2013 Stakeholder Initiatives Catalog

as of October 3, 2013

Prepared by

Market and Infrastructure Development

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Stakeholder Initiatives Catalog

1 Introduction

The *Stakeholder Initiatives Catalog* 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. As noted in the opening paragraph of the

Completed Initiatives section (see Section 0), this catalog specifically tracks policy changes and these stakeholder initiatives are considered completed when the stakeholder process ends (and typically results in the ISO's Board of Governors accepting the proposal). Other documents such as the Master Stakeholder Engagement Plan will track additional processes such as tariff development and implementation.[1] For more detailed scheduling and milestones for policy projects, see the Projected Stakeholder Initiative Milestones documents.[2]

Both market design and infrastructure and planning initiatives are listed together. This 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 0:

[1] Available at: http://www.caiso.com/Documents/MasterStakeholderEngagementPlan.pdf
[2] Available at: http://www.caiso.com/Documents/ProjectedStakeholderInitiativeMilestones.pdf

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 0:

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.

Section 0:

Completed Initiatives – Lists initiatives completed thus far in calendar year 2013.

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 non-discretionary category reflects the ISO's responsibility to ensure the integrity of the ISO markets and grid reliability as well as prior commitments made (i.e., to the ISO's Board of Governors). 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

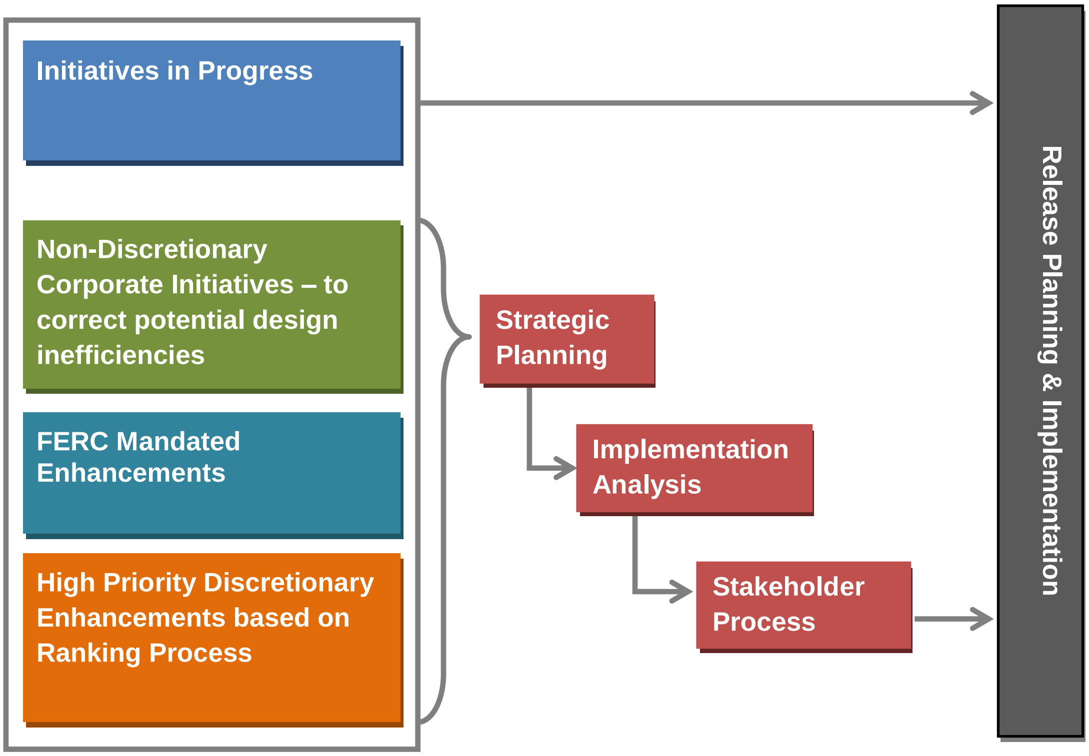
The *in progress* status code may be combined with any of the other three codes to show that a stakeholder process has begun and likely a webpage exists on the ISO stakeholder processes website.[3] For example, "I, F" indicates that a FERC-mandated initiative is currently going through a stakeholder 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. Though the FERC-mandated and non-discretionary initiatives are not open for stakeholder ranking, the latter is used sparingly and we prefer to work with stakeholders to determine priorities. Nonetheless, stakeholder comments are welcome and indeed may be necessary in making special requests to the FERC such as extensions of time. A more detailed description of the ranking processes is provided below.

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

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.

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[4]. 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

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

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.

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.

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-January.

Table A: Proposed Timeline for the 2013 Stakeholder Initiative Catalog

Date	Event
Thurs 10/10/13	Stakeholder conference call
Wed 10/23/13	Stakeholder comments due for feedback items 1 and 2 (clarifications and new initiative proposals)
Tue 11/5/13	Post updated draft 2013 Stakeholder Initiatives Catalog and ranking template
Fri 11/22/13	Stakeholder comments due for feedback item 3 (high level ranking)
Tue 12/17/13	Post revised draft 2013 Stakeholder Initiatives Catalog
Tue 1/7/14	Stakeholder conference call
Tue 1/14/14	Post 2013 Stakeholder Initiatives Catalog

We ask stakeholders to use the two comment periods to provide three feedback items as described below.

1. ***Review discretionary initiatives for completeness***. For this item 1, we ask that stakeholders provide in written comments any questions or clarifications for initiatives listed in this version of the catalog. Stakeholders may also note those initiatives deemed no longer relevant and may be marked for deletion or combination with other initiatives. These comments are due October 23.

2. ***Add discretionary initiatives not listed in this version of the catalog.*** For this item 2, 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. We will also accept suggestions to delete initiatives. These comments are due October 23.

3. ***Rank discretionary initiatives.*** A revised catalog will be posted to the ISO website incorporating items 1 and 2 above on November 5. Based on this updated draft, this item 3 asks stakeholders to select a maximum of five market design initiatives and rank them according to the high level prioritization criteria shown in Figure B (a template will be provided). 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 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.

For initiatives already in the deleted category, the ISO will reinstate the initiative if there is a stakeholder request to keep the initiative accompanied by a written justification of why the initiative is a priority. If a discretionary initiative is proposed to be deleted by a stakeholder, the ISO will do so if there are no objections. If there are both proposals to delete and keep a discretionary initiative, the ISO will conservatively keep the initiative but note the opposing comments. These comments are due November 22.

