DRAFT Stakeholder Initiatives Catalog

DRAFT as of September 19, 2012

Prepared by

Market and Infrastructure Development

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Stakeholder Initiatives Catalog

1 Introduction

The *Stakeholder Initiatives Catalog*[1] documents current and proposed policy changes and enhancements to the ISO market design and infrastructure planning processes. This includes the design of the markets the ISO operates, products and services provided, and the way in which transmission infrastructure is planned and generation is interconnected. It does not provide a listing of process improvements or administrative changes that do not require a stakeholder process. The 2012 edition marks the first time both market design and infrastructure and planning initiatives are listed together. This change creates a single, comprehensive directory of currently in progress and potential stakeholder initiatives compiled from internal ISO staff and stakeholder suggestions. The catalog is comprised of the following 13 sections.

Section 1: Introduction – Introduces the catalog, explains the stakeholder-approved ranking methodology, and provides a timeline and next steps.

Section 2: Day-Ahead Market – Lists initiatives that mostly affect the day-ahead market.

Section 3: Real-Time Market – Lists initiatives that mostly affect the real-time market.

Section 4: Residual Unit Commitment (RUC) – Lists initiatives that mostly affect RUC.

Section 5: Ancillary Services – Lists initiatives that add to or improve upon ancillary services offerings.

Section 6: Congestion Revenue Rights – Lists initiatives that mostly affect congestion revenue rights.

Section 7: Convergence Bidding – Lists initiatives that mostly affect convergence bidding not addressed via other initiatives.

Section 8: Resource/Supply Adequacy Initiatives – Lists initiatives that mostly affect resource adequacy.

Section 9: Seams and Regional Issues – Lists initiatives that mostly affect the seams and broader WECC region.

Section 10: Infrastructure and Planning – Lists initiatives that most affect infrastructure and planning including generation interconnection.

Section 11: Other – Lists initiatives that do not obviously fall under any of the sections above.

[1] Previously referred to as the *Market Design Initiatives Catalog* or as the “market initiatives roadmap.”

Section 12: Completed Initiatives – Lists initiatives completed thus far in calendar year 2012.

Section 13: Catalog Deletions – Lists initiatives which will be deleted from the next version of the catalog because they are being addressed elsewhere or do not have broad stakeholder support.

Each initiative categorized in sections 2 through 10 reflect the market or design feature that it *most* affects. It is likely that an initiative listed under one category, such as the day-ahead market, will affect other markets and products and vice versa.

Consistent with previous editions of the catalog, each section further notes whether an initiative is in progress and its priority. The highest priority is a FERC mandated initiative followed by a non-discretionary initiative necessary to address significant reliability or market efficiency issues. The final designation is a discretionary initiative, which may be prioritized or "ranked" by the ISO and stakeholders based on its ability to provide reliability or economic benefits as compared to its costs. Each initiative has been identified with a letter code found next to its title noting its status and priority. The codes are:

I – In progress initiatives

F – FERC-mandated initiatives

N – Non-discretionary initiatives

D – Discretionary or "rankable" initiatives

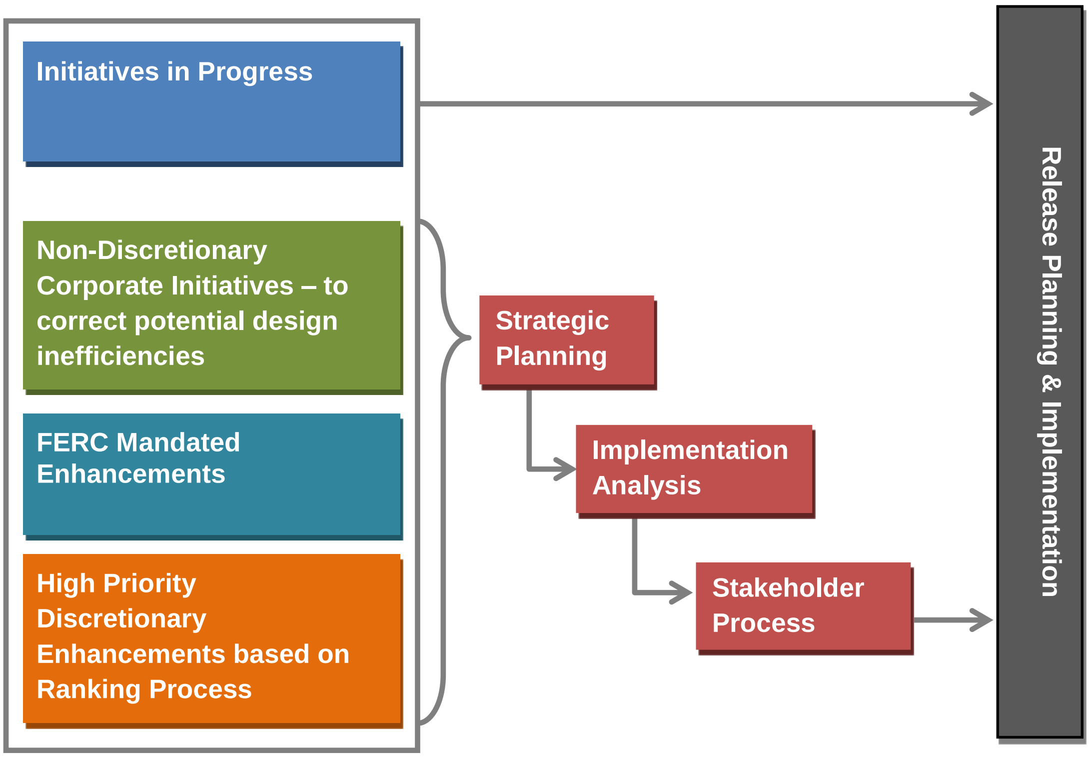
The *in progress* status code may be combined with any of the other three codes to show that a stakeholder process has begun and likely a webpage exists on the ISO stakeholder processes website.[2] For example, "I, F" indicates that a FERC-mandated initiative is currently going through a stakeholder process. An initiative deemed *discretionary* may be put through a ranking process to determine its priority based on its benefit to the market and feasibility. A more detailed description of this process is provided below.

1.1 Market Design Initiative Ranking Process

Initiatives are separated into the four categories described above (in progress, FERC mandated, non-discretionary, and discretionary) and are evaluated by the ISO. The process flow is shown in Figure A below.

[2] http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx

Figure A: 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[3]. 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 by applying a simplified ranking process of three benefit and two feasibility criteria based on stakeholder input and the ISO's assessment. 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 high level feasibility criteria utilize two measures: "Market Participant Implementation Impact" and "ISO Implementation impact". The total top score is 50.

[3] In 2011 the catalog was updated, but due to the number of non-discretionary initiatives, discretionary initiatives were not ranked.

Figure B: ISO High Level Prioritization Criteria

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

Detailed ranking process

If the high level rankings do not provide sufficient clarity on the priority of discretionary initiatives, top-ranking 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.

2012 Ranking Process Considerations

There are 13 initiatives currently in progress. Five of these are major FERC-mandated compliance issues and eight of these are non-discretionary items. There are eight additional FERC-mandated requirements and three non-discretionary initiatives yet to be addressed. This compares with 29 discretionary initiatives. From January through September 2012, the ISO has completed the policy stakeholder process for 23 initiatives and an additional 21 initiatives will be deleted from the next edition of the catalog as they are duplicative of other initiatives or no longer have broad stakeholder support.

Many of the in progress and FERC-mandated initiatives are closely related to the ISO's Renewable Integration Market and Product Review Phase 2 initiative started in 2011. Phase 2 initiatives span the short- and mid-term enhancements on the Renewable Integration and Market Design Vision and Roadmap presented to the ISO Board of Governors in 2011. These initiatives to integrate renewables are important because they address broad-reaching and fundamental changes to the ISO markets and planning functions to integrate significant levels of intermittent and distributed resources. They are aimed at aligning the market design with the characteristics of these intermittent and distributed resources to both accommodate these resources and to get the most out of the flexible resources that are needed to integrate these resources.

1.2 Proposed Timeline and Next Steps

Table A below has a proposed timeline, which includes the release of this draft catalog, a stakeholder conference call, and a two-week comment period. We aim to post the final draft to the ISO web site by mid-October.

Table 1: Proposed Timeline for the 2012 Stakeholder Initiative Catalog

Date	Event
September 19	Post draft 2012 Stakeholder Initiatives Catalog
September 26	Stakeholder conference call
October 10	Stakeholder comments due
October 17	Post final 2012 Stakeholder Initiatives Catalog

We ask stakeholders to use the comment period to provide three main pieces of feedback.

1. ***Review the discretionary initiatives for completeness***. In the first piece we ask that stakeholders provide in written comments any questions, clarifications, or preference to delete certain discretionary initiatives listed in this version of the catalog.

