting their operating characteristics and the costs of their operation. Through experience gained with MSG over the past seven months, analysis of commitment, dispatch, and market outcomes for MSG resources, and with the help of stakeholder feedback, the ISO has identified potential refinements to the MSG functionality.

Starting with this issue paper, the ISO is initiating a stakeholder process to review the identified potential refinements to the modeling of multi-stage generation units, and to solicit feedback and suggestions from interested stakeholders. The outcome of this process should determine the key policy features for modeling and dispatching multi-stage generating unit models, as well as any implications or related concerns such as Bid Cost Recovery for embedded generating units.

Status: In progress

10.7 Demand Response Net Benefits Test (F, I)

This initiative covers the ISO's proposal to fulfill FERC order 745 regarding demand response compensation in the organized wholesale energy market. FERC order 745 requires that:

- Demand response (DR) resources will be compensated at full LMP if the LMP is above a threshold price as will be determined by the Net Benefits Test.
- The Net Benefits Test will be performed monthly (by the 15th day) to establish the static monthly threshold price to be used in the next trade month.
- The threshold price is determined by the point where the net benefits of dispatching DR exceeds the marginal cost of DR.
- The net benefit of dispatching DR is estimated based on a representative aggregated supply curve for the trade month.

Status: In progress

10.8 **Regulatory Must-Take Generation (D)**

This ISO is proposing modifications to its tariff definition of regulatory must-take generation which will apply more generally to facilities capable of producing electricity in conjunction with industrial processes and thermal energy.

Status: The ISO has discussed its proposal with stakeholders in multi-round stakeholder conference calls. At the request of the market participants that the policy will directly apply to, the stakeholder process was suspended. the market participants need time to analyze the implications of the policy. The stakeholder process could be re-opened at the request of the market participants.

11. Completed Initiatives from 2010 Catalog

This section provides a list of the 2010 initiatives that have been completed.

11.1 **Initial Conditions Management (I)**

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.

Status: This was implemented first quarter of 2011.

11.2 **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 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.

Status: The Board of Governors approved this initiative in November 2010. The ISO filed the tariff amendment in May, 2011 and is currently waiting for an Order. Implementation is scheduled for April, 2012. Additional documentation is available at http://www.caiso.com/27ab/27ab6e875c2e0.html.

11.3 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)

Status: This initiative was approved by the Board of Governors in February 2011. The ISO plans to file this tariff amendment with FERC in Q3, 2011

11.4 Resource Transitions (D)

The purpose of this initiative was to develop ISO Business Practice Manual (BPM) provisions for how the ISO will establish a resource's Resource Adequacy (RA) deliverability status when the resource transitions from outside to inside the ISO balancing authority due to a change to 1) the resource's interconnection point, or 2) the ISO balancing authority boundary. These provisions will apply to resources that have previously supplied imported power but plan to establish a direct connection to the ISO grid as an internal resource. The existing ISO tariff and BPMs describe how to establish internal resource RA deliverability and how to allocate intertie RA deliverability to load-serving entities

Status: Completed June 9, 2011

11.5 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 Catalog

Status: In June 2011, the ISO BOG approved including expected outages in determining the capacity to release in the annual allocation and auction.

11.6 Allocation of RA Import Capacity (D)

The allocation of RA Import Capacity among market participants is currently prioritized by the allocation made in the prior year. This approach, similar to CRR allocations, is illogical because it locks in such allocations based on past data without requiring ongoing support to demonstrate the going-forward merit of these allocations. Over time, this process disadvantages market participants who wish to acquire out-of-state resources that could otherwise lower the cost of energy supply into the ISO, since the RA capacity value may not be realized. SDG&E proposes that the ISO implement a process whereby RA Import Capacity is allocated among market participants based on demonstrable need or benefit to the overall market.

Status: Completed. In March 2011, the ISO opened the Deliverability of Resource Adequacy Capacity on Interties stakeholder initiative, http://www.caiso.com/2b42/2b42b9378530.html.

The ISO completed the stakeholder process in May 2011 with the posting of the Draft Final Proposal (DFP). On June 9, 2011 Proposed Revision Request ("PRR") 444 was submitted to the business practice manual (BP) change management process, https://bpm.caiso.com/bpm/prr/show/PRR000000000444. Final BPM language is expected in early August.