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 and discussion on a call.

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.[5]

2.1 Bid Cost Recovery (BCR) for Units Running Over Multiple Operating Days (I, 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.[6]

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 3.13); (2) bid cost recovery for units running over multiple operating days (Section 2); (3) multi-hour block constraints in the RUC process (Section 4.2); (4) ancillary services substitution (Section 5.1); (5) exports of ancillary services (Section 12.5); and (6) over-collection of transmission losses (Section 12.9). May also be considered in concert with Multi-Day Unit Commitment in the IFM (see section 2.4).

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

[6] 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.

2.2 Full Network Model (I, N)

Through this initiative, the ISO will expand its full network model to improve reliability and market solution accuracy, consistent with FERC and NERC recommendations following the September 8, 2011 southwest power outage. Through this initiative, the ISO will expand the modeling of the electrical system (i.e., network model) outside of its footprint so that the electrical flows throughout the Western Interconnection can be modeled. More accurate modeling will allow the ISO to better reflect and more consistently enforce constraints between the day-ahead and real-time markets. This should reduce the incidences of infeasible schedules, including physical and virtual schedules, which result in real-time congestion offset charges. The major objectives of the initiative are to enhance: 1) loop flow modeling; 2) security analysis; 3) representation of high voltage direct current transmission; and 4) outage analysis and coordination.

2.3 Marginal Loss Surplus Allocation Alternative Approaches (D)

Since the start of the new ISO market design, allocation of marginal loss surplus has been based on measured demand. This methodology was accepted by FERC in the MRTU Order dated September 21, 2006.[7] In filed comments on the ISO MRTU Tariff, PG&E had concerns about the accepted methodology and suggested an alternative approach to allocate marginal loss surplus. The ISO agreed to study alternatives and published analyses in April 2007 and October 2010. The April 2007 report found that allocation based on measured demand was within the bounds of alternative methodologies.[8] Using data from the first year of operation after the start of MRTU, the October 2010 report found that allocation based on measured demand did not lie within the bounds of alternative methodologies.[9] Based on these results, the ISO agreed to further analyses using "data covering the period after April 1, 2010, which will further inform the stakeholder process."[10] To inform the process, the ISO aims to release an update to the October 2010 report before the end of 2014. Therefore, a stakeholder process will include analyzing the conclusions of this report and then formulating changes to the current allocation methodology, if appropriate.

Status: The ISO aims to release an analysis on alternative marginal loss surplus allocation methodologies by the end of 2014.

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[7] California Independent System Operator Corp., *Order Conditionally Accepting the California Independent System Operator's Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade*, Docket Nos. ER06-615-000, et. al., September 21, 2006.
[8] Available at: http://www.caiso.com/2781/27817949719e0.pdf
[9] Available at: http://www.caiso.com/2828/2828977521d30.pdf
[10] *Ibid,* p. 4.

2.4 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.[11]

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.

Cross-Reference: May also be considered in concert with Bid Cost Recovery for Units Running Over Multiple Operating Days (see Section 2).

2.5 Multi-Stage Generator Bid Cost Recovery (BCR) (D)

The ISO recently filed a proposal with FERC resulting from the Renewable Integration Market and Product Review and Bid Cost Recovery Mitigation Measures detailing 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 could be refined further than the methodology used by the current

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

approach. This initiative would further refine the allocation of costs between the day-ahead and real-time markets for multi-stage generators committed in different configurations in the two markets.

Cross-reference: This initiative would provide an enhancement to the ISO' Lowering the Energy Bid Floor and Changing the Bid Cost Recovery Methodology with Additional Performance Based Refinements proposal filed with FERC on September 25, 2013. [12]

2.6 Regulatory Must-Run Pump Load (D)

This initiative was 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, 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.

[12] http://www.caiso.com/Documents/Sep25_2013TariffAmendment-RenewableIntegrationMarket-ProductReviewPhase1_ER13-2452-000.pdf

3 Real-Time Market

The real-time market consists[13] 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.[14]

3.1 Bidding Rules (D)

This initiative would re-evaluate current rules that allow resources unrestricted flexibility to submit energy bid prices to the real-time market that are different from the prices submitted to the day-ahead market. It would also re-evaluate the current rules that allow resources unrestricted flexibility to submit different energy bid prices across hours in the real-time market. These potential changes would be modeled after bidding rules used by the other ISOs and would potentially improve the consistency between the day-ahead and real-time markets and would further increase safeguards against market manipulation.

3.2 Contingency Modeling Enhancements (I, N)

This initiative is meant to be an umbrella initiative to address various real-time operational issues with the goal of reducing exceptional dispatch (see cross-references below). There are several initiatives in the catalog that may be interrelated, interdependent, or could be addressed simultaneously through a single solution. Whether a single solution is appropriate may also depend on the solution. The underlying issues which cause exceptional dispatch may be reduced via modeling additional constraints, adding or modifying existing processes, or through new products. In other words, considering some of these initiatives in isolation will be less efficient than a holistic approach.

Cross-reference: Previously titled “Additional Constrains, Processes, or Products to Address Exceptional Dispatch,” which was highly ranked in the 2012 stakeholder initiative catalog process. This initiative is an umbrella initiative that will initially address as a priority the need for 30 minute reserve capacity (see Section 13.1).

[13] Under FERC Order No. 764, the real-time market will consist of the real-time unit commitment (RTUC) which produces financially binding 15-minute energy schedules, 15-minute A/S and LMPs, short-term unit commitment (STUC), and the real-time dispatch (RTD) which produces financially binding 5-minute dispatches and LMPs. The real-time market also includes a process to accept hourly schedules from imports and exports that will become financially binding in RTUC.

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

3.3 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.

3.4 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 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.

3.5 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.

3.6 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.

3.7 Extended Pricing Mechanisms (D)

The objective of this initiative is to explore extended pricing mechanisms to either incorporate non-priced constraints into the LMP or to reduce uplifts. In the first option, the primary goal is to incorporate non-priced constraints into the LMP. An example of a non-priced constraint is the minimum online commitment (MOC) constraint such as the G-217 and G-219 operating procedures in the day-ahead market. 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. By incorporating these non-priced constraints, uplift costs may be reduced. In contrast, the second option would have as its object function minimizing uplift costs.

An example of an extended pricing mechanism is the Midwest ISO's proposed "extended LMP pricing." FERC has conditionally approved the use of extended LMP pricing for the Midwest ISO.[15] 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.