2. ***Add discretionary initiatives not listed in this version of the catalog.*** In the second piece we ask stakeholders to provide in written comments a detailed explanation of the new initiative, how it may affect market participants and/or the reliability or efficiency of the market, and when it needs to be addressed.

3. ***Rank discretionary initiatives.*** In the third piece we ask that stakeholders select five market design initiatives from the combination of those provided and any new initiatives and rank them according to the high level prioritization criteria shown in Figure B. For each initiative, we ask that stakeholders please provide a numerical score for all criteria except for "Desired by Stakeholders." Therefore, stakeholders should provide for each of the remaining four criteria a score of 0 to 10 for a maximum total of 40. After the ISO tallies the scoring, it may choose to provide a score for the "Desired by Stakeholders"

criterion. In addition to this scoring, each initiative should also have written comments providing a rationale for considering a particular initiative over others and discussing why a score was provided under each criterion. We also ask that the stakeholders focus on initiatives that would have broad market benefits. For example, a highly ranked initiative may affect many market participants or affect only a sub-set of market participants but have significant reliability or economic efficiency consequences.

Please consider the infrastructure and planning initiatives separately from the market design initiatives. Since there are only two discretionary initiatives for infrastructure and planning, a brief description of their importance or suggestions for new initiatives should suffice.

After the ISO receives this detailed feedback, we will provide the high level prioritizations in the next version of this catalog for stakeholder review.

2 Day-Ahead Market

Since the start of the redesigned ISO market, the day-ahead market has been operating well, laying the foundation for a series of planned and optional market enhancements that are expected to further improve the functioning of the day-ahead market. The structure and rules for the day-ahead market are presented in the business practice manuals for market operations and market instruments.[4]

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

The ISO currently settles load scheduled in the day-ahead market, as well as load settled in the real-time market, based on prices calculated for three load aggregation point (LAP) zones. These zones roughly correspond to the boundaries of the three investor-owned utility territories. 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 potentially inhibits the correct incentives due to the fact that these resources pay for underlying demand at the LAP price yet demand response is priced at a more granular level. 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[5] published on May 1, 2009 and "Comments on Barriers to Demand Response and the Symmetric Treatment of Supply and Demand Resources"[6] published on June 30, 2009.

Status: In February 2011 the ISO filed a motion for an extension of time and the FERC granted the extension to October 1, 2014.

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[4] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx
[5] http://www.caiso.com/241e/241eb5ba44d2.pdf
[6] http://www.caiso.com/23de/23dea1db21b0.pdf

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

This initiative is one of six market design enhancements that the FERC in its 9/21/06 MRTU Order agreed to allow the ISO to implement within three years after the start of MRTU on April 1, 2009. 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: FERC has granted the ISO's extension of time to April 30, 2014.[7]

Cross-Reference: FERC granted ISO an extension of time for the following six market enhancements: (1) a two-tier rather than single tier real-time bid cost recovery allocation (Section 3.6); (2) bid cost recovery for units running over multiple operating days (Section 2.2); (3) multi-hour block constraints in the RUC process (Section 4.1); (4) ancillary services substitution (Section 5.2); (5) exports of ancillary services (Section 5.3); and (6) over-collection of transmission losses (Section 2.3).

2.3 Marginal Loss Surplus Allocation (F)

This initiative (also referred to as over-collection of transmission losses) is one of six market design enhancements that the FERC in its 9/21/06 MRTU Order agreed to allow the ISO to implement within three years after the start of MRTU on April 1, 2009. 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: FERC has granted the ISO's extension of time to April 30, 2014.[8]

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[7] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

[8] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

Cross-Reference: FERC granted ISO an extension of time for the following six market enhancements: (1) a two-tier rather than single tier real-time bid cost recovery allocation (Section 3.6); (2) bid cost recovery for units running over multiple operating days (Section 2.2); (3) multi-hour block constraints in the RUC process (Section 4.1); (4) ancillary services substitution (Section 5.2); (5) exports of ancillary services (Section 5.3); and (6) over-collection of transmission losses (Section 2.3).

2.4 Multi-Stage Generator Bid Cost Recovery (BCR) (N)

The Bid Cost Recovery Mitigation Measures initiative (see Section 3.1) has developed a methodology to separately calculate BCR cost incurred in the day-ahead versus the real-time market. For non-multi-stage generators this is a straightforward calculation that clearly assigns costs to either market. However, multi-stage generators may be committed in different configurations between the day-ahead and real-time and under such conditions, the real-time cost as part of the overall cost of the two markets has not been systematically identified. Therefore, BCR cost of each of the two markets will require refinements when the separation of the netting of day-ahead and real-time markets is implemented. This initiative would seek to provide enhancements to the current process.

Cross-reference: This initiative would provide an enhancement to Bid Cost Recovery Mitigation Measures (see Section 3.1).

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

Currently, the forward looking time horizon in IFM is one day, which also takes 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 should 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 the 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 business practice manual for market operations.[9]

PG&E previously 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.

Status: The 72-Hour Residual Unit Commitment is an interim step that will provide some benefits until the full multi-day unit commitment solution can be implemented. The initiative was completed in 2011 and documentation can be found at http://www.caiso.com/27ae/27aebe3060d40.html.

2.6 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 (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.

Cross-reference: This initiative would address whether to pursue a method to price minimum load capacity/energy in the market. A potential long-term term approach may be extended LMP a.k.a. convex hull pricing (see Section 3.11) or day-ahead regional procurements of the flexi-ramp product (see Section 3.3).

2.7 Regulatory Must-Run Pump Load (D)

Previously referred to as “Reliability Must-Run Pump Load” in the 2011 Market Design Initiatives Catalog. The ISO is revising its tariff on regulatory 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 regulatory must run requirements. The new priority class will protect the 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,

[9] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

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

The real-time market consists of the real-time unit commitment (RTUC), short-term unit commitment (STUC), and the real-time dispatch (RTD). The hour-ahead scheduling process (HASP) is also part of the real-time market. It includes provisions to issue hourly pre-dispatch instructions to system resources that submit energy bids in the real-time market and to procure ancillary services from those resources. For more details regarding the real-time market refer to the business practice manuals for market operations and market instruments.[10]

3.1 Bid Cost Recovery Mitigation Measures (I, N)

Currently, the bid cost recovery calculation is performed over the entire trade day and netted across the day-ahead and real-time markets for that trade day. In this initiative, the ISO proposes to separate calculations for the day-ahead and real-time so that they are not netted together. This will provide increased incentives to provide economic bids in the real-time market. In addition, this initiative introduces performance measures to check for persistent uninstructed imbalances and ensure that dispatched energy receiving bid cost recovery is delivered. These measures aim to mitigate resource deviations that may inflate bid cost recovery payments.

Status: The ISO aims to present this initiative to the Board of Governors in November 2012 for approval.

Cross-reference: This initiative was originally introduced as part of the Renewables Integration Market and Product Review Phase 1. Day-ahead and real-time BCR for multi-stage generators will be addressed separately (see Section 2.4).

3.2 Exceptional Dispatch Mitigation in Real Time (I, N)

The current trigger for exceptional dispatch mitigation relies on the static quarterly assessment of path designations. With the Local Market Power Mitigation Phase 2 implementation, the static assessment will transition to a dynamic competitive path assessment, which flags paths as uncompetitive based on the presence of congestion. This feature will improve the accuracy of local market power mitigation within the market dispatch, but it introduces a gap in identifying and mitigating for exceptional dispatches that have local market power.

This initiative is addressing that gap through a separate set of path designations that are based on the dynamic designations and will be used in applying mitigation to exceptional dispatch. ISO also intends to provide a set of default path designations that will be used as a "back-up" in the event that the dynamic competitive path assessment within the market software fails to produce a valid set of path designations.

[10] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

Status: The ISO aims to present this initiative to the Board of Governors in November 2012 for approval.

Cross-reference: This initiative is part of Local Market Power Mitigation Phase 2.

3.3 Flexi-ramp Product (I, N)

The flexible ramping (flexi-ramp) product seeks to address the changes between the real-time pre-dispatch process and the five-minute real-time dispatch typically due to variability and uncertainties, especially from intermittent generation. Such flexible ramping capability is not covered by current ancillary services offerings in the CAISO market.

The ISO is proposing that the flexi-ramp product will be the amount of reserved ramping capacity procured in the day-ahead and real-time markets. Procurement will include both five-minute up and down quantities, procured as separate products and potentially with different procurement targets capacity bids and clearing prices in both day-ahead and during real-time pre-dispatch based on anticipated real-time pre-dispatch and real time dispatch deviations. The procurement is aligned with the real time dispatch market clearing interval so that the resource can be fully deployed in one real time dispatch interval if needed. The product will be co-optimized with energy and ancillary services and any portion of the capability deployed will be converted to energy schedules and receive real time dispatch energy payments.