11.7 Resource Adequacy – Hourly Supply Plan (D)

The current requirements for RA Supply Plans and Resource Adequacy filings are marked by conflicts in RA capacity counting conventions between the ISO and CPUC, for example how to account for planned outages. Further, these conventions cause a gap between planning and real-time capacity data that dilutes the operational usefulness of the RA program. To resolve these weaknesses, SDG&E proposes that RA Supply Plans be submitted with hourly resolution of capacity data. Conventional tools (i.e. Excel) enable this level of detail without significant burden to market participants, regulators or the ISO, provided that upfront data standards are adopted and maintained. For example, hourly resolution could eliminate the CPUC's convention of discounting capacity for planned outages, since hourly availability data from SLIC could be used to provide a more accurate forecast of available NQC on an hourly basis. Hourly RA values would also allow for more accurate depiction of demand response capacity, use-limited resource capacity and time-varying capacity of intermittent resources. Also, cost causation for ISO-procured capacity would be precisely identified, thereby reducing the need for inequitable distribution of such costs onto market participants. SDG&E requests that the ISO investigate the benefits/costs of this methodology to replace the existing reporting requirements.

Status: Complete. This enhancement was captured within the non-resource specific/subset of hours initiative which was approved by the ISO Board in July 2010.

11.8 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.

Status: This final proposal for this initiative was posted in September 2010 and no changes to the current market design were required.

11.9 Non-Generic RA

The ISO 20% Renewable Portfolio Standard ("RPS") Study confirmed that the current generation fleet has sufficient overall operational flexibility to reliably integrate renewables at a 20% RPS level in over 99 percent of the hours studied. However, additional flexible capacity will be needed to support a 33% RPS. The market or may not procure the necessary amount of flexible capacity over the next decade for the ISO to efficiently and reliably operate the grid. The ISO has raised this issue in the CPUC Resource Adequacy proceeding for 2012. On November 30, 2010, the ISO filed a proposal with the CPUC to expand the capacity procured under the RA program to include non-generic capacity procurement ("NGCP") levels, where load serving entities ("LSEs") would be incented to procure capacity with specific operational characteristics in their month-ahead RA showings. Under the NGCP proposal, the ISO would provide annual May and December assessments regarding the type and quantity of flexible capacity in the existing resource fleet and the year-ahead RA fleet. The ISO's NGCP proposal was not considered in the June 2011 decision in the 2012 RA proceeding.

Status: Completed. The ISO has posted a *Supplement to August 2010 Report on the Integration of Renewable Resources Operational Requirements and Generation Fleet Capability at 20% RPS, http://www.caiso.com/2bb3/2bb3e45232930.pdf.* This supplement is part of the ISO's continuing assessment of fleet capability and renewable integration requirements. The ISO plans to issue an assessment in December 2011 or January 2012. The ISO also will be discussing this topic in RI-MPR Phase 2.

11.10 **Small and Large Generator Interconnection Procedures (D,I)**

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.

Status: The Board of Governors approved this phase of the initiative in December 2010. A new initiative "Generation Interconnection Procedures in currently in progress and reflected in this catalog in section 10.2.

11.11 **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.

Status: This initiative was approved by the ISO Board of Governors in May 2011. The tariff amendment for near-term functionality will be filed in July 2011 and the remaining functionality is scheduled to be implemented by spring, 2013.

11.12 **Updating ICPM, Exceptional Dispatch Pricing and Bid Mitigation (F,I)**

The California ISO conducted a stakeholder process to re-design the Interim Capacity Procurement Mechanism (CPM) and Exceptional Dispatch replacement tariffs before the current ones expired on March 31, 2011. The proposal included adding the CPM as a permanent feature of the tariff, retaining the going-forward compensation mechanism, retaining the exceptional dispatch and bid mitigation process, adding a new feature to select resources based on their operational attributes and adding a new feature to retain and compensate resources which are at risk of retirement and needed for reliability. The ISO presented the proposal to the November 2010 Board of Governors meeting and was conditionally accepted by FERC in March 2011. FERC made the CPM tariff effective April 1, 2011 and the ISO is working with parties to address the questions raised by FERC in its order conditionally approving the proposal regarding the CPM compensation mechanism and Exceptional Dispatch bid mitigation.

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

11.13 **Data Release and Accessibility Release - Phase 3 (D,I)**

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 12 of the Catalog for information on Phases 1 and 2 of this initiative. In comments to the draft catalog, SDG&E requested that STUC Price Publication to be addressed in this initiative.

Status: Completed. Board Approval received on May 18, 2011.

12. *2011 Catalog Proposed Deletions*

This section contains initiative that the ISO is considering for deletion from the Catalog. Stakeholder input is requested on these initiatives.

