Draft 2015 Stakeholder Initiatives Catalog

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1 Introduction

The *2015 Stakeholder Initiatives Catalog* documents current and proposed policy changes and enhancements to the ISO market design and infrastructure and 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.

This catalog specifically tracks policy changes and 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 4: Residual Unit Commitment – Lists initiatives that mostly affect the residual unit commitment process.

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

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

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

Section 8: Resource Adequacy and Long-Term Supply Sufficiency – Lists initiatives that mostly affect resource adequacy and supply sufficiency.

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

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 12: Completed Initiatives – Lists initiatives completed since the ISO published last year's Stakeholder Initiatives Catalog.

Section 13: Catalog Deletions – Lists initiatives which will be deleted from the next version of the catalog because the initiatives 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 within 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 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; and

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. Initiatives 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

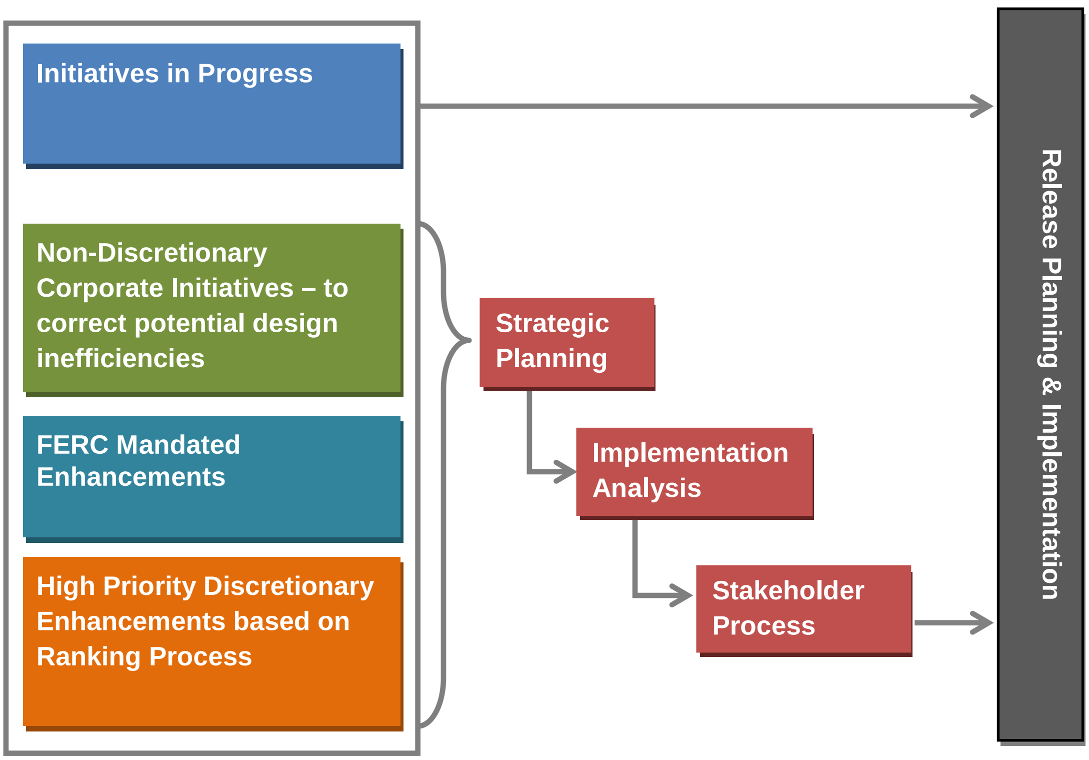
[3] http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx

latter is used sparingly and the ISO prefers 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 for extensions of time. A more detailed description of the ranking processes is provided below.

1.1 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. The ranking process has two potential steps, the high level prioritization and the detailed ranking. The ISO only proceeds to the detailed ranking if the high level prioritization does not provide sufficient clarity on the priority of discretionary initiatives.