In addition, generators in the Participating Intermittent Resources Program (PIRP) will be allowed to provide decremental bids in order to provide flexi-ramp down. This is related to and may fully address decremental bidding from PIRP resources (see Section 3.5). PIRP resources that wish to participate will provide its hourly PIRP schedule, a decremental bid price, maximum capacity (MW) to be curtailed from the PIRP schedule, a ramp rate, and flexible ramping down bid price.

Status: The ISO aims to present this initiative to the Board of Governors in November 2012 for approval.

Cross-reference: This initiative includes decremental bidding from PIRP resources (see Section 3.5). Both initiatives were originally introduced as part of the Renewables Integration Market and Product Review Phase 2. The flexi-ramp product is an improvement over the flexible ramping constraint interim compensation methodology introduced in 2011. The interim methodology only addressed upward ramping needs and was not based on economic bids. A cost allocation methodology has been proposed for this initiative (see Section 3.4). The flexi-ramp product may also consider day-ahead regional procurement which may address the pricing of minimum online constraints initiative (see Section 2.6). Furthermore, the ISO plans to address the Multi-hour Block Constraints in RUC initiative as part of flexi-ramp (see Section 4.1).

3.4 Flexi-ramp Product Cost Allocation Methodology (I, N)

The ISO proposes to allocate the costs for the flexi-ramp product (see Section 3.3) based upon "movement" every 10 minutes that requires changes in real-time dispatch of resources. For load, movement is the change in observed load while for generation it is the change in uninstructed imbalance energy outside a pre-defined threshold. For static intertie ramps and internal self-schedules, movement is calculated based upon the change in MWhs deemed delivered every 10 minutes. The ISO believes that movement is better aligned with the procurement decisions of the flexible ramping product because it represents the changes in real-time dispatch necessary to manage the system. The cost allocation methodology adheres to the ISO-developed cost allocation guiding principles (see Section 12.7).

Status: The ISO aims to present this initiative to the Board of Governors in November 2012 for approval.

Cross-reference: This initiative is an integral part of the flexi-ramp product initiative (see Section 3.3).

3.5 Decremental Bidding from PIRP Resources (I, N)

Some stakeholders have suggested adding the ability of PIRs to provide economic bids. While this option may increase the amount of decremental bids, it would be a significant undertaking from an implementation standpoint. The current system logic does not support self-schedules and bidding simultaneously. The current end-to-end process assumes that energy below a self-schedule is a penalty protected area which is not biddable and that this energy is a price taker which would not be included in bid cost recovery. The ISO's project office evaluated making a change to provide for economic bidding with PIRP self-scheduling and determined SIBR, RTM, MQS, SaMC and OASIS would be impacted. Given the implementation challenges, this initiative was placed as part of the RI-MPR 2 initiative.

Cross-Reference: This initiative will be addressed under the Flexi-ramp Product initiative (see Section 3.3).

3.6 Two-tier Rather Than Single Tier Real-Time Bid Cost Recovery (BCR) Allocation (F)

This initiative is one of six market design enhancements that the FERC in its 9/21/06 MRTU Order agreed to allow the ISO to implement within three years after the start of MRTU on April 1, 2009. The existing real time BCR cost allocation for the 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 BCR where the first tier would allocate costs based on cost causation principles.

In the FERC April 20 Order the ISO was directed to work with stakeholders to develop a proposal for two-tiered allocation of real-time BCR 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: FERC has granted the ISO's extension of time to April 30, 2014.[11]

Cross-Reference: FERC granted ISO an extension of time for the following six market enhancements: (1) a two-tier rather than single tier real-time bid cost recovery allocation (Section 3.6); (2) bid cost recovery for units running over multiple operating days (Section 2.2); (3) multi-hour block constraints in the RUC process (Section 4.1); (4) ancillary services substitution (Section 5.2); (5) exports of ancillary services (Section 5.3); and (6) over-collection of transmission losses (Section 2.3). This initiative will likely be discussed under the broader cost allocation overall market review (see Section 11.4).

3.7 Differentiated Curtailment Priorities for Overgeneration Events (D)

This initiative would explore whether differentiated curtailment rules are needed to alleviate overgeneration when market solutions (*i.e.,* available bids) have been exhausted. Currently, Section 7.8 of the ISO tariff allows the ISO to instruct scheduling coordinators to reduce either generation, imports, or both on a pro rata basis or for specific reductions. This assumes, for example, that self-scheduled resources are categorized into a single group and do not have different curtailment priorities. This initiative would explore whether curtailment priorities for self-schedules used by the market or for exceptional dispatch should be based on generation type (*i.e.*, flexible versus intermittent resources) or other attributes.

3.8 Directional Bidding in Real-Time Market (D)

NCPA requested the addition of this initiative to enhance and expand the structure of submitted bids within the real-time market to allow market participants to clearly communicate an offer to supply either incremental or decremental energy to the ISO. Under the current market design a

[11] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

market participant can submit an energy bid curve but this does not guarantee that the resulting award from the real-time market will be consistent with the direction the market participant desires (*i.e.,* either incremental or decremental only). NCPA contends this is particularly challenging for hydroelectric resources, which have specific operational constraints to manage storage requirements and may only be able to provide incremental or decremental energy. 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 or decremental energy through the use of a flag or other mechanism. NCPA contends this mechanism will improve grid reliability and market efficiency by allowing more capacity to actively participate in the real-time market.

3.9 DLAP Level Proxy Demand Response (D)

Stakeholder comment: PG&E comment on 2010 draft catalog - Currently, there is no mechanism for a default load aggregation point (DLAP) level proxy demand response (PDR) resource to be explicitly incorporated into the ISO market. Adding the ability to create a PDR resource at the DLAP level would allow potential utility DLAP wide dynamic rate tariffs to be explicitly incorporated into the ISO markets.

3.10 Extend Look Ahead for Real-Time Optimization (D)

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

3.11 Extended LMP, a.k.a. Convex Hull Pricing (D)

FERC has conditionally approved the use of extended LMP pricing for the Midwest ISO.[12] Extended LMP, or convex hull pricing, is a pricing methodology that incorporates the costs of resource commitment and dispatch in energy prices. LMPs only capture generator dispatch costs based on incremental production costs and do not account for unit start-up costs, minimum load costs, and minimum and maximum generation. These additional costs are typically incurred by fast start or fast response resources such as gas turbines and demand response. Extended LMPs aim to better reflect the full cost of satisfying demand. The Midwest ISO is subject to compliance filings with the FERC on the use of extended LMPs aiming towards full implementation in 2014. Adopting such a change would require additional changes to the ISO’s day-ahead market.

[12] Midwest Independent Transmission System Operator, Inc., *Order Conditionally Accepting Tariff Revisions*, Docket No. ER12-668-000, July 20, 2012.

3.12 Ramp Rate Enhancements (D)

Operational ramp rates are used for scheduling and dispatch in real time. In order to maintain performance of the market software within the required solution timing parameters, the number of operational ramp rate segments supported in the new market design is limited to four (versus 10 segments initially contemplated). Only 5 percent of the resources with operational ramp rates defined in the master file would have ramp rates with more than four segments defined. Some participants had concerns about the reduction in the number of ramp rate segments. Based on actual performance, the ISO could work with its software vendor to determine if additional operational ramp rate segments could 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 an ancillary service “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 ancillary services with energy dispatch from ancillary services capacity in real time.

4 Residual Unit Commitment (RUC)

The purpose of the RUC process is to assess any difference 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 business practice manual for market operations.[13]

4.1 Multi-Hour Block Constraints in RUC (F)

This initiative is one of six market design enhancements that the FERC in its 9/21/06 MRTU Order agreed to allow the ISO to implement within three years after the start of MRTU on April 1, 2009. 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: FERC has granted the ISO's extension of time to April 30, 2014.[14]

Cross-Reference: The ISO plans to address this issue under the Flexi-ramp Product initiative (see Section 3.3). FERC granted ISO an extension of time for the following six market enhancements: (1) a two-tier rather than single tier real-time bid cost recovery allocation (Section 3.6); (2) bid cost recovery for units running over multiple operating days (Section 2.2); (3) multi-hour block constraints in the RUC process (Section 4.1); (4) ancillary services substitution (Section 5.2); (5) exports of ancillary services (Section 5.3); and (6) over-collection of transmission losses (Section 2.3).

[13] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

[14] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

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

Early in the 2005 MRTU stakeholder process it was suggested that non-RA 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 non-RA internal generators that were not committed in the IFM. This initiative would consider whether 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.

5 Ancillary Services

The ISO procures four types of ancillary services products in the day-ahead and real-time markets: Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve. Section 4 of market operations business practice manual describes these ancillary services.[15]

5.1 Blackstart and System Restoration (I, F)

The ISO initiated this stakeholder process to address policy changes involving the administration of blackstart services consistent with NERC Reliability Standard EOP-005-2. The ISO separated this initiative into two phases based on stakeholder feedback. The first phase is addressed in the revised draft tariff language. This system restoration plan must be approved by the ISO Reliability Coordinator prior to July 1, 2013. The second phase will address how the ISO will procure blackstart capability, including how the ISO will compensate resources for this service and how the ISO will allocate costs to the market. This effort will require a more comprehensive amendment to the tariff, which will be addressed in 2013.