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 day-ahead regional procurements of the flexible ramping product (see Section 3.1).

3.8 Flexible Ramping Product (I, N)

The flexible ramping 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 flexible ramping 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

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

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.

The ISO proposes to allocate the costs for this product 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 completed in 2012.

Status: The ISO has delayed the development of this product to Q4 2013 until there is greater clarity in the FERC Order 764 Market Changes initiative (see Section 12.6).

Cross-reference: The flexible ramping 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. Furthermore, the ISO plans to address the Multi-hour Block Constraints in RUC initiative as part of the flexible ramping product (see Section 4.2). This initiative may also address some of the underlying issues which cause real-time imbalance energy offset and real-time congestion offset (see Section 3.9)

3.9 Mitigating Transient Price Spikes, Real-Time Imbalance Energy Offset (RTIEO) / Real-Time Congestion Offset (RTCO) (D)

This initiative was suggested by PGE and SCE (10/10/12) but uses PGE's title.

Language suggested by PGE: "Market volatility has increased significantly in the real-time market, which can drastically increase RTIEO and RTCO costs. Of particular concern are price spikes which occur in one or two real-time intervals resulting from modeling imperfections and for which no action is taken by operators in response. These pricing aberrations increase cost without appearing to serve a market efficiency purpose. This initiative would develop effective near, and midterm, solutions to mitigate these situations."

Language suggested by SCE for similar initiative entitled "Economically Disconnected Price Spikes." "High real-time (RT) price volatility has persisted since the start of Market Redesign Technology Upgrade (MRTU) despite regular identification as a key market issue. The CAISO continues to observe real-time prices spikes of significant frequency and magnitude even after recommendations for improvements in the 2009, 2010, and 2011 CAISO Annual Report on Market Issues and Performance.[16] Factors that likely contribute to economically disconnected RT prices include, but are not limited to, modeling issues (e.g. loop flow), market structure issues (e.g. Hour Ahead Scheduling Process sell off), convergence bidding, market power mitigation, and resource deviation within 5-min RT intervals."

"SCE believes that economically disconnected price spikes have significant impacts to the market, are not indicative of an efficient market, and have caused over half a billion dollars in uplift costs since the start of MRTU.[17] SCE believes that an initiative to improve the RT prices by reducing the frequency and magnitude of non-economic RT price spikes should begin immediately. Contributing factors to economically disconnected price spikes should be identified and evaluated, and subsequently remedial measures must be implemented."

Status: The ISO believes that there are four efforts that also seek to address this issue. The first is lowering the transmission constraint relaxation parameter used in the scheduling run of the real-time dispatch.[18] The change to the $5,000 parameter should decrease real-time constraints and thus real-time congestion offset costs. More broadly, the completed FERC Order 764 market changes initiative[19] seeks to create a 15 minute real-time market, which will address the discrepancy created by the current hour-ahead scheduling process. Aside from these completed initiatives, the flexible ramping product initiative[20] will lessen real-time price spikes due to a shortage in ramping capability. In additional, the in progress Full Network Model initiative is planned to make modeling improvements in the day-ahead to improve convergence between day-ahead and real-time modeled conditions. This would include the authority to address day-ahead unscheduled flows or parallel flow effects. The ISO can also address tiered

[16] 2011 Annual Report on Market Issues & Performance, Executive Summary, Recommendations, Page 16: "highlighted the lack of price convergence in the ISO markets" and "recommends that the ISO remain committed to addressing the underlying causes of price divergence."
2010 Annual Report on Market Issues & Performance, Executive Summary, Recommendations, Page 11: "[Addressing] Real-time price spikes and price divergence… should represent the highest priority for the ISO in terms of improving current market performance."
2009 Annual Report on Market Issues & Performance, Special Revised Executive Summary, Recommendations, Page 20: "Since the first few months of the new market, one of DMM's major recommendations has been to address the systematic divergence between dispatches and prices in the hour-ahead and real-time markets."
Link:
http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

[17] Since the start of MRTU in April 2009, CAISO has incurred roughly $575 million in RTIEO and RTCO uplift costs. See chart on slide 16 in the September 12, 2012 Market Performance and Planning Forum Presentation: http://www.caiso.com/Documents/Agenda_Presentation-MarketPerformance_PlanningForum09122012.pdf.

[18] http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionConstraintRelaxationParameterChange.aspx

[19] http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx

[20] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

and/or voltage level based relaxation parameters, reevaluate price corrections that trigger events/criteria and lastly, consider quality versus timeline for price corrections.

Cross-Reference: FERC Order 764 market changes initiative (see Section 12.6), the flexible ramping product (see Section 3.1) and Full Network Model (see Section 2.2).

3.10 Multi-Stage Generation Transition Costs (D)

This initiative would explore rule changes to more fully and accurately specify multi-stage generator costs to transition between configurations. The ISO and stakeholders examined changes to the definition of transition costs as part of the "Commitment Cost 2012" stakeholder initiative that resulted in various tariff changes proposed to go into place in November 2013. That initiative preliminarily explored transition costs rule changes that would be different than the current approach in which allowable transition costs are only limited by heuristics based on configurations' start-up and minimum load costs. The consensus of stakeholders then was these rule changes should be deferred until market participants gained experience with the multi-stage generator functionality.

3.11 Regional Flexible Ramping Product (D)

The ISO plans to restart the Flexible Ramping Product initiative in Q1 2014. The flexible ramping product is a market based approach to address to address operational challenges that result from insufficient ramping capability to meet interval changes between 5-minute dispatch and uncertainty of load and supply. The flexible ramping product will enhance the existing flexible ramping constraint by positioning units to support upward and downward system requirements in the day-ahead market, 15-minute market, and 5-minute dispatch. The product will allow economic bidding in the day-ahead market and align the cost allocation with the ISO cost allocation guiding principles.

The regional flexible ramping product initiative would be a separate initiative and enhancement the flexible ramping product design. It would establish a regional flexible ramping requirement and cost-allocation in order to ensure that enough flexible ramping was procured to meet regional needs and not just at a system level.

3.12 Stepped Transmission Constraint (F)

The ISO would consider enhancements to the structure of scheduling transmission constraint relaxation parameter. The initiative would evaluate whether the performance of the transmission relaxation parameter could be improved if the ISO were able to calibrate it at different levels depending on either level of constraint relaxation, voltage level of constraint, or the system impact of the constraint.