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, the ISO grades each initiative's benefit and feasibility under its high level benefit criteria as either "high," "medium," "low," or "none." These 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 are "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	Benefit	Improving Overall Market Efficiency	Significant improvement	Moderate improvement	Minimal improvement	No impact
C	Benefit	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	Feasibility	ISO Implementation Impact ($ and resources)	No Impact	Minimal Impact	Moderate Impact	Significant impact

Detailed Ranking Process

If the high level prioritization does not provide sufficient clarity on the priority of discretionary initiatives, top-ranked 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 Process for Catalog

Table A, below, lists the proposed timeline and process to complete the 2015 Stakeholder Initiatives Catalog. This timeline contemplates that the ISO's high-level prioritizations will provide sufficient clarity on the priority of discretionary initiatives. The ISO will modify this timeline and add an additional step to conduct the detailed ranking based on stakeholder input if it does not.

Table A: Proposed Timeline and Process for 2015 Stakeholder Initiatives Catalog

Date	Event
Oct 1, 2014	Post Draft 2015 Stakeholder Initiatives Catalog.
Oct 9	Stakeholder conference call.
Oct 22	Stakeholder written comments due for the following: • **Questions or clarifications** regarding initiatives listed in catalog. • ***Proposed initiatives not listed in catalog.*** Stakeholders may provide written comments, including a detailed explanation of new initiative, how it may affect market participants and/or reliability or efficiency of market, and when it needs to be addressed. • ***Proposed deletions to initiatives listed in catalog.*** Stakeholders may provide written comments, including detailed explanation of reason ISO should delete an initiative listed in catalog or reason ISO should not delete an initiative it proposes to delete (see section 13.)
Nov 10	Post Revised Draft 2015 Stakeholder Initiatives Catalog that includes ISO's high-level ranking of initiatives.
Nov 17	Stakeholder conference call.
Dec 1	Stakeholder comments due regarding ISO's high-level ranking of initiatives.
Dec 17	Post Draft Final 2013 Stakeholder Initiatives Catalog.
Feb 5-6, 2015	Present 2015 policy development roadmap to ISO Board of Governors.

Stakeholder comments submitted as part of this process should be submitted to shcatalog@caiso.com.

1.3 Update on Last Year's Top Ranked Discretionary Initiatives

This section provides updates on the top discretionary initiatives in last year's stakeholder catalog, the "2013 Stakeholder Initiative Catalog." (The 2013 catalog ranked initiatives to be completed in 2014. The ISO has titled this year's catalog the "2015 Stakeholder Initiative

Catalog" rather than calling it the "2014 Stakeholder Initiative Catalog." This better reflects that it outlines potential initiatives to complete in 2015.)

Last Year's Final Discretionary Rankings
The following five initiatives were the five-highest ranked last year:

1. Review of Convergence Bidding Uplift Allocation
2. Mitigating Transient Price Spikes, Real-Time Imbalance Energy Offset/ Real-Time Congestion Offset
3. Standard Capacity Product Enhancements
4. Modify Resource Adequacy Replacement Rules
5. Extended Pricing Mechanisms

A summary of the status of each of these initiatives is provided below.

1. Review of Convergence Bidding Uplift Allocation - This initiative would evaluate the costs and benefits associated with convergence bidding and potentially implement a different allocation of uplifts due to convergence bidding than the current allocation to measured demand. Load serving entities, in particular, maintain that they should not be allocated costs that are exacerbated by convergence bidding, such as costs related to real-time congestion uplifts.

In 2014, the ISO completed and implemented the "Full Network Model Expansion" initiative that should reduce these real-time congestion uplift costs. It addresses a root cause of these costs by modeling loop flow in the day-ahead market, where previously it was not. It will be prudent to evaluate and understand the impact of this initiative before looking at the allocation of real-time congestion uplift costs. The ISO and stakeholders can use analysis once these market changes are in-place for a sufficient time to decide whether to proceed with an initiative addressing real-time congestion uplift cost allocation.