Status: The ISO is currently drafting tariff language as part of the first phase of this initiative.

5.2 Ancillary Services Substitution (F)

This initiative is one of six market design enhancements that the FERC in its 9/21/06 MRTU Order agreed to allow the ISO to implement within three years after the start of MRTU on April 1, 2009. 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, it 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: FERC has granted the ISO's extension of time to April 30, 2014.[16]

Cross-Reference: FERC granted ISO an extension of time for the following six market enhancements: (1) a two-tier rather than single tier real-time bid cost recovery allocation (Section 3.6); (2) bid cost recovery for units running over multiple operating days (Section 2.2); (3) multi-hour block constraints in the RUC process (Section 4.1); (4) ancillary services substitution (Section 5.2); (5) exports of ancillary services (Section 5.3); and (6) over-collection of transmission losses (Section 2.3).

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[15] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

[16] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

5.3 Exports of Ancillary Services (F)

This initiative is one of six market design enhancements that the FERC in its 9/21/06 MRTU Order agreed to allow the ISO to implement within three years after the start of MRTU on April 1, 2009. Under the new market design there is no formal mechanism or specific process for bidding for exports of ancillary services, or for scheduling on-demand export of ancillary services. 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 transmission capacity reservations 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: FERC has granted the ISO's extension of time to April 30, 2014.[17]

Cross-Reference: FERC granted ISO an extension of time for the following six market enhancements: (1) a two-tier rather than single tier real-time bid cost recovery allocation (Section 3.6); (2) bid cost recovery for units running over multiple operating days (Section 2.2); (3) multi-hour block constraints in the RUC process (Section 4.1); (4) ancillary services substitution (Section 5.2); (5) exports of ancillary services (Section 5.3); and (6) over-collection of transmission losses (Section 2.3).

5.4 Multi-Segment Ancillary Service Bidding (F)

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: The ISO filed a report with the FERC in March 2012.[18] The report concluded that since Scheduling Coordinators may submit multiple bid prices for ancillary services for a resource in the ISO's current markets, the market would not benefit from multi-segment ancillary service bidding at this time.

[17] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

[18] California Independent System Operator Corp., *Report of the California Independent System Operator Corporation on Potential Benefits of Multi-Segment Bidding for Ancillary Services,* Docket Nos. ER06-615-000, *et al.*, March 16, 2012.

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 may be to enable market participants to specify a minimum regulation award quantity.

5.6 Frequency/Inertia 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 potentially consider additional products or services necessary to maintain system inertia. This item was added to the catalog per WPTF's comments.

5.7 Voltage Support Procurement (D)

This issue involves the potentially developing a competitive procurement methodology for voltage support services. The ISO presented papers on both voltage support and black start during a stakeholder conference call on June 29, 2006. These papers concluded that there is a wide variety of procurement and cost allocation methods for these services and that further studies could consider a range of future options.

6 Congestion Revenue Rights

This section describes potential 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. Further details are available in the business practice manual for CRRs.[19]

6.1 Economic Methodology to Determine if a Transmission Outage Needs to be Scheduled 30 Days Prior to the Outage Month (D)

Currently the ISO's business practice manual for outage management 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, an interpretation of the tariff is that only outages that have a significant economic impact need to be scheduled 30 days prior to the month. The ISO would need to develop a process that performs an economic analysis to determine if a specific outage would have a significant economic impact. Such a process would 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 SCE and WPTF in April 11, 2008 comments.

Status: The operating transfer capability duration curve methodology which was approved by the Board of Governors in June 2011 may fully address the revenue inadequacy problem. The ISO will monitor this issue and determine if further steps are needed.

6.2 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.

[19] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

6.3 Long Term CRR Auction (D)

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 encouraged the ISO to initiate a stakeholder process and file tariff language to implement an auction for residual long term CRRs in a future release of the new market.

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 had been previously recognized by the ISO as an important potential CRR enhancement to enable a 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 existing transmission contracts and converted rights and previously-released long term CRRs). The multi-period optimization algorithm would 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 would 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 would likely be an essential component of a long term CRR auction.

With regard to flexible term lengths for long term CRRs (see Section 6.2), implementing a multi-period optimization algorithm would make it possible to market participants to choose additional terms beyond the current single 10-year term provided under the existing rules. The exact nature of the allowable choices would be decided as part of this potential stakeholder process.

6.4 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 second year CRR release process, but has deferred implementing this feature..

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.

6.5 Release of CRR Options (D)

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

6.6 Review the CRR Clawback Rule (D)

Stakeholder Comments: 10/31/11 Powerex comment - Powerex strongly recommends a new initiative to review the design and effectiveness of the CRR clawback rule. Powerex believes the ISO's unique CRR clawback rule is materially deficient in its design leading to: a) the ability of participants to submit small volumes of convergence bids, which inappropriately inflate the value of CRR holdings while crowding out physical supply and distorting efficient market outcomes; and b) undesirable discouragement of physical decremental bids in circumstances where no inappropriate CRR benefit could be gained. Powerex requests stakeholder discussions on this topic.

7 Convergence Bidding

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 was implemented in February 2011. Due to the high amounts of real-time imbalance energy offset and other related market inefficiencies, the FERC approved a temporary suspension of convergence bidding on the interties effective November 28, 2011. Given the impact of FERC Order 764, the ISO is working to reactivate convergence bidding at the interties in conjunction with redesigning how interties are dispatched and settled (see Section 9.1).

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

Currently convergence bidding does not allow virtual bids at CRR sub-LAPs. WPTF submitted comments suggesting that the ISO should consider adding sub-LAPs to the available locations for convergence bidding.

8 Resource/Supply Adequacy Initiatives

The ISO is an active participant in the broad area of supply adequacy, which is to a large extent the jurisdiction of state and local regulatory authorities. While we do not play a lead role, we do have very specific and essential responsibilities in almost all related activities.

To date the majority of procurement activities that will ultimately support long-term system security have been and are being conducted under the procedural umbrella of the CPUC's Long Term Procurement Plan (LTPP) Rulemaking. Related to this is the CPUC's resource adequacy (RA) proceeding as well as several more narrowly focused proceedings such as for demand response.

At the same time, the ISO has performed complementary activities including setting requirements for local capacity, backstop procurement to obtain additional capacity when the resources procured by the load-serving entities need to be supplemented, and implementing provisions in the ISO tariff that specify the ISO-market participation requirements or "must-offer obligations" applicable to resources that supply RA capacity. Now that the supply fleet is evolving to incorporate larger amounts of variable renewable resources such as wind and solar generators, the ISO's role in supply adequacy is evolving as well. In particular, given the ISO's responsibility for reliable operation of the transmission grid, the rapid increase in variable renewable resources requires the ISO to quantitatively assess future needs for flexible capacity and pursue initiatives to ensure that sufficient flexible capacity will be available when needed. Against this context, the initiatives described in this section address enhancements to the ISO activities in the area of supply adequacy.

8.1 Flexible RA Resource Capacity Performance and Must Offer Obligations (I, N)

The ISO is working with the CPUC and other local regulatory authorities (LRAs) to ensure there are adequate levels of flexible capacity resources to operate the grid reliably while fulfilling state environmental policy mandates. The ISO submitted to the CPUC a proposal for establishing an interim flexible capacity procurement requirement for the 2014 through 2016 RA compliance years. The CPUC and its stakeholders intend to enhance these interim requirements in the future with potentially a broader, more detailed requirement, potentially covering multiple years. The ISO's initiative will lead to tariff changes necessary to implement the proposed flexible capacity changes to the CPUC's and other LRAs RA programs. Specifically, the ISO will establish how the interim flexible capacity needs will be determined and allocated to local regulatory authorities for the interim period. The ISO will address availability and must offer requirements for different resources providing flexible RA capacity, including for use-limited hydro and thermal resources, as well as distributed generation. Similar considerations for non-dispatchable distributed energy resources and non-dispatchable use-limited resources will occur in a subsequent stakeholder process. Lastly the ISO will assess tariff changes needed to address default provisions for local regulatory authorities that fail to procure their allocated share of flexible capacity.

Cross-reference: This interim requirement would pave the way for a long-term solution, which could potentially include a Multi-year Forward Reliability Capacity Pricing Mechanism (see Section 8.3). The must offer obligations discussed under this initiative will be limited to those resources with a flexible designation. Must offer obligations for other resources will be considered under the Non-Flexible RA Resource Capacity Performance and Must Offer Obligations (see Section 8.4).

8.2 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 (referred to as SCP III) RA resources in the near future.

Cross-Reference: This initiative will be addressed under the Non-Flexible RA Resource Capacity Performance and Must Offer Obligations initiative (see Section 8.4).