3.13 Two-tier Rather Than Single Tier Real-Time Bid Cost Recovery (BCR) Allocation (I, 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.[21]

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 3.13); (2) bid cost recovery for units running over multiple operating days (Section 2); (3) multi-hour block constraints in the RUC process (Section 4.2); (4) ancillary services substitution (Section 5.1); (5) exports of ancillary services (Section 12.5); and (6) over-collection of transmission losses (Section 12.9). This initiative will likely be discussed under the broader cost allocation overall market review (see Section 13.2).

[21] 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 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.[22]

4.1 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.

4.2 Multi-Hour Block Constraints in RUC (I, 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.[23]

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

[23] 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: The ISO plans to address this issue under the Flexible Ramping Product initiative because of the proposed integration of the integrated forward market and residual unit commitment (see Section 3.1). 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 3.13); (2) bid cost recovery for units running over multiple operating days (Section 2); (3) multi-hour block constraints in the RUC process (Section 4.2); (4) ancillary services substitution (Section 5.1); (5) exports of ancillary services (Section 12.5); and (6) over-collection of transmission losses (Section 12.9).

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.[24]

5.1 Ancillary Services Substitution (I, 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.[25]

5.2 Blackstart, Voltage support, 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. In June 2013, FERC issued an order stating, "CAISO stated that it would initiate a stakeholder process on the market-based procurement of voltage support outside of exceptional dispatch once it had obtained several additional months of data. After nearly three additional years of market operation, we expect that CAISO has sufficient information to reinitiate the stakeholder process on the market-based procurement of voltage support." 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. Additionally the second phase will address FERC's order to develop market-based procurement of voltage support. This effort will require a stakeholder process, which will be addressed in 2014.

Cross-Reference: Previously titled, "Blackstart and System Restoration"

[24] http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx
[25] 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.

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

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 3.13); (2) bid cost recovery for units running over multiple operating days (Section 2); (3) multi-hour block constraints in the RUC process (Section 4.2); (4) ancillary services substitution (Section 5.1); (5) exports of ancillary services (Section 12.5); and (6) over-collection of transmission losses (Section 12.9).

5.3 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.

5.4 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.

5.5 Voltage Support Procurement (D)

This issue involves 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.

Cross-reference: This initiative will be subsumed into Blackstart, Voltage support, and System Restoration (See section 5.2).

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.[26]

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.

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

6.3 Insufficient CRR Hedging (D)

This initiative was suggested by CDWR (10/10/12). "One of the biggest improvements of the Market Redesign and Technology Upgrade (MRTU) is that a Market Participant could schedule independently its loads and resources using MRTU's Integrated Forward Market (IFM) feature. The biggest setback of this MRTU improvement is that it is impossible to obtain an adequate hedge of congestion rents resulting from imbalanced schedules using the CAISO's current balanced hedging mechanism, i.e. Congestion Revenue Rights (CRR). The CRR is a balanced product, the CAISO's current CRR design only allows CRRs being requested between resources and loads. The CRR Upper Bound (UB) feature further restricts the amount of CRRs that a Market Participant (MP) can request based on the MP's historical load."

"In order to be compliant with FERC Order 741 – Minimum Credit Requirement for CRRs, CDWR continuously monitors congestion rents resulting from CDWR's (imbalanced) schedules and CRR revenues of CRRs that CDWR owns. For 2011, CDWR's congestion rents were three times larger than the CRR revenues. We would like to mention that CDWR almost maxes out its CRR allocation and CDWR's participation in the CRR auction is not a viable solution to provide additional hedge. The difference between the congestion rents value and CRR revenues value is the result of congestion rents for the excess generation (when CDWR generation exceeds CDWR load – mostly during On-Peak periods) and congestion rents for the excess load (when CDWR load exceeds CDWR generation – this occurs mostly during Off-Peak periods). Among these two sources of congestion rents that cannot be hedged with CRRs, the congestion rent generated by the excess load is the most significant (95% of the entire cumulated excess generation and excess load congestion rents). The Power Point presentation attached to this document shows, conceptually, how the congestion rents resulting from imbalanced schedules could result in three times higher congestion rents than those resulting from balanced schedules."

6.4 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.

6.5 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.

6.6 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 12.6).

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 CRR sub-LAPs to the available locations for convergence bidding.

7.2 Convergence Bidding Clawback (D)

The following tariff provision excludes CRR revenue adjustments (clawback rule) on the LAPs and generation trading hubs: “For each CRR Holder subject to this Section 11.2.4.6, for each hour, and for each Transmission Constraint binding in the IFM, HASP, or RTD, the CAISO will calculate the Flow Impact of the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder, excluding Virtual Awards at LAPs and generation Trading Hubs.” LAPs and trading hubs are excluded from the rule because they are considered too large for a market participant to profitably increase CRR payments from convergence bids. Due to their smaller sizes, the ISO Department of Market Monitoring recommends that the exemption of the VEA and SDG&E LAP be removed from the CRR revenue adjustment rule outlined in tariff section 11.2.4.6.

7.3 Real-time Congestion Uplift Cost Allocation (D)

This initiative would examine potential changes to the allocation of real-time congestion revenue imbalance uplift. Real-time congestion revenue imbalance is caused by scheduled day-ahead flow exceeding real-time scheduled flow on constraints that bind in real-time. When this occurs, out-of-market payments are received by schedules that increased the flow on the constraint in the day-ahead market, but are reduced in real-time. The uplift is allocated to measured demand. This initiative would explore allocating the uplift to physical and virtual schedules in proportion to the quantity of out-of-market congestion payments received by physical and virtual schedules.

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 Resource Adequacy Criteria 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 be formulated in the Joint Reliability Framework (see Section 8.2). 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 Use-limited Resource Adequacy Criteria and Must Offer Obligations (see Section 8.6).