2. Mitigating Transient Price Spikes, Real-Time Imbalance Energy Offset (RTIEO)/ Real-Time Congestion Offset (RTCO) – The following four efforts address transient price spikes and uplift costs:

- Lowering the $5,000/MWh transmission constraint relaxation penalty price to $1,500/MWh has helped reduce real-time congestion uplift costs. The ISO intends to further refine this approach by potentially developing a tiered approach or voltage level-based relaxation parameters as part of its planned "Stepped Transmission Constraint" initiative.
- The "Full Network Model Expansion" initiative mentioned above and implemented in 2014 directly addresses one of the root causes of real-time congestion imbalance offset costs by modeling expected unscheduled loop flow in the day-ahead market.
- The FERC Order 764 market changes implemented in 2014 created a 15 minute real-time market, which addressed the price discrepancy between hour-ahead scheduling process and five-minute prices that resulted in real-time imbalance energy offset costs. The ISO continues to investigate the cause of relatively high

real-time imbalance energy offset costs that persist despite the FERC Order 764 market changes.

- The market changes that will result from the in-progress “Flexible Ramping Product” initiative will lessen real-time price spikes due to a shortage in ramping capability

3. Standard Capacity Product Enhancements - This initiative would develop a monthly rather than annual charge for the Standard Capacity Product that reflects the market value of resource availability. The intent is to create more accurate price signals to participants. The ISO has incorporated the “Standard Capacity Product Enhancements” effort into the “Reliability Services” initiative. This initiative is expected to go to the Board of Governors in Q1 2015. It proposes, among other things, to revise the Standard Capacity Product to account for flexible requirements and change the associated incentive price for all capacity types.

4. Modify Resource Adequacy Replacement Rules - This initiative would seek to change the rules requiring local or flexible capacity shown as generic system capacity to be replaced at the higher quality level during an outage rather than merely with an alternative generic system capacity resource. The ISO has incorporated the “Modify Resource Adequacy Replacement Rules” effort into the “Reliability Services” initiative. This initiative is expected to go to the Board of Governors in Q1 2015. The replacement rules initiative addresses concerns regarding the replacement rule and as part of a holistic revision is addressing the issues with the current substitution rules that require certain system resources to be substituted by local resources in the event of a forced outage.

5. Extended Pricing Mechanisms - Although highly ranked, the ISO did not pursue a stakeholder initiative to look at extended pricing mechanisms, such as “convex hull” pricing, in 2014. The ISO believed it was better to focus on the major market changes being developed through other initiatives, including the “Energy Imbalance Market,” “FERC Order 764 Market Design,” “Full Network Model Expansion,” “Contingency Modeling Enhancements,” and “Flexible Ramping Product.” The ISO understands that the Midwest ISO’s proposal for an extended pricing mechanism required an overwhelming amount of resources and time and we believes that ISO and stakeholders resources were better applied to the other significant market changes.

2 Day-Ahead Market

The ISO's day-ahead market consists of the integrated forward market (IFM) and the residual unit commitment" (RUC) process. The ISO's new market design that included this day-ahead market resulted from the Market Redesign and Technology Upgrade" (MRTU) initiative implemented in April 2009. The structure and rules for the day-ahead market are presented in the business practice manuals for market operations and market instruments.[4]

2.1 Bid Cost Recovery for Units Running Over Multiple Operating Days (F)

This initiative is one of six market design enhancements that the FERC originally in its September 21, 2006 MRTU order directed the ISO to implement within three years after the start of MRTU in April 2009. Currently, bid cost recovery payments, i.e. "make-whole" payments, are determined for each operating day. Within each operating day, the ISO bid cost recovery calculations compare a unit's revenue to its bid-in costs to calculate its net revenue. If this net revenue value results in a shortfall, the unit receives a bid cost recovery payment for that operating day. This may not adequately consider instances in which a unit's run time crosses over from one operating day into the next. Because the bid cost recovery calculation does not calculate a potential revenue shortfall based on the entire run time of the unit, but rather evaluates each operating day individually, bid cost recovery payments are likely greater than if the ISO evaluated revenue shortfalls over the entire run time. This initiative would evaluate the appropriateness, and potentially the design, of bid cost recovery calculations reflect run times that cross operating days.