8.3 Multi-year Forward Reliability Capacity Pricing Mechanism (D)

Previously referred to as the "Multi-year Forward CAISO New Generation Procurement Mechanism" in the 2011 Market Design Initiatives Catalog. This initiative would define tariff changes to address longer-term capacity procurement requirements with a horizon of up to five years into the future. This may include designing a multi-year forward reliability capacity pricing mechanism for transacting generic and flexible capacity. Questions that would be addressed in the initiative include, but are not limited to, determination of capacity needs, allocation of this need to local regulatory authorities, the actual pricing mechanism, self-provision of capacity, opportunities for new capacity builds (including distributed energy resources), price floor/ceiling, and performance obligations.

8.4 Non-Flexible RA Resource Capacity Performance and Must Offer Obligations (D)

This stakeholder process would evaluate the must offer obligations of RA resource types not addressed as part of the Flexible RA Resource Capacity Performance and Must Offer Obligations stakeholder initiative, completing a comprehensive review of all must offer obligations. First, based on the results of the Metering and Telemetry initiative, the ISO would assess potential changes to the definition of availability and must offer requirements in the ISO tariff for distributed energy resources and non-dispatchable use-limited resources that provide RA capacity. Second, the ISO will also undertake the Standard Capacity Product design for demand response resources (referred to as SCP III) as part of this stakeholder initiative. In its June 26, 2009 Order, FERC allowed the ISO to temporarily exempt demand response from the Standard Capacity Product availability payments and non-availability charges. FERC urged that this exemption end as soon as possible. The ISO will address this exemption as part of this initiative.

Cross-Reference: This initiative will be informed by the findings of the Metering and Telemetry initiative (see Section 11.5). This initiative will also address the Standard RA Capacity Product for Demand Response (SCP III) initiative (see Section 8.2). Must offer obligations for resources with flexible attributes are discussed under the Flexible RA Resource Capacity Performance and Must Offer Obligations initiative (see Section 8.1).

8.5 Seasonal Local RA Requirements (D)

Some stakeholders contend the ISO should adopt seasonal (*e.g.*, Summer, Winter, Shoulder) local RA requirements because the single annual requirement used today is overly simplistic. They contend the application of the 90/10 requirement over the entire year is not the right thing to do because the ISO is a summer-peaking system. SDG&E's states that they understand 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.

9 Seams and Regional Issues

This section 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.

9.1 FERC Order 764 Market Changes (I, F)

On June 22, 2012 the FERC issued a rulemaking on variable energy resources (Docket No. RM10-11-000; Order No. 764) and the ISO is launching a new stakeholder initiative to address compliance with the rulemaking. Order 764 requires the ISO to establish fifteen minute scheduling for intertie resources and likely allows for more comprehensive and effective real-time market changes to address issues related to the hour-ahead scheduling process.

Issues previously discussed in the Intertie Pricing and Settlement initiative (see Section 13.14) will be further addressed in the context of the rulemaking compliance. This will allow the ISO and stakeholders to develop real-time market enhancements that will likely provide a superior structural framework for re-introducing convergence bidding on the ties. This initiative will also serve as a more effective forum to address several other related issues such as real-time imbalance energy offset, price inconsistencies caused by intertie constraints, and the market structure for internal variable energy resources.

Cross-Reference: This is an umbrella initiative that will replace nine stand-alone initiatives, which are better addressed together and within the context of FERC Order 764. These separate initiatives will be deleted in future editions of this catalog. They are: (1) Additional Bid Cost Recovery for Convergence Bidding (see Section 13.2); (2) Allocation of Intertie Capacity (see Section 13.4); (3) Allow Virtual Bids on the Interties (see Section 13.5); (4) Creation of a Full Hour-Ahead Settlement Market (see Section 13.9); (5) Interchange Transactions after the Real Time Market (see Section 13.13); (6) Intertie Pricing and Settlement (see Section 13.14); (7) Real-Time Imbalance Energy Offset (see Section 13.17); (8) Sub-Hourly Scheduling (see Section 13.19); and (9) Transition out of the Participating Intermittent Resource Program (PIRP) (see Section 13.20).

9.2 Make Whole Process for Wheel-Through Transactions (D)

Under the current ISO market rules, wheel-through transactions can receive make-whole payments on the export side as a result of price corrections, but not on the import side. This can result in what could be considered either an under- payment or over-payment when the settlement of both sides if a wheel-through transaction is considered together. This initiative would develop new rules such that the make-whole calculations consider the settlement of both the import and export sides of wheel-through transactions affected by price corrections.

10 Infrastructure and Planning

This section includes policy initiatives related to infrastructure and planning. This broadly includes transmission planning and generator interconnection and deliverability for short- and long-term needs. This category encompasses both ISO-internal and inter-regional infrastructure and planning.

10.1 FERC Order 1000 Compliance (I, F)

This stakeholder process was launched in early 2012 to develop the necessary tariff revisions to comply with the Federal Energy Regulatory Commission's Order 1000 on transmission planning and cost allocation issued in July 2011. Order 1000 imposes requirements on the ISO in three primary areas: (1) regional (i.e., ISO system-wide) planning and cost allocation; (2) opportunities for non-incumbent transmission developers to build and own ratepayer-funded transmission; and, (3) interregional (i.e., western interconnection-wide) planning and cost allocation. The ISO is required to make two compliance filings – the ISO is required to file the necessary tariff amendments to comply with the first two areas by October 11, 2012; compliance with the third area must be filed by April 11, 2013. In June of 2010, the ISO filed significant tariff amendments with FERC substantially changing its transmission planning process and aligning the process with many of the considerations that were ultimately adopted in Order 1000. FERC approved those amendments on December 16, 2012 and the amendments went into effect on December 20, 2010 as part of the 2010-2011 planning cycle. As a result, the ISO's existing transmission planning tariff provisions largely comply with the requirements of the first two areas of Order 1000 noted above. In developing its compliance filing on the regional requirements of Order 1000 the ISO relied on its existing transmission planning process and tariff language to the greatest extent possible and proposed tariff amendments only where necessary to meet the specific requirements of the order with which the ISO's existing planning process does not already fully align. The proposed changes to comply with the regional requirements of Order 1000 were presented to the ISO Board of Governors in September 2012 for approval. Development of additional tariff revisions necessary to comply with the interregional requirements of Order 1000 are the subject of further efforts in this same stakeholder initiative and the resulting proposed changes will be presented to the ISO Board of Governors for approval in March 2013.

Status: The ISO Board of Governors approved the portions of this initiative related to meeting regional requirements in September 2012.

10.2 Generator Interconnection Procedures 3 ("GIP 3") (D)

The ISO is committed to working with stakeholders in an ongoing effort to improve our generator interconnection procedures to accommodate changes in the industry and the needs of our customers.

In this spirit, the ISO launched the GIP 3 stakeholder initiative in early 2012. In the GIP 3 initiative the ISO solicited stakeholder comments on the relative priority of approximately two dozen issues that should be considered. The ISO explained that a limited number of topics would be included in the initial stakeholder effort to ensure timely resolution and implementation. Stakeholders expressed broad support for only one topic – the extent to which an interconnection customer could downsize the MW capacity of its proposed generating facility. As a result of this stakeholder feedback, the ISO decided to defer work on the other topics of GIP 3 that did not receive such broad support and to focus the ISO's efforts on generator project downsizing through a separate stakeholder initiative. The GIP 3 initiative was deferred while the generator project downsizing initiative was pursued.

Status: As a point of clarification, stakeholders should be aware that on July 24, 2012 FERC approved the ISO's new Generator Interconnection and Deliverability Allocation Procedures ("GIDAP") (see Section 12.11). Although the ISO has retained the designation "GIP-3" to refer to the next round of enhancements to the interconnection procedures, the GIP-3 initiative may include enhancements that affect the existing GIP, which applies to interconnection requests in Cluster 4 and earlier, as well as ones that affect the GIDAP, which applies to Cluster 5 and beyond. In early 2013 the ISO intends to restart the GIP 3 initiative and revisit the relative priority of issues that should be considered. The remaining list of issues from the early 2012 GIP 3 effort will provide the starting point.

10.3 Transmission Interconnection Process (D)

During the FERC Order No. 1000 compliance initiative, some stakeholders suggested that a process is needed for participating transmission owners (PTOs) to provide reliability, operational and other technical feedback to non-incumbent transmission project sponsors seeking to interconnect to a PTO's existing transmission facilities. Some stakeholders also suggested that the ISO should take on a more active role in managing transmission interconnection applications.

Although currently the ISO's tariff governs generator interconnections, transmission and load interconnections are managed through applications to the PTOs under the terms of their transmission owner tariffs. Some stakeholders have expressed concern that having separate tariffs for transmission interconnections may result in interconnection studies not being properly sequenced between generator and transmission interconnections, and inconsistent tariffs and practices among PTOs may cause uncertainty and confusion. In addition, there may be cost allocation questions to be considered.