8.2 Joint Reliability Framework (D)

This initiative was previously referred to as the "Multi-year Forward Reliability Capacity Pricing Mechanism" in the 2012 Market Design Initiatives Catalog. The ISO initially proposed a multi-year forward capacity market; however, based on feedback from the CPUC, the ISO has moved forward instead with the Joint Reliability Framework initiative. The staffs of the California Public Utilities Commission and the California Independent System Operator Corporation proposed for consideration a Joint Reliability Framework that would combine multi-year resource adequacy obligations for load serving entities with a multi-year market-based ISO backstop capacity procurement mechanism. The Joint Reliability Framework initiative would address the necessary changes to move forward with the following proposed items:

(1) Augment the existing year-ahead resource adequacy procurement obligations for all load serving entities, including electric service providers and community choice aggregators, by establishing procurement obligations two and three years prior to a delivery year;

(2) Develop an ISO-run capacity auction (the Reliability Services Auction) to provide two functions. First, replace the ISO's existing backstop capacity procurement mechanism, which expires in 2015, in order to cure deficiencies in resource adequacy demonstrations. Second, provide a voluntary platform for LSEs to procure additional forward capacity beyond that which they procure bilaterally; and

(3) Provide an annual long-term reliability planning assessment, focused on the four to ten-year forward period, with information on both the expected fleet (installed capacity) and contracted fleet (procured capacity). The assessment will provide market participants and regulators with better information about net open positions, expected demand, and expected supply.

8.3 Seasonal Local RA Requirements (D)

Seasonal local RA requirements, as an alternative to the annual requirement based on the summer peak, was proposed and discussed extensively in the CPUC's resource adequacy phase 2 proceeding for compliance year 2012 (R.09-10-032). Supporters of a seasonal requirement incorrectly argued that a monthly or seasonal local RA requirement will be lower than the August peak load currently used in setting the year-ahead obligation. In fact, according to ISO analysis, the need for RA resources would be increased in the non-summer months to account for the performance of most planned maintenance on transmission facilities during the off-peak periods. Furthermore, a monthly or seasonal local RA requirement cannot be implemented without significant burden to the ISO to perform many additional deliverability studies in order to assure that such resources are actually deliverable in each month or each season and an increase in the local RA requirement on a monthly or seasonal basis will affect all load serving entities and will likely increase their cost of RA procurement, without providing commensurate or necessary enhancement to system reliability. At the conclusion of the proceeding, the CPUC declined to adopt a seasonal LCR for 2012.

8.4 Standard Capacity Product Enhancements (D)

This initiative combines separate but related comments from SCE and PGE but uses SCE's proposed title (10/10/12).

SCE comments: "Since implementation of the CAISO's Standard Capacity Product (SCP) Phase I initiative on January 1, 2010, various issues have arisen concerning substitution requirements, incentive payments, and rule clarifications that were not addressed in Phase II of the CAISO's SCP initiative. The scope of Phase II was limited given that it sought to incorporate only non-dispatchable resources within the framework of the SCP requirements beginning January 1, 2011. These issues must be addressed at the earliest opportunity to avoid costly over-procurement of resources, eliminate incentive payments for resources on planned outage, and add clarity to the rules for situations that were not contemplated when the initial SCP requirements were developed. SCE recommends that enhancements to the SCP program be addressed as a distinct stakeholder initiative, although the item could be rolled into Phase III of the CAISO's SCP initiative which seeks to incorporate Demand Response resources under the SCP requirements."

PGE comments: "In the current formula for calculating SCP non-availability charges, the same penalty cost is used across all months. Specifically, the non-availability charge rate is set at the Monthly CPM Capacity Payment price, which is calculated by multiplying the annual CPM Capacity Payment price by a uniform monthly shaping factor of 1/12.[27]"

"Given the reliability impact of forced outages varies significantly by month, the penalties and payments should reflect the true market value of availability resulting in more reasonable price signals to participants. This initiative would develop monthly charge adjustment factors reflecting the relative value of availability to the CAISO that would be used to calculate different monthly SCP rates."

Cross-reference: This initiative may be addressed under Use-limited Resource Adequacy Criteria and Must Offer Obligations (see Section 8.6).

[27] See CAISO Tariff, Schedule 6 of Appendix F.

8.5 Standard 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) resource adequacy resources in the near future.

Cross-Reference: This initiative will be addressed under the Use-limited Resource Adequacy Criteria and Must Offer Obligations initiative (see Section 8.6).

8.6 Use-limited Resource Adequacy Criteria 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 Resource Adequacy Criteria 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 for Distributed Energy Resources 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 Expansion of Metering and Telemetry Options initiative (see Section 11.5). This initiative will also address the Standard Capacity Product for Demand Response (SCP III) initiative (see Section 8.5) and the Standard Capacity Product Enhancements initiative (see Section 8.4). Must offer obligations for resources with flexible attributes are discussed under the Flexible Resource Adequacy Criteria and Must Offer Obligations initiative (see Section 8.1).

8.7 Voluntary Demand Response Auction (D)

This initiative would develop a voluntary preferred resource auction to assist LSEs in their procurement of preferred resources that satisfy both CPUC local capacity procurement requirements and the ISO's local capacity reliability needs. The auction would work in concert with the CPUC's resource adequacy program timelines, providing sufficient time for LSEs to bilaterally procure additional local RA capacity that is needed to fulfill their local capacity procurement obligations.

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 EIM Transmission Access Charge (D)

The initial EIM implementation will not include a transmission charge between the ISO and EIM Entities used to support EIM transfers. During the EIM stakeholder initiative, the ISO comitted to further consider the design of transmission service during the first year of operation. The initiative will be informed by actual EIM operational experience.

In the EIM Draft Final Proposal, the ISO discussed potential design alternatives for transmission service. The alternatives are:

1. Reciprocity in Use of Transmission Made Available by Rights-Holders in EIM Entities

2. EIM Transmission Access Charge

3. Transfer Charge as a Minimum Shadow Price:

4. Transmission Access Charge Applicable to Load and Wheeling

The ISO will collect operational data that will inform the selection from the above alternatives or other options developed through the stakeholder initiative.

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 Deliverability Network Upgrade Planning Criteria (D)

This initiative was suggested by the Bay Area Municipal Transmission Group (BAMx) (11/1/12). According to BAMx:

In this particular case the concern is that the current Deliverability Network Upgrade Planning Criteria may be driving costs that are not commensurate with the benefits. BAMx suggested that the CAISO and CPUC, along with other stakeholders, should work together in this proceeding to align the CAISO's deliverability assessment criteria with the CPUC's least-cost, best-fit long-term resource planning and procurement oversight.