Status: FERC has granted the ISO's request for an extension of time to April 30, 2017.[5]

Cross-Reference: May also be considered in concert with "Multi-Day Unit Commitment in the IFM" and/or "Hourly Bid Cost Recovery Reform."

2.2 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 its September 21, 2006 MRTU order.[6] 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.[7] 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

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

[5] California Independent System Operator Corp., *Order on Motion for Waiver or, in the Alternative, Extension of Time*, Docket Nos. ER06-615-000, *et al.*, Sep 15, 2014.

[6] 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.

[7] Available at: http://www.caiso.com/2781/27817949719e0.pdf

within the bounds of alternative methodologies.[8] 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."[9] 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 is plans to release an analysis on alternative marginal loss surplus allocation methodologies by the end of 2014.

2.3 Multi-Day Unit Commitment in Integrated Forward Market (D)

Currently, the forward looking time horizon in the integrated forward market 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 whether resources are expected to run for a single or multiple days. 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 the integrated forward market.

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 is 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."

2.4 Multi-Stage Generator Bid Cost Recovery (D)

In 2014 he ISO implemented market design changes resulting from the completed "Renewable Integration Market and Product Review" and "Bid Cost Recovery Mitigation Measures" that now separately calculate bid cost recovery for the day-ahead and real-time markets. [10]

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 markets and under such conditions, the real-time cost as

[8] Available at: http://www.caiso.com/2828/2828977521d30.pdf
[9] *Ibid,* p. 4.
[10] http://www.caiso.com/Documents/Sep25_2013TariffAmendment-RenewableIntegrationMarket-ProductReviewPhase1_ER13-2452-000.pdf

part of the overall cost of the two markets could be refined further than the methodology used by the current 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.

2.5 Full Network Model Expansion – Phase 2 (D)

This initiative would pursue the second phase of the "Full Network Model Expansion" initiative completed in 2014. Although the market changes resulting from the first phase of the Full Network Model Expansion initiative models external balancing authority area generation, load, and interchange at its physical location throughout the Western Electric Coordinating Council area, it models imports and exports that the ISO market schedules as injections or withdrawals at the ISO's interties.

This initiative would complete the ISO's full network model expansion by making the following market changes:

- Modeling ISO market imports and exports using physical sources and sinks located throughout the Western Electric Coordinating Council area by creating "scheduling hubs."
- Considering e-tagging or settlement rules for imports and exports that may be appropriate when modeling imports and exports as sourcing and sinking at scheduling hubs.
- Remapping congestion revenue rights to scheduling hubs.
- Modeling of additional balancing authority areas in the Western Electric Coordinating Council.

3 Real-Time Market

The real-time market substantially changed in 2014 with the introduction of the 15-minute market resulting from the "FERC Order 764 Market Changes" initiative. The real-time market consists of the real-time unit commitment (RTUC) process, which produces financially binding 15-minute energy and ancillary service schedules and prices as well as start-up and shutdown instructions, and the real-time dispatch (RTD), which produces financially binding 5-minute energy dispatches. It also consists of the hour-ahead scheduling process (HASP), which schedules hourly-block imports and exports, and the short-term unit commitment (STUC) process, which issues start-up instructions looking out further in the future that the real-time unit commitment process.

For more details regarding the real-time market refer to the business practice manuals for market operations and market instruments.[11]

3.1 Contingency Modeling Enhancements (I, N)

The ISO has been using both exceptional dispatches and deploying some minimum online commitment constraints to ensure that the system can be returned to a secure state within 30 minutes of a transmission contingency. The 30 minute requirement is pursuant to the Western Electricity Coordinating Council-specific reliability standard WECC-TOP-007. This initiative introduces a constraint that will effectively reposition the system to ensure that it can return to a secure state within the 30 minute requirement. The constraint will be included in the market optimization, replacing the use of manual operations. The new preventive-corrective constraint also introduces a locational marginal capacity price to compensate generation and demand response resources that satisfy the constraint. Overall, the constraint is more efficient and can increase the ISO's ability to ensure system reliability.