The number of transmission interconnection applications may grow in the future with the expanded opportunities for non-incumbent transmission owners to become project sponsors. The ISO acknowledges that suggestions for a single transmission interconnection process for the entire ISO footprint may have merit and the ISO should consider taking on a more active role in transmission interconnection applications.

Status: The ISO is considering starting a stakeholder process in Q2 of 2013 to explore possible options to address this topic.

11 Other

Market design initiatives in this section typically span more than one ISO market or product or involve special circumstance policy changes.

11.1 Administrative Pricing Rules (I, F)

This initiative is examining tariff provisions regarding market intervention in the event of significant system emergencies and the settlement implications of force majeure events. The ISO committed to this process in its FERC approved petition to waive tariff provisions for setting administrative prices and settling real-time market transactions related to the September 8, 2011 Pacific Southwest power outage.

11.2 Lossy vs Lossless Shift Factors (I, N)

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.”

11.3 Price Inconsistency Market Enhancements (I, N)

The ISO is seeking long-term solutions to address price inconsistencies occasionally produced in the ISO market when market solutions result in prices that do not cover the awarded bid prices. These inconsistencies can expose market participants to uneconomical awards and uncertain risks. This initiative is seeking to develop enhancements that would reduce or eliminate the root causes of price inconsistencies or implement settlement mechanisms to make resources whole to their bid prices. The proposal covers three sources of price inconsistency: (1) scheduling run versus pricing run; (2) point of delivery versus nodal constraint; and (3) APNode vs. Anode. For the scheduling run versus pricing run, the ISO proposes to use the MWs and prices from the pricing run. For point of delivery versus nodal constraint, the ISO has already implemented a software change that includes a physical location into the nodal constraints. For the last item, the ISO will use Anode prices for default load aggregation points and trading hubs across the market. Providing information about disconnected nodes was originally considered under this initiative as a potential enhancement but will not be pursued because further concerns needs to be addressed. The ISO will keep this item for future consideration.

Status: The ISO aims to present this initiative to the Board of Governors in November 2012 for approval.

11.4 Cost Allocation Overall Market Review (N)

This initiative will use the seven cost allocation guiding principles developed through a stakeholder process in 2012 (see Section 12.7) to review ISO's existing cost allocation methodologies. The review will check for consistency with the developed principles and suggest improvements where necessary. Several stand-alone cost allocation review initiatives have been subsumed under this umbrella initiative and most will be deleted in future editions of this catalog. These seven initiatives are: (1) Allocation of Dynamic Ancillary Service Costs (Section 13.3); (2) Consideration of Unaccounted for Energy (UFE) as Part of Metered Demand for Cost Allocation (Section 13.6); (3) Cost Allocation for Regulation (Section 13.7); (4) Cost Allocation for RUC (Section 13.8); (5) Marginal Loss Surplus Allocation (Section 2.3); (6) PIRP Cost Allocation (Section 13.16); and (7) Two-tier Rather Than Single Tier Real-Time Bid Cost Recovery (BCR) Allocation (Section 3.6). All of these initiatives will be deleted except for Marginal Loss Surplus Allocation and Two-tier Rather Than Single Tier Real-Time Bid Cost Recovery (BCR) Allocation. These two initiatives are FERC-mandated compliance items from the 9/21/06 MRTU Order and have been granted an extension of time to April 30, 2014.[20]

11.5 Metering and Telemetry Initiative (N)

Responding to market participant requests for additional options for metering and telemetry configurations, this initiative will investigate various options including data concentration and alternative security architectures to reduce barriers especially to support aggregated resource models. Pilots to verify options will be identified and executed as needed to adequately assure the alternative meets ISO requirements. ISO requirements will also be reviewed and modifications considered as needed to support new data concentration and aggregation models. The outcome will be updates to the business practice manual for telemetry and metering and potentially tariff changes.

Cross-Reference: The outcome of this initiative will inform the Non-Flexible RA Resource Capacity Performance and Must Offer Obligations initiative (see Section 8.4).

[20] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

11.6 Aggregated Pumps and Pump Storage (D)

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.

11.7 Rescheduled Outages (D)

Currently, Section 9.3.7 of the ISO tariff describes the process by which the ISO may cancel or change an Approved Maintenance Outage if it is “required to secure the efficient use and reliable operation of the CAISO Controlled Grid.” Section 9.3.7.3 describes what compensation will be paid to a Participating TO or Participating Generator as the result of the cancellation of an Approved Maintenance Outage. Stakeholders have indicated that they believe this may not adequately consider their situations and would like to re-examine these rules to ensure that they result in the most efficient operation of the grid and their resources, and that they ensure fair compensation.

11.8 Storage Generation Plant Modeling (D)

In its comment on the 2011 catalog, PG&E suggested that the catalog contain an initiative devoted to the proper modeling of pumped storage units. This would impact not only their Helms units, but other market participants who use, or are considering the use of, this type of generation. PG&E highlighted that this initiative should not be isolated to pumped hydro, but more generally to all storage resources.

12 Completed Initiatives

This section provides a list of initiatives completed in 2012 by September. For the purposes of this catalog, an initiative is considered completed if the policy development stakeholder process is finished. Therefore, initiatives may still be progressing through other processes such as tariff development or pending FERC approval. At times separate initiatives from previous catalogs have been simultaneously addressed through a single stakeholder process. To facilitate comparison with previous catalog editions, this section will count each original initiative as completed. In other words, if three closely related initiatives are simultaneously addressed under a single stakeholder process, this catalog will document three completed initiatives rather than a single initiative or four initiatives (if one counts those original initiatives plus the new combined initiative). The list is presented in alphabetical order with cross references, if any, to related initiatives. Initiatives presented here will be deleted from the next edition of this catalog.

12.1 Ancillary Services Forced Buy Back

The ancillary services forced buy back mechanism reduces ancillary service awards and self-provisions by the amount that is unavailable due to transmission constraints or plant limitations. Participants whose resources are subject to forced buy backs currently retain their capacity payments, which increases the cost of ancillary service procurements. This initiative aligned the settlement of ancillary services forced buy backs with existing rules of unavailable ancillary service capacity.

Cross-reference: The Multi-Settlement System for Ancillary Services initiative was addressed under the Ancillary Serviced Forced Buy Back stakeholder process and is considered completed (see Section 12.14).

12.2 Central Counterparty Issue – FERC Order 741

On May 25, 2012, the ISO filed with FERC to become a central counterparty to market transactions effective September 1, 2012, in compliance filing with FERC Order No. 741.

12.3 Circular scheduling

Circular scheduling occurs when the power scheduled for export from the source balancing authority returns back to the original scheduled import point and no power actually flows (source and sink are the same). A market participant can unduly profit from this practice while creating potential operational issues arising from a mismatch between scheduled versus actual flows. Following stakeholder discussion, the ISO r clarified existing market rules and created a settlement rule for circular schedules.

12.4 Commitment Costs Refinement

Since the implementation of the CAISO's LMP market design on April 1, 2009, the CAISO has made several market rule changes to increase the options and flexibility for market participants to specify start-up and minimum load costs. Commitment costs can either be calculated by the CAISO via a variable proxy cost, which is updated via the natural gas index and the heat rate of a unit, or via a registered cost submitted by the generator, which remains static for at least 30 days. In this initiative, the CAISO has refined its calculation of generator proxy start-up and maintenance costs by including: (1) costs associated with greenhouse gas emissions incurred under California's upcoming greenhouse gas (GHG) cap-and-trade program; (2) the cost of the CAISO's volumetric grid management charge; and (3) a fixed adder to cover major maintenance expenses. The registered cost cap has been revised down from 200% of the proxy cost to 150%. In addition, units required to respond to CAISO instruction causing them to deviate from delivered gas contracts and incur a penalty may be eligible for ex-post cost recovery.

Cross-reference: The following four initiatives were all addressed under the Commitment Cost Refinement stakeholder process and are considered completed: (1) Enhancements to Start-Up Bids to Recognize Fixed per Start Costs; (2) Re-evaluate Existing Policies Associated with Treatment of Certain GMC-related Costs; (3) Start-up, Minimum Load and Transition Cost Enhancements; and (4) Uplift Treatment to Accommodate GHG.

12.5 Congestion Revenue Rights Tariff Clarification 2012

The ISO proposed tariff clarifications for Congestion Revenue Rights (CRR) processes concerning the priority nomination process, seasonal eligibility quantity calculations, secondary registration, CRR PNode retirement, and credit requirements for load migration and merchant transmission. Some of these changes will impact the upcoming 2013 annual CRR process. This initiative sought to better align the tariff and business processes.

12.6 Contingency Dispatch Enhancements

The ISO will give dispatch priority during a disturbance control standard event to energy bids from resources providing operating reserves. Currently, the ISO dispatches energy in economic order and observes that resources providing operating reserves respond more accurately and quickly than energy-only resources. The change reduces the risk of not recovering from a disturbance event due to insufficient response.