Status: Since the publication of the previous 2013 stakeholder initiatives catalog, the ISO has expended considerable effort in response to this suggestion from BAMx. The ISO provided a generator interconnection and deliverability study methodology training session on December 4, 2012. A presentation was posted on November 29, 2012, and the training session was held during a stakeholder call on December 4, 2012. The training provided a forum for market participants and other interested parties to gain an understanding of the ISO's generation interconnection and deliverability study methodology. Stakeholders were given an opportunity to provide written comments on the methodology. The written comments that were received were posted on December 31, 2012. The ISO's responses to those written comments were posted on March 4, 2013. The materials discussed above are available at the following ISO web page: http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

The ISO held a stakeholder call on July 25, 2013 to discuss a technical paper on the generator interconnection and deliverability study methodology. The technical paper was posted on July 2, 2013 and provided detailed, realistic examples of applying the deliverability methodology and elaborated on the December 4, 2012 training session. The ISO posted a presentation on July 23, 2013 and held a stakeholder call on July 25, 2013. Stakeholders were given an opportunity to provide written comments on the technical paper. On August 22, 2013, the ISO posted on the ISO website the written comments that were received from stakeholders. The ISO's responses to those written comments are scheduled to be posted on October 3, 2013. The materials discussed above are available at the following ISO web page: http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

Based on positive feedback received from stakeholders regarding the content of the July 2, 2013 technical paper, the ISO believes that the transparency concerns previously expressed by some stakeholders regarding the ISO's deliverability methodology have been addressed. Further, the ISO believes that there are no fundamental flaws with the ISO deliverability assessment methodology and that the methodology provides reasonable and intuitive study results. Some stakeholders such as BAMx, who submitted this topic to the 2013 stakeholder initiatives catalog, have commented that the methodology is overly severe and potentially leads to unnecessary ratepayer funded transmission development. However, these comments are based on study results prior to the implementation of the generator interconnection and deliverability allocation procedures tariff (also known as "GIDAP"). This concern is based on previous cluster studies that had excessive amounts of generation in the interconnection queue. Under GIDAP, major transmission upgrades are addressed through the transmission planning process based on renewable generation portfolios developed through the CPUC process. It is not expected that Cluster 5, which is the first cluster studied under GIDAP, will identify the need for any major ratepayer funded transmission upgrades. Therefore, at this time, the ISO believes that the general issues raised by a few stakeholders do not warrant the allocation of considerable resources needed to embark on a lengthy stakeholder process to reevaluate, recreate or fine tune the generator interconnection and deliverability study methodology. The ISO believes that such an effort is not warranted when there are other pressing initiatives that are higher priority.

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

The ISO is committed to continuously review potential enhancements to its Generator Interconnection Procedures ("GIP") to reflect changes in the industry and to better accommodate the needs of generation developers. As a demonstration of this commitment, the ISO has conducted a series of stakeholder processes over the past several years to improve the GIP. These include Generation Interconnection Process Reform ("GIPR") held in 2008-09, Generation Interconnection Procedures Phase 1 ("GIP 1") in 2010, Generation Interconnection Procedures Phase 2 ("GIP 2") in 2011 and early 2012, and Generation Interconnection Procedures Phase 3 ("GIP 3") in 2012.

GIP 3 was started in early 2012, but was later deferred while the generator project downsizing initiative was pursued. In GIP 3 the ISO solicited stakeholder comments on the relative priority of issues that should be considered, on generator project downsizing as well as on a couple dozen other topics. 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: On April 8, 2013 the ISO launched the Interconnection Process Enhancements ("IPE") initiative as the successor to GIP 3 in order to begin a new cycle of interconnection process enhancements. The ISO launched the IPE initiative with the issuance of a scoping proposal on April 8. The scoping proposal accomplished two steps: first, it assembled a comprehensive list of potential GIP-related topics for consideration in the IPE initiative; and second, it selected 12 topics from the comprehensive list of topics for proposed inclusion in the scope of this initiative. Based on stakeholder feedback regarding the April 8 scoping proposal, the ISO added three topics to the scope of the IPE initiative and posted an issue paper on June 3 addressing the expanded scope comprising a total of 15 topics.

While the June 3 issue paper was a conventional issue paper for some of the 15 topics in scope, it served as a straw proposal paper for others. Specifically, for the seven topics addressing queue management issues (*i.e.*, topics 6-12), the ISO offered straw proposals in the June 3 paper. For the remaining eight topics (*i.e.*, topics 1-5 and 13-15), the ISO was not yet prepared to offer proposals in the June 3 issue paper and instead provided further analysis of the issues and suggested potential ideas and options for stakeholder consideration. Following publication of the June 3 issue paper and receipt of stakeholder comments, the ISO posted a draft final proposal for topics 6-12 on July 2. The ISO Board of Governors approved the proposals on topics 6-11 at the September meeting. The ISO made a subsequent filing of the associated tariff changes with FERC. As a result, topics 6-11 will not be addressed in subsequent papers in this initiative as work on those topics has concluded with the filing to FERC.

Based on written stakeholder comments received on the June 3 paper, on July 18 the ISO posted a straw proposal for topics 1-5 and 13-15. In that paper, the ISO offered straw proposals on three topics (topics 1-3)[28] relating to the sizing and structuring of projects in the interconnection queue. The ISO also offered a straw proposal for topic 15 (inverter/transformer changes and the material modification process) in the July 18 paper; however, implementation of the proposal will be through the business practice manual change process rather than through tariff changes. Where needs for tariff changes have been identified under topic 15, the ISO has incorporated those into the proposals for topics 1 and 2. The July 18 paper also addressed the remaining four topics within the scope of this initiative (*i.e.*, topics 4, 5, 13, and 14)[29] but the ISO was not yet prepared to offer straw proposals for these four topics. Nevertheless, the paper provided additional analysis of these topics based on stakeholder comments received and, for some topics, offered options for stakeholder consideration.

At the time the July 18 straw proposal was published, the ISO had expected to resolve topics 1-3 in the Fall of 2013 and accordingly targeted the December meeting of the ISO Board for presentations of its final proposals on these three topics. However, this expectation has been modified somewhat. The ISO is now planning to present its proposals on topics 1 and 2 at the November 7-8 rather than the December meeting of the Board. For topic 3, the ISO has

[28] These three topics are: (1) future downsizing policy; (2) disconnection of the completed phase(s) of a project due to failure to complete a subsequent phase; and (3) clarification of tariff and GIA provisions related to dividing up GIAs into multiple phases.

[29] These four topics are: (4) improvement of the Independent Study Process; (5) improvement of the Fast Track Process; (13) clarification of the timing of transmission cost reimbursement; and (14) distribution of forfeited funds.

decided to take more time to develop a draft final proposal. Thus, the ISO is targeting an early 2014 Board meeting for presentation of its final proposals on topics 3-5 and 12-14. The ISO is continuing to work with stakeholders to address the remaining topics and will issue a straw proposal paper on these topics in the October 2013 and a draft final proposal in December 2013.