3.2 Default Load Aggregation Point Level Proxy Demand Response (D)

Currently, there is no mechanism for a default load aggregation point level proxy demand response resource to be explicitly incorporated into the ISO market. Adding the ability to create a proxy demand response resource at the default load aggregation point level would allow potential utility default load aggregation point wide dynamic rate tariffs to be explicitly incorporated into the ISO markets. Additionally, a flexible capacity resource requirement has been developed to meet a system flexibility requirement and default load aggregation point level proxy demand response may be able to participate as a system flexible resource if the rules change.

3.3 Energy Imbalance Market Year 1 Enhancements (D)

The ISO will commence a stakeholder initiative in November 2014 to develop enhancements to the Energy Imbalance Market. The enhancements include items to address FERC compliance, commitments made during the original stakeholder process, and others identified during the implementation. The following lists the currently planned items to be discussed:

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

1. Greenhouse gas flag and cost based bid adder – FERC directed the ISO to develop a flag to allow participating resources to opt out of being considered for their energy output to be transferred into the ISO and to modify the greenhouse gas bid adder to be based upon the actual regulation compliance cost of the participating resource.

2. Dynamic market power mitigation on EIM transfers –The ISO previously committed to looking at an additional dynamic trigger in the local market power mitigation process for including Energy Imbalance Market transfer constraints into the Energy Imbalance Market area. For example, if Energy Imbalance Market transfer capability into the Energy Imbalance Market area exceeds the historical imbalance needs of the Energy Imbalance Market area, then in those hours the Energy Imbalance Market transfers constraint could be excluded from the market power mitigation procedures.

3. Flow entitlements for base schedules/day-ahead schedules – The ISO committed to evaluate adding this functionality if there is material impact on the constraints within a Energy Imbalance Market balancing authority area from other Energy Imbalance Market balancing authority areas or the ISO in the Energy Imbalance Market footprint. Currently the real-time congestion offset is based solely upon where the constraint is located. This enhancement would allocate a portion of an Energy Imbalance Market balancing authority area's real-time congestion offset to other Energy Imbalance Market balancing authority areas if the other Energy Imbalance Market balancing authority area's base schedule flows exceed agreed upon flow entitlements.

4. Potential Energy Imbalance Market-wide transmission rate – The ISO committed to review a potential transmission based upon six months of operational data. A discussion of potential approaches was included in the Energy Imbalance Market draft final proposal.

5. Bidding rules on external Energy Imbalance Market interties – Currently the Energy Imbalance Market design allows full discretion to the Energy Imbalance Market entity as to whether real-time economic bidding is allowed on intertie scheduling points with balancing areas outside the Energy Imbalance Market footprint. The ISO does allow real-time economic bidding on all intertie scheduling points of the ISO, including those intertie scheduling points that support Energy Imbalance Market transfers. This may result in inefficient market outcomes when an economic bid on the ISO intertie scheduling point wheels through an Energy Imbalance Market entity.

6. Timeline for submission of Energy Imbalance Market transfer Capability – Based on discussions with Nevada Energy on the release of transmission capacity, requiring the submission of the Energy Imbalance Market transfer limit prior to the start of the Energy Imbalance Market may be inconsistent with existing practices that allow transmission to be procured up to 20 minutes prior to the operating hour. This item will determine if changes to the timelines are required or the Energy Imbalance Market transfer capability can be calculated before or during the Energy Imbalance Market for a given operating hour.

3.4 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 and to more optimally commit units that can only start a limited number of times.

3.5 Extended Pricing Mechanisms (D)

The objective of this initiative would be to explore extended pricing mechanisms to either incorporate non-priced constraints into energy prices or to reduce uplifts. In the first option, the primary goal is to incorporate non-priced constraints into the energy prices. An example of a non-priced constraint is the minimum online commitment 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 “extended locational marginal pricing (LMP).” 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.

3.6 Flexible Ramping Product (I, N)

The “Flexible Ramping Product” initiative 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 up and down quantities, procured as separate products and potentially with procurement targets and clearing prices in both the day-ahead and real-time markets. The flexible ramping product will better compensate resources for energy in the upcoming real-time dispatch interval and for projected ramping needs in the future interval. Payment for future ramping will be through a flexible ramping product price that is separate from the energy price. The flexible ramping product initiative will also consider establishing flexible ramping product requirements regionally to ensure deliverability.