12.7 Cost Allocation Guiding Principles

This effort was developed to establish guiding principles for cost allocation to be applied to the allocation of ISO market costs among market participants. The guiding principles will provide consistency and transparency for cost allocation in future ISO initiatives and further economic efficiency. The proposed cost allocation guiding principles have seven elements:

(1) Causation - costs will be charged to resources and/or market participants that benefit from and/or drive the costs;

(2) Comparable Treatment - similarly situated resources and/or market participants should receive similar allocation of costs and not be unduly discriminated against;

(3) Accurate Price Signals - the cost allocation design should support the economically efficient achievement of state and federal policy goals by providing accurate price signals from the CAISO market;

(4) Incentivize Behavior - provide appropriate incentives to market participants to ensure an economically efficient market;

(5) Manageable - the market design should seek to minimize variability and complexity of the allocation and maximize the transparency of cost drivers;

(6) Synchronized - cost drivers of the allocation should align as closely as possible to the selected billing determinant; and

(7) Rational - implementation costs/complexity should not exceed the benefits that are intended to be achieved by allocating costs.

These principles are initially applied to the flexi-ramp product as a "live test case" (see Section 3.4). Through a follow-up initiative, ISO will holistically review cost allocation methodologies developed through multiple stakeholder initiatives over the past 18 months to ensure consistency with these guiding principles (see Section 11.4).

12.8 Energy Self-Schedule Requirements for Self-Provision of Regulation

The ISO proposed tariff modifications to require that self-provided regulation submissions are accompanied with an energy self-schedule to support the self-provision. The need for this change was identified following an assessment that market performance efficiency was inhibited by customers submitting economic energy bids related to submissions to self-provide regulation.

12.9 Enhancements to Start-Up Bids to Recognize Fixed per Start Costs

This initiative was completed under the broader Commitment Costs Refinement initiative (see Section 12.4).

12.10 Flexible Capacity Procurement – Risk of Retirement

ISO's studies show that reliably operating the grid with multiple state energy policy mandates will require California to maintain an appropriate level of flexible and local capacity resources both now and into the future. Ensuring sufficient flexible and local capacity resources requires the ISO to expand its capacity procurement tariff authority. In this initiative, the ISO has pursued tariff changes that ensure the ISO has sufficient backstop procurement authority to address capacity at risk of retirement that the ISO identifies as needed up to five years in the future to maintain system flexibility or local reliability. The ISO Board of Governors approved this initiative in September 2012.

12.11 Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

The new generator interconnection and deliverability allocation procedures (GIDAP) will better align the transmission planning process (TPP) and generator interconnection procedures (GIP). CAISO has seen a significant increase in GIP requests, especially from renewable generation. However, the generator interest far outstrips the current renewable portfolio standard target and at least 75% of all requests may fail to reach commercialization. This complicates and delays the GIP process. On the other hand, CAISO's revised TPP already identifies high-voltage upgrades specifically to meet public policy goals. Therefore, under the GIDAP qualified generators will be accepted into the TPP up to a pre-specified MW volume of deliverable energy in specific study areas. The GIDAP will provide several important benefits, including: (1) incentivizing generation developers to interconnect with the grid where it is more efficiently planned thereby decreasing ratepayer costs; (2) increasing the probability that projects will achieve commercial operation; (3) providing greater certainty for generation developers in terms of siting and permitting; (4) providing greater transparency; and (5) encouraging non-incumbent transmission development. The GIDAP has received FERC approval (July 24, 2012) and pending clarifications will be applied prospectively beginning with queue cluster 5.

12.12 Generator Project Downsizing

This initiative was launched in early 2012. The state's renewable policy goals have resulted in significant development of new renewable solar and wind projects. The design of these projects is often scalable and, as a result, the developer may find it desirable or necessary to reduce the size of the project from what was originally proposed. In some cases, interconnection customers in the ISO queue desire to downsize previously submitted projects in response to changes in economic and financing conditions since the time they submitted their interconnection applications. In other cases, a customer may want to downsize because it does not expect to secure a power purchase agreement to cover the full output of its originally planned megawatt capacity. Through this stakeholder process the ISO developed a proposal in response to such generation developers for additional opportunities to downsize the megawatt capacity of their projects.

Status: The ISO Board of Governors approved this initiative in September 2012.

12.13 Inter-SC Trades Oversight Exemption

The ISO proposed to exempt inter-scheduling coordinator trades as part of the products and services that it believes should not fall within the oversight of the pending Commodity Futures Trading Commission (CFTC) market regulation. If these trades are not excluded, the ISO market would need to comply with the full range of requirements imposed by the Commodity Exchange Act - a significant burden for the ISO and its market participants.

12.14 Multi-Settlement System for Ancillary Services

This initiative was completed under the broader Ancillary Services Forced Buy Back initiative (see Section 12.1).

12.15 Outage Management Enhancements

This initiative was completed under the broader Replacement Requirement for Scheduled Generation Outages initiative (see Section 12.20).

12.16 Pay for Performance Regulation

FERC Order No. 755 requires that the ISO modify the compensation mechanism for regulation to include a performance payment with an accuracy adjustment in addition to the existing capacity payment. While CAISO already procured regulation (up and down as separate products) on an hourly basis, certain changes to the compensation method were made to comply with the FERC order. The FERC order required a two part payment for frequency regulation: (1) a payment for the regulation capacity offered and (2) a payment for the performance of the resource in response to the regulation signal as opposed to an administrative price. For capacity payments, CAISO revised its current practice to comply with the FERC order by creating a separate bid component for capacity and will allow scheduling coordinators to include inter-temporal opportunity costs in their regulation bids. For performance, CAISO revised its current practice to include “mileage” payments, or payments for the absolute change in Automatic Generation Control set points between four second intervals to which a regulation resource responds. The mileage payment will be based on actual mileage while the mileage award will be two constraints: (1) greater than or equal to the capacity award, (2) less than or equal to the capacity award multiplied by a resource mileage multiplier.

12.17 Post Emergency Bid Cost Recovery Filing Review

The ISO made two emergency filings with FERC in the first half of 2011 to mitigate observed adverse market behavior. Several strategies were being employed that aimed to expand uplift payments. The ISO committed to conducting a process for stakeholders to comment and raise any further changes or refinements to proposed tariff amendments. The ISO has opened this initiative as a forum for stakeholders to discuss market behavior that expands bid cost recovery uplift payments and develop rule changes if necessary needed to address such behavior.

12.18 Re-evaluate Existing Policies Associated with Treatment of Certain GMC-related Costs

This initiative sought to consider the new grid management charge (GMC) in minimum load costs. This initiative was completed under the broader Commitment Costs Refinement initiative (see Section 12.4).

12.19 Regulatory Must-Take Generation

The ISO revised its tariff definition of regulatory must-take generation related to combined heat and power resources to make it more applicable to facilities capable of producing electricity in conjunction with their industrial processes and thermal energy uses. The new definition will allow combined heat and power resources to establish a capacity level eligible for regulatory must-take generation scheduling priority even though the resource is no longer subject to a grandfathered power purchase agreement. The ISO also clarified that once grandfathered power purchase agreements have terminated resources will be required to comply with the ISO tariff. Current policy exempts facilities with grandfathered power purchase agreements from complying with the ISO tariff.

12.20 Replacement Requirement for Scheduled Generation Outages

The California Public Utilities Commission will eliminate its resource adequacy replacement rule starting in 2013. At the request of the commission, the ISO developed the market rule and tariff changes needed to ensure that load serving entities and suppliers replace their committed resource adequacy capacity that is unavailable because of a scheduled outage.

Furthermore, the April 30, 2010 FERC Order (Docket No. ER10-319-000) requires Eligible Intermittent Resources, such as wind and solar, that have a maximum output capability of 10 MW 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 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.

Cross-reference: The two initiatives listed below were addressed under the Replacement Requirement for Scheduled Generation Outages stakeholder process and are considered completed: (1) Outage Management Enhancements; and (2) Standard Capacity Product Planned Outage Availability Incentive Review.

12.21 Resource Adequacy Deliverability for Distributed Generation

This stakeholder initiative was launched in December 2011. Through this stakeholder initiative the ISO developed a proposed annual process for distributed generation resources to obtain resource adequacy deliverability status, so that load-serving entities can count these resources towards their annual resource adequacy requirements. The ISO developed this proposal to align ISO policy with the state's emphasis on distributed generation – relatively small-scale resources connected to utility distribution systems located close to load – as a key element of California's strategy for increasing the share of renewable resource production in annual electricity consumption. The proposal enables distributed generation resources to obtain deliverability status in about half the time it takes to go through the normal interconnection processes, and without requiring additional delivery upgrades to the ISO grid. The proposal was approved by the ISO Board of Governors in May 2012.