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 seeks input from stakeholders on the priority of this possible topic relative to other topics in this catalog.

10.4 Affected Systems (D)

On August 5, 2013, the ISO issued a market notice announcing the start of a new stakeholder initiative titled "Affected System Impacts of Generator Interconnection." The goal of this topic to add further detail to the ISO's business practice manual for generator interconnection procedures on the processes and principles for addressing "affected system" impacts. The processes and principles were described in a paper that was posted on August 5, 2013. In this initiative, the ISO will clarify existing practices for situations where generator interconnection to the ISO controlled grid affect neighboring systems and where generator interconnection to facilities outside of the ISO controlled grid affect the ISO system. The ISO held a conference call on August 23, 2013 to discuss the paper. A presentation for the call was posted on August

21, 2013. Written stakeholder comments were received on September 12, 2013. On September 16, the ISO posted the written stakeholder comments that it received. The schedule calls for the ISO to post a second paper on October 9, 2013, which will include proposed language for the ISO's business practice manual. The materials discussed above can be found at the ISO's web site at: http://www.caiso.com/informed/Pages/StakeholderProcesses/AffectedSystemImpacts_GeneratorInterconnection.aspx.

In the written comments that were received on the August 5, 2013 paper, several stakeholders requested that the ISO significantly expand the scope of this initiative to include fundamental changes to the current processes and principles, which would require amendments to the ISO tariff in addition to changes to the business practice manual. The ISO believes that it is important to document the current processes and principles in the business practice manual. The scope suggested by some stakeholders would require significant resources and a lengthy stakeholder process to address. Before the ISO will consider expanding the scope of the affected systems initiative, the ISO believes that it should obtain stakeholders' views on the priority of this possible expanded scope relative to other topics in this catalog. In the meantime, the ISO will continue to work on documenting the existing processes and principles and putting them in the business practice manual. Stakeholders are encouraged to "vote" on how important this potentially expanded topic is relative to other topics under consideration, with the understanding that there may be trade-offs depending on which topics are eventually pursued. Stakeholder initiatives place demands on both the ISO's resources and stakeholders' resources, and there is finite capacity to address issues. Stakeholder suggestions regarding the scope of policy work on affected systems issues represent a major undertaking that, if chosen, would dominate transmission policy resources for a significant period of time.

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.

Status: The ISO has released an issue paper and stakeholders have provided comments. The ISO suspended work on this initiative in 2013 because of competing priorities but plans to restart this initiative in the near future.

11.2 Aggregated Pumps and Pump Storage (D)

The ISO had designed its proxy demand resource (PDR) to allow direct participation for a single resource to both schedule demand and bid load curtailments as an integrated bid. PDR bids are co-optimized with energy and ancillary services in both the day ahead and real-time markets to determine the best utilization of the resource. While the PDR product provided demand response resources with full comparable functionality to that of a generator in the ISO's markets, CDWR commented (10/10/12) that PDR did not fully meet the needs of participating loads.

In 2010 the ISO conducted a preliminary analysis of how the multi-stage generator (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, broad stakeholder 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.

11.3 Electric Vehicle Charging Station Demand Response Product (D)

This effort reflects the ISO's continuing efforts to incorporate non-generating resources into the ISO's markets and provides these resources more opportunities and options for participation. NGR/PDR will combine the features of the ISO's current non-generating resource (NGR) model and the proxy demand resource (PDR) product. The combination will allow non-generating resources (which may be provided by third party aggregators) the capability to provide all ISO products including energy, spinning reserve, non-spinning reserve, and regulation service. In addition to the current use of a baseline or statistical method, the NGR/PDR option could allow direct measurement of response if the resource is capable of such individual metering.

11.4 Exceptional Dispatch Decremental Settlement (N)

This initiative addresses settlement rules for decremental exceptional dispatch energy and shut-down energy (energy from minimum load to shutdown). Currently decremental energy settles at the lower of the LMP, default energy bid, or market bid, and this initiative would look at other potential settlements. The tariff does not specify a price for decremental exceptional dispatch energy when a resource is exceptionally dispatched to shut down from minimum load. Therefore the current practice has been not to charge any price at all. This initiative would explore settlement alternatives.

11.5 Expansion of Metering and Telemetry Options (I, 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 Use-limited Resource Adequacy Criteria and Must Offer Obligations initiative (see Section 8.6).

11.6 Generator Unit Testing (D)

The ISO plans to clarify the tariff to allow bid cost recovery for start-up and minimum load costs for ISO initiated generating unit tests. Following this clarification there may need to be updated rules regarding bid cost recovery if a resource fails a test and to further specify bid cost recovery that should be paid for unit testing. Additionally, this initiative would formalize generating unit testing procedures done by the ISO to ensure reliability.

11.7 Greenhouse Gas Rules (N)

This initiative would address the changes in greenhouse gas compliance obligations in 2015. Currently, only resources with more than 25,000 metric tons of CO_2 emissions per year have a compliance obligation to purchase and submit greenhouse gas allowances to the California Air Resources Board. The ISO includes greenhouse gas costs for these resources in their default energy bids, start-up costs, and minimum load costs. In 2015 the greenhouse gas obligations will extend to natural gas, which will affect resources currently under the minimum threshold. Starting in 2015, the ISO may potentially have to include greenhouse gas costs for resources that emit less than 25,000 metric tons.

11.8 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.”

11.9 Outage Management System Replacement (I, N)

This stakeholder initiative is focused on business process improvements associated with the replacement and consolidation of several outage management systems into a single application. In addition to the changes to outage management applications, the initiative is considering several policy level changes in the way outages are managed and reported. These include replacing Generating Available Data System (GADS) codes with “Nature of Work” categories, designating outages as either Final Approval Required or Final Approval Not Required, creating a new designation of “partial forced” for when a planned outage is changed within the forced outage time frame, and requiring seven days advance notice to receive a planned designation for generation outages.

Status: This stakeholder initiative is currently underway and is being led by the ISO’s operation group. It is expected to be presented to the Board in February, 2014 to allow for planned implementation in the Fall of 2014.

11.10 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.

11.11 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 after August 2012 and before November 2013. 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. This catalog will document a single initiative and cross reference any subsumed initiatives. 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 Bid Cost Recovery Mitigation Measures

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: Presented at the Board of Governors in December 2012 for approval.