The ISO proposes to allocate the costs for this product based upon real-time "movement" of demand or supply that requires real-time dispatch of resources. The cost allocation methodology adheres to the ISO-developed cost allocation guiding principles completed in 2012.

Status: The Flexible Ramping Product" initiative is currently proceeding with the plan to bring it to the February 2015 Board of Governors meeting.

3.7 Hourly Bid Cost Recovery Reform (D)

The ISO implemented market changes in 2014 that separated bid cost recovery calculations and payments between the day-ahead and real-time markets. This initiative would break the bid cost recovery review horizon further in real time along the lines of the Market Surveillance Committee opinion on the bid cost recovery rule changes wherein it suggests that "separable decisions" should receive separate bid cost recovery. One possibility is that separate commitments of short-start units in the real-time market should be afforded separate bid cost recovery.

Cross-Reference: In the its FERC filing to separate bid cost recovery the ISO committed to consider more granular real-time bid cost recovery in coordination with the "Bid Cost Recovery for Units Running Over Multiple Operating Days" stakeholder initiative.

3.8 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.

3.9 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. FERC previously encouraged the ISO to pursue this design change as part of its order changing the transmission constraint penalty price from $5,000/MWh to $1,000/MWh.

3.10 Two-Tier Rather than Single Tier Real-Time Bid Cost Recovery Allocation (F)

This initiative is one of six market design enhancements that the FERC in its September 21, 2006 MRTU order agreed to allow the ISO to implement within three years after the start of MRTU in April 2009. The existing real time bid cost recovery cost allocation consists of a single tier charge that is allocated to measured demand. Stakeholders raised concerns regarding the single tier approach and have requested that the ISO implement a two tier charge similar to day-ahead bid cost recovery where the first tier would allocate costs based on cost causation principles.

FERC's MRTU order directed the ISO to work with stakeholders to develop a proposal for two-tiered allocation of real-time bid cost recovery costs that could be included within three years after the new market launch. The ISO subsequently requested FERC to allow more time for it to develop this market enhancement.

The ISO published an issue paper 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 request for an extension of time to April 30, 2017 to implement this functionality.[12]

3.11 Generator Contingency Modeling (N)

This initiative would modify the ISO's current spinning reserve and non-spinning reserve products to procure them more granularly than the existing ancillary service zones. This would provide greater assurance of deliverability of these contingency reserves and ensure that the ISO can recover from a generation contingency within the 10-minute requirement. Deliverability of contingency reserves today may be limited by transmission constraints that are not accounted for in today's zonal ancillary service procurement.

3.12 Natural Gas Pipeline Penalty Recovery (I, N)

In the 2012 the ISO conducted the "Commitment Cost Refinement" stakeholder initiative that addressed issues associated with generator bidding and commitment costs. As part of the proposal, in 2012 the Board of Governors approved a provision that would allow generators to seek recovery, under in limited circumstances, of natural gas pipeline penalties under the ISO bid cost recovery mechanism. While in 2013 the ISO implemented most of the approved commitment cost refinements, the ISO has not yet implemented the portion of the proposal that allows for the recovery of certain natural gas pipeline penalties. Changes in ISO markets and in electric/natural gas coordination since the proposal was approved warrant reconsideration of the

[12] California Independent System Operator Corp., *Order on Motion for Waiver or, in the Alternative, Extension of Time*, Docket Nos. ER06-615-000, *et al.*, Sep 15, 2014.

policy. This “Natural Gas Pipeline Penalty Recovery” initiative will explore whether there is a need for the penalty cost recovery provision, or whether it should be modified, extended or withdrawn due to changed circumstances.

Status: The “Natural Gas Pipeline Penalty Recovery” initiative is currently underway. Stakeholder comments on the issue paper are due on October 8, 2014.