12.1 *Pricing of Minimum Online Constraints (D)*

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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.2 *Forward Energy Products (D)*

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

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.3 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.4 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.5 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.6 *Sub-Hourly Scheduling (D)*

The ISO currently requires that bids/schedules be submitted at an hourly granularity in the Real-Time Markets (RTM) but may benefit from relaxing this requirement. While the Real Time Dispatch (RTD) outputs prices every 5 minutes, the bids for all resources are required to be constant for the entire hour. This can be an unnecessarily restrictive for intermittent resources that have intra-hour generation forecasts but can only self-schedule a single value. The restriction exposes intermittent resources that are not enrolled in the Participating Intermittent Resources Program (PIRP) to imbalance charges, settled at the RTD price, that are a consequence of the market systems and not a result of poor forecasting or performance. A stakeholder process on this initiative should include discussion on the appropriate sub-hourly scheduling interval. This initiative was added based upon PG&E comments to the draft 2010 catalog.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.7 *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.*

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.8 *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. Based upon PG&E comments to the draft catalog, this initiative will also address the automatic conversion of non-contingent reserves to "contingency only" upon a resource receiving an incremental reserve award in real-time.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.9 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position..*

12.10 *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 catalog as "discretionary" type initiatives that will be ranked.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.11 *Intertia Procurement (D)*

The increase in renewable resources may result in operational concerns due to lower system inertia. In order to address this emerging operational need, the ISO should consider additional products or services necessary to maintain system inertia. This item was added to the catalog per WPTF's comments to the draft catalog.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.12 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.13 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.14 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.15 *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.

Status: *Because of the potential enhancements in the Renewable Integration Phase 2 initiative it may be worthwhile to delay this initiative until the Phase 2 Roadmap has been established. We are looking for stakeholder comment on this position.*

12.16 *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.

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.*

12.17 *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

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

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

12.18 *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.

Status: *The ISO with stakeholders determined that this is an implementation issue. The CRR team has commenced a working group to address CRR proliferation.*

12.19 *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.

Status: *In the 2011 CRR Enhancements the ISO reviewed the ARR approach and proposed changes to the CRR market design; however, stakeholders were not supportive of a large redesign of the CRR market and preferred making incremental changes of the existing allocation/auction process. The ISO also concluded that an ARR system similar to the implementation of PJM and MISO would not result in a materially beneficial change versus the ISO's current allocation approach.*

12.20 *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.

Status: *The stakeholder who initially requested this feature has withdrawn their request.*

12.21 *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 catalog based on comments submitted by a market participant in April 11, 2008 comments.

Status: *This issue has not been discussed since 2008 and is being considered from deletion from the catalog.*

12.22 *Analysis of Uplift Drivers (D)*

The ISO should explore the drivers behind uplifts and determine if products or services are needed which would avoid uplifts. This initiative was added based upon WPTF comments to the draft 2010 catalog.

Status: *Many current stakeholder initiatives are looking at uplifts in specific forums. Since this is a general request, we are considering deleting it from the catalog.*

12.23 *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.

Status: *This issue may be deleted from the catalog pending stakeholder input.*

12.24 *Enhanced Decremental Energy 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 decremental energy 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 decremental energy 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.

Status: *This issue may be deleted from the catalog pending stakeholder input.*

12.25 *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 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.

Status: *This issue has been covered by the subset of hours initiative.*

12.26 *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 inter-ties 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.

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 ISO; it is the ISO'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 ISO's involvement in this matter, the*

ISO confirms that self provision of Ancillary Services at the interties is possible under Existing Transmission contract rights or Transmission Ownership Rights."

12.27 *Modify Sanctions for Late FORs (D)*

Currently sanctions for late Forced Outage Reports is $500/day each day such reports are late. This sanction structure is arbitrary because it does not differentiate between the impacts of such violations on system reliability. A sanction for a late report on a 10 MW unit that returns to service in several hours is the same for a 1,000 MW generator that is forced out of service for months. SDG&E requests that the ISO develop a sanction structure that reflects significance of the outage.

Status: *None.*

12.28 *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 Catalog. 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.

Status: *None*

12.29 *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 Catalog 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.

Status: *Non-firm (i.e. interruptible) imports can only be scheduled in the day ahead market and cannot be incremented in HASP or the real-time market, pursuant to tariff section 30.5.2.4, Appendix A (and other tariff sections). In addition scheduling coordinators scheduling interruptible imports will be responsible for the cost of the required spinning and non-spinning reserve, pursuant to tariff sections 11.10.3.2, 11.10.4.2 and 34.16.2 and would be expected to include this cost in its energy bid price if it were able to submit an economic bid.*

12.30 *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.*

Status: *The current market application takes into account the number of start-ups allowed in a 24 hour period in both the day ahead market and the real time market. The day ahead market and real time market also have an energy limit constraint, where the scheduling coordinator enters, through their bid, the maximum or minimum number of hours they can be on line and the system will determine if it is optimal to commit these resource.*