Cross-reference: This initiative was originally introduced as part of the Renewables Integration Market and Product Review Phase 1. Further refinements to day-ahead and real-time BCR for multi-stage generators will be addressed separately (see Section 2.5).

12.2 Decremental Bidding from PIRP Resources

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 was addressed under the FERC Order 764 Market Changes initiative (see Section 12.6). Through that initiative, more specific bidding requirements have been developed to address some of the concerns described above.

12.3 Energy Imbalance Market

The EIM will allow interested balancing authorities) throughout the West to voluntarily participate in a real-time imbalance energy market operated by the ISO. The EIM will dispatch economic bids to efficiently balance supply, transfers between the ISO and other EIM Entities, and load within its footprint, providing cost savings, improved renewable integration, and increased reliability.

Status: Presented at the Board of Governors in November 2013 for approval.

12.4 Exceptional Dispatch Mitigation in Real Time

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.

Status: Presented at the Board of Governors in December 2012 for approval.

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

12.5 Exports of Ancillary Services

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: The ISO has filed a motion on April 30, 2013 requesting that FERC determine that the ISO has satisfied the directive.

12.6 FERC Order 764 Market Changes

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. In addition, generators in the Participating Intermittent Resources Program (PIRP) will be allowed to provide decremental bids in order to provide flexible ramping down. This is related to and may fully address decremental bidding from PIRP resources (see Section 12.2). 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.

Issues previously discussed in the Intertie Pricing and Settlement initiative 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 initiative includes decremental bidding from PIRP resources (see Section 12.2). In addition, this initiative served as an umbrella initiative that replaced nine stand-alone initiatives, which are better addressed together and within the context of FERC Order 764. They are: (1) Additional Bid Cost Recovery for Convergence Bidding; (2) Allocation of Intertie Capacity; (3) Allow Virtual Bids on the Interties; (4) Creation of a Full Hour-Ahead Settlement Market; (5) Interchange Transactions after the Real Time Market; (6) Intertie Pricing and Settlement; (7) Real-Time Imbalance Energy Offset; (8) Sub-Hourly Scheduling; and (9) Transition out of the Participating Intermittent Resource Program (PIRP). Moreover, the impact of this initiative may be beneficial to addressing some of the underlying issues which cause real-time imbalance energy offset and real-time congestion offset (see Section 3.9).

12.7 FERC Order 1000 Compliance

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. The ISO subsequently filed revisions to its tariff to comply with the local and regional transmission and cost-allocation requirements of Order No. 1000 on October 11, 2013. On April 18, 2013, the FERC accepted the ISO's compliance filing effective October 1, 2013, subject to the ISO's submission of a further compliance filing. On August 16, 2013, the ISO submitted its filing in compliance with FERC's April 18th Order On Compliance Filing.

The ISO Board of Governors approved the proposal for complying with the interregional requirements of Order No. 1000 on September 13, 2013. The ISO subsequently filed revisions to its tariff to comply with the interregional requirements of Order No. 1000 on May 10, 2013. An order from FERC is pending.

12.8 Load Aggregation Point (LAP) Granularity

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.

Status: The ISO plans to file at FERC by Q1 2014 to remove the compliance obligation to move forward with defining more granular load zones.

12.9 Marginal Loss Surplus Allocation Based on CEC Proposal (I, 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. The FERC obligation is the consideration of the California Energy Commission's proposal on the rebate of loss over-collection for renewable resources.[30]

Status: The ISO has filed a motion on September 27, 2013 that the ISO does not intend to initiation a stakeholder process and requested that FERC determine that the ISO has satisfied the directive.

12.10 Revisions to Price Corrections Requirements

Through its price correction process, the ISO corrects invalid prices consistent with a set of criteria defined in the tariff and in the business practice manual for market operations. The intent of the price correction process is to ensure appropriate prices are used in settlements based on the best assessment of system and market conditions. The ISO has gained three years of market experience since it last evaluated its price corrections procedures. With this additional market experience and through a stakeholder process conducted over the last three months, Management has identified specific refinements to the price corrections processes that will increase the accuracy and certainty of market prices. These refinements include: 1) adjusting

[30] See FERC's 9/21/06 MRTU Order (Docket No. ER06-615-000, *et. al.*) which notes on PP1402: "Further, we direct the CAISO to address additional issues related to the integration of intermittent resource issues, including transmission line loss over collection issues, in Release 2." The "Release 2" list is provided in CAISO's tariff filing starting on page 95 (Docket No. ER06-615-000, *et. al.* filed on February 9, 2006).

the closing time of inter-scheduling coordinator trades; 2) revising the time horizon for price corrections; 3) clarifying the types of processing and publication issues that may require changes in posted prices beyond the typical time horizon; and 4) providing additional communications regarding price corrections. The ISO Board of Governors approved this initiative in September 2013.

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 30 Minute Operating Reserve (I, N)

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

Cross-Reference: This initiative is subsumed into the Contingency Modeling Enhancements initiative (see Section 3.2).

13.2 Cost Allocation Overall Market Review (N)

This initiative will use the seven cost allocation guiding principles developed through a stakeholder process in 2012 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; (2) Consideration of Unaccounted for Energy (UFE) as Part of Metered Demand for Cost Allocation ;(3) Cost Allocation for Regulation; (4) Cost Allocation for RUC; (5) Marginal Loss Surplus Allocation (Section 12.9); (6) PIRP Cost Allocation; and (7) Two-tier Rather Than Single Tier Real-Time Bid Cost Recovery (BCR) Allocation (Section 3.13). 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.[31]

Status: The ISO has revised this initiative and instead of a backward looking review of existing cost allocation methodologies has incorporated the cost allocation principles in all future initiatives in these areas. In addition, a number of existing cost-allocation issues have been addressed as part of the FERC Order 764 Market Changes initiative.

13.3 Data Transparency (D)

This initiative was suggested by Calpine (10/10/12). "The data transparency initiative is not included in the catalog. We continue to believe that this initiative is critical, as market participants – and even the most informed consultants – are entirely unable to replicate the results of the CAISO models. We anxiously await the release of phase 3 information later this year. However, we anticipate that our concerns over information release will not be resolved and that continued focus on this initiative will be required.

13.4 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.

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.

Status: This initiative is subsumed into the Flexible Ramping Product (See Section 3.8). In this initiative the ISO has proposed to retire operating ramp rates and use operational ramp rates for both ancillary services and energy scheduling and dispatch in real time.

[31] 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.

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

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

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

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

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

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