4 Residual Unit Commitment

The purpose of the residual unit commitment (RUC) process is to assess any difference between the integrated forward market scheduled load and the ISO's demand forecast, and to ensure that sufficient capacity is committed or otherwise available for dispatch in real time to meet the demand forecast. For more details regarding the residual unit commitment process refer to the business practice manual for market operations.[13]

4.1 Consideration of Non-Resource Adequacy Import Energy in Residual Unit Commitment Process (D)

Early in the MRTU stakeholder process it was suggested the residual unit commitment process could consider non-resource adequacy import energy bids that did not clear the integrated forward market. It could potentially do this by treating these bids the same as bids of non-resource adequacy internal generators. This initiative would consider whether this is needed or appropriate. This potential market change was also raised in the convergence bidding stakeholder process as a means to provide more import capacity in the residual unit commitment process to replace physical intertie bids that are displaced by virtual bids in the integrated forward market.

4.2 Multi-Hour Block Constraints in Residual Unit Commitment Process (I, F)

This initiative is one of six market design enhancements that the FERC in its September 21, 2006 MRTU order agreed to allow the ISO to implement within three years after the start of MRTU in April 2009. SCE raised a concern that resources may be committed for a time period that is inconsistent with their offer, because the residual unit commitment process does not observe any multi-hour block constraints"

> "SCE requests that the ISO revise its software to honor multi-hour block constraints in for MAP Release 2." (See SCE Comments on Market Initiatives, July 28, 2006, at: http://www.caiso.com/1845/18459b7a4f300.pdf).

FERC's Sep 2006 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 residual unit commitment 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 residual unit commitment 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 the future.

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

Status: FERC has granted the ISO an extension of time to April 30, 2017 to implement this functionality.[14]

[14] California Independent System Operator Corp., Order on Motion for Waiver or, in the Alternative, Extension of Time, Docket Nos. ER06-615-000, et al., Sep 15, 2014.

5 Ancillary Services

The ISO procures four types of ancillary services products in the day-ahead and real-time markets: regulation up, regulation down, spinning reserve, and non-spinning reserve. Section 4 of market operations business practice manual describes these ancillary services.[15]

5.1 Ancillary Services Substitution (F)

This initiative is one of six market design enhancements that the FERC in its September 21, 2006 MRTU order agreed to allow the ISO to implement within three years after the start of MRTU in April 2009. FERC's September 9 MRTU order 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 directed 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.

Status: FERC has granted the ISO and extension of time to April 30, 2017 to implement this functionality.[16]

5.2 Blackstart and System Restoration (D)

The ISO initiated a blackstart and system restoration stakeholder process in 2012 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 amended the ISO tariff to implement the new standards through a new pro-forma blackstart agreement that made all generators that are included in the power restoration plan subject to the same pro-forma blackstart agreement. The second phase would address competitive procurement of blackstart capability, including how the ISO would compensate resources for blackstart services and allocate the costs.

5.3 Fractional Megawatt 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 Response Requirements (F)

FERC approved NERC standard BAL-003-1 in January 2014, which mandates new frequency response standards. This initiative would address any changes necessary to be in compliance with the new standards as well as potentially address additional enhancements. The increase in renewable resources may result in operational concerns due to lower system inertia. In order to

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

[16] California Independent System Operator Corp., Order on Motion for Waiver or, in the Alternative, Extension of Time, Docket Nos. ER06-615-000, et al., Sep 15, 2014.

address this emerging operational need, the ISO may also potentially consider additional products or services necessary to maintain system inertia within this initiative.

5.5 Pay for Performance Regulation Year One Design Changes (I)

This item involves the commitment of the ISO in their stakeholder process to review the ISO's market design to implement FERC Order 755 after one year. The ISO implemented FERC Order 755 through its "Pay for Performance" initiative that it implemented in spring 2013. The ISO market now compensates resources for mileage in addition to capacity, as well as for accurate response to the regulation control signal. Resources must meet a minimum performance threshold in order to continue to provide regulation. This "Pay for Performance Regulation Year One Design Changes" initiative is examining modifying the methodology for calculating the mileage accuracy and revising the minimum performance standard.