12.22 RUC Self-Provision

The FERC's 9/21/06 MRTU Order (Paragraph 172) directs the ISO to work with market participants on RUC self-provision. This would consist of a mechanism that enables internal ISO load to avoid RUC costs if it can be shown that sufficient resources are committed to meet the load. On March 28, 2012, the ISO submitted a report to the FERC (RUC Report) showing that RUC capacity and associated costs were very low and did not justify pursuit of self-provision enhancements under the current market design.[21]

On June 12, 2012 the FERC issued an order accepting the ISO's RUC Report and finding that the ISO has satisfied the requirements of the MRTU Order.[22]

12.23 Seven Day Advanced Outage Submittal

California ISO Tariff Section 9.3.3 gives the ISO the authority to reject outages submitted in less than 72 hours but does not address rejecting outages submitted less than seven days and greater than 72 hours. The ISO proposed tariff revisions that clarify when a transmission outage request must be submitted and provided criteria for accepting or rejecting outages that are submitted less than seven days in advance of the outage start date. Submitting outage requests in advance will allow the ISO to complete needed analysis and provide approvals in time to comply with Western Electricity Coordinating Council (WECC) reporting requirements.

[21] California Independent System Operator Corp., *Report and Motion of the California Independent System Operator Corporation on Residual Unit Commitment Self-Provision*, FERC Docket Nos. ER06-615-000, *et al.*, March 28, 2012.

[22] California Independent System Operator Corp., *Order Granting Motion for Extension of Time and Waiver Request*, FERC Docket Nos. ER06-615-000, *et al.*, June 12, 2012.

12.24 Standard Capacity Product Outage Reporting Requirement

This initiative was completed under the broader Replacement Requirement for Scheduled Generation Outages initiative (see Section 12.20).

12.25 Start-up, Minimum Load and Transition Cost Enhancements

This initiative was completed under the broader Commitment Costs Refinement initiative (see Section 12.4).

12.26 Uplift Treatment to Accommodate GHG

This initiative was completed under the broader Commitment Costs Refinement initiative (see Section 12.4).

13 Catalog Deletions

The following initiatives have been deleted and will not be carried forward to the next edition of the catalog. Most initiatives were deleted because they have been addressed or are subsumed under another initiative listed in the catalog. For these initiatives we provide the name of the ongoing initiative. For the remainder of the initiatives, the majority were deleted because they are no longer relevant or for lack of interest.

13.1 A/S Maximum Capability Operating Limits for Spin and Non Spin

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.

13.2 Additional Bid Cost Recovery for Convergence Bidding

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).

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.3 Allocation of Dynamic Ancillary Service Costs

SCE recommended that with the finalization and implementation of rules for dynamic transfers and pseudo-ties, the ISO must address how to allocate costs associated with these changes. SCE recommended that cost allocation be done based on cost causation principles. This structure creates correct price signals and aligns with the ISO's transparency principle, stipulated in RI-MPR Phase 2.

Cross-Reference: This initiative will be discussed in the cost allocation overall market review (see Section 11.4).

13.4 Allocation of Intertie Capacity

This initiative would consider alternatives means to allocate intertie (scheduling) capacity to provide more flexibility for market participants. One approach is to consider allocating capacity via an OASIS approach separate from the market. If a market participant is allocated capacity, it will then be allowed 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.

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.5 Allow Virtual Bids on the Interties

Stakeholder Comments: Numerous parties have expressed interest in re-instating virtual bidding on the interties. .

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.6 Consideration of Unaccounted for Energy (UFE) as Part of Metered Demand for Cost Allocation

The State Water Project (SWP) in its MRTU filing to FERC requested that UFE be allocated load based costs. In its filing SWP provided the 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.

Cross-Reference: This initiative will be discussed in the cost allocation overall market review (see Section 11.4).

13.7 Cost Allocation for Regulation

SCE has stated that the uncertainty and variability of VERS creates situations where Regulation is used to integrate these resources. Cost of regulation should thus flow to both load and to VERs in accordance with cost-causation principles. Alternative integrating products, such as the proposed Flexi-ramp Product, are not anticipated for implementation until 2013. Thus, current rules will unfairly charge load for intermittency associated with VERs for years. An initiative on this topic should be established and prioritized to avoid unjust and unreasonable cost-allocation.

Cross-Reference: This initiative will be discussed in the cost allocation overall market review (see Section 11.4).

13.8 Cost Allocation for RUC

Stakeholder Comments: SCE states the ISO plans to use RUC for renewable integration in the form of a more granular RUC that considers uncertain renewable output. SCE contends that in line with cost causation principles, costs for renewable integration should flow to the scheduling coordinators of VERs. Currently, load pays for RUC. This issue should be added to the calendar and addressed in coordination with the implementation of expanded duties for RUC.

Cross-Reference: This initiative will be discussed in the cost allocation overall market review (see Section 11.4).

13.9 Creation of a Full Hour-Ahead Settlement Market

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.

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.10 Enabling "Bilateral Energy Excluded from Settlements (BEEFS)

BEEFS would allow market participants the opportunity to settle energy transactions outside of CAISO settlements (*e.g.,* bilaterally). Draft tariff language has been proposed to address this concern for self-schedule generation from generation financed by municipal tax-free bonds. Therefore, this initiative will be deleted from the catalog.

13.11 Forward Energy Products

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.

13.12 Import or Export Bid Submissions from Multiple Scheduling Points

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.

13.13 Interchange Transactions after the Real Time Market

This item would 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 balancing authority areas (BAA).

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.

Stakeholder Comments: SCE recommends that this initiative be included in RI-MPR2.

10/31/11 Powerex comment – Supportive of the ISO aligning its scheduling practices with adjacent markets. However, Powerex believes this initiative should be a mid-term initiative given the slow progress in the remainder of WECC. Moreover, Powerex believes the ISO needs to address unit commitment and balancing reserve issues ahead of rushing forward with intra-hour scheduling of interties.

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.14 Intertie Pricing and Settlement

This initiative had been started by the ISO to seek long-term solutions to address the real time imbalance energy offset and pricing inefficiencies between the hour-ahead schedule process and real-time market. These issues were identified during the Real-Time Imbalance Energy Offset initiative and Price Inconsistency Caused by Intertie Constraints initiative. The primary focus of this stakeholder process is to find solutions to intertie pricing and settlement that reduce the real-time imbalance energy offset. The secondary objective of this initiative is to potentially provide a mechanism that allows convergence bidding at the interties.

The ISO will no longer pursue near term options for implementing convergence bidding on the interties. Fundamentally, after over a year of careful consideration, none of the options that have been proposed for reintroducing convergence bidding at the interties appear to improve overall market efficiency. At the same time many of the options considered create additional complexities for the market and operations and introduce new market and operational risks. Instead, the topics under this initiative are more effectively addressed within the real-time market changes required under FERC Order 764.

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.15 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.

This initiative has been deleted for lack of interest.

13.16 PIRP Cost Allocation

PIRP will be retained for existing PIRP resources and available to new participation. Uplift costs from PIRP will be allocated to load serving entities that have contracted with PIRP resources. For a new wind or solar resource to participate in PIRP they and their contracting load serving entity will need to provide a letter to the ISO confirming their desire to place the resource in PIRP. Once in PIRP, the uplift costs for that particular resource would then be allocated to the contracting load serving entity. Resources currently participating in PIRP will also need to provide the ISO information on their contracting LSE to enable the change in cost allocation discussed above.

Cross-Reference: This initiative will be discussed in the cost allocation overall market review (see Section 11.4).

13.17 Real-Time Imbalance Energy Offset

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.

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.18 Simultaneous Residual Unit Commitment (RUC) and IFM

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

13.19 Sub-Hourly Scheduling

PG&E noted in comments on the 2010 draft catalog that 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.

Stakeholder Comments: SCE recommends that this initiative be included in RI-MPR2.

10/31/11 NRG comment – While greater granularity of scheduling and settlement may be an intriguing idea to explore, NRG is suspicious of design initiatives that would confer benefits only on a certain technology of resources.

10/31/11 Powerex comment – Supports sub-hourly scheduling but believes this should be discussed as part of "Intertie Pricing" initiative.

10/31/11 – SCE comment – The catalog should reference that this initiative overlaps with "Intertie Pricing".

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.20 Transition out of the Participating Intermittent Resource Program (PIRP)

Stakeholder Comments: 10/31/11 SCE comment – PIRP is known to create operational challenges and to subsidize output from VERs by shielding these resources from integrating services and other scheduling and performance rules. The ISO needs a stakeholder process to design a transition out of PIRP. As large numbers of PIRP resources are expected in the coming years, the ISO should immediately address this issue.

Cross-Reference: This initiative will be discussed in FERC Order 764 market changes (see Section 9.1).

13.21 Unit Commitment and Price Formation Improvements

SCE noted in its comments: on the 2011 draft catalog that, 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.