5.6 Regulation Service Real-Time Energy Make Whole Settlement (D)

This initiative would examine whether rule changes to rule changes are appropriate for the settlement of real-time imbalance energy when resources are providing regulation.

The regulation up and regulation down products allow the ISO to dispatch a resource up or down, respectively, in real-time within a defined capacity range using automatic generator control. The imbalance energy when this dispatch is different than a resource's scheduled operating level is settled as real-time instructed imbalance energy at the real-time price.

NCPA noted the price of this imbalance energy can result in a significant net loss to a resource despite the resource performing as dispatched by the ISO. For example, the ISO market can schedule a resource for downward regulation and then dispatch the unit down in real-time. If the energy price is high, this can result in the resource "buying-back" its energy schedule at a loss.

5.7 Voltage Support Procurement (F)

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

6 Congestion Revenue Rights

This section describes potential enhancements to the ISO's rules and systems related to congestion revenue rights, including both short-term (*i.e.*, one-year seasonal and monthly) congestion revenue rights, as well as long term congestion revenue rights. Congestion revenue rights are both allocated to load serving entities and auctioned to all market participants. Further details are available in the business practice manual for congestion revenue rights.[17]

6.1 Congestion Revenue Rights Enhancements to address Revenue Inadequacy (D)

During 2014, the ISO has experienced significant revenue inadequacy of congestion revenue rights. Revenue inadequacy occurs when the ISO pays more to congestion revenue rights holders in the settlement process than the integrated forward market collects for congestion. The ISO used existing tariff authority to model additional contingencies in both the annual and monthly congestion revenue rights release process starting in September 2014. In addition, the ISO expanded the number of paths that are adjusted in the annual process using the breakeven methodology applied to internal constraints and intertie scheduling points. While these enhancements will address excess release of congestion revenue rights, the ISO believes additional changes may be warranted to address revenue inadequacy. The changes contemplated by the ISO include the following:

1. Revisit the congestion revenue right full funding provision. Currently revenue inadequacy is allocated to measured demand and not congestion revenue right holders. This design element would consider appropriate allocation of the revenue shortfall to congestion revenue right holders.

2. Consider restrictions on congestion revenue rights that clear at no or minimal cost in the auction. Currently there are no bidding restrictions or clearing restrictions in the auction. This can result in auction awards that do not increase market liquidity, but nevertheless may lead to revenue inadequacy.

3. Consider modifications to the congestion revenue right claw back rule. In addition to concerns already highlighted by stakeholder and included in this stakeholder initiative catalog, this would examine whether additional market outcomes should be subject to the ISO rescinding congestion revenue right payments to congestion revenue right holders.

4. Consider allocating the real-time congestion offset to congestion revenue rights. Currently the ISO allocates the real-time congestion offset to measured demand. Other ISOs allocate this cost through their congestion revenue right balancing account. This would require the risk of the real-time congestion offset allocation to be priced in the congestion revenue right auction.

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

The ISO has previously held a congestion revenue right enhancement initiative every two years, but has not done so since 2011. A congestion revenue right enhancement initiative is not narrowly focused on a single item, but rather seeks to address a number of issues that are prioritized by stakeholders. The ISO would include this item as well as other congestion revenue right design elements if an initiative was started for 2015. Any congestion revenue right enhancement initiative must be completed and filed with FERC no later than July, in order for the new rules to become effective prior to the start of the 2015 annual congestion revenue right process.

6.2 Economic Methodology to Determine if Transmission Outage Needs to be Scheduled 30 Days Prior to 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.

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.

6.3 Flexible Term Lengths of Long Term Congestion Revenue Rights (D)

FERC's July 6, 2007 Order on congestion revenue rights encouraged the ISO to consider future flexibility to allow: (1) long term congestion revenue rights in excess of 10 years, or (2) annual congestion revenue rights with guaranteed renewal rights up to year 10, or (3) long term congestion revenue rights 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 congestion revenue rights. This initiative could also modify the annual congestion revenue right process to allow market participants in subsequent auctions to submit bids/offers for any remaining months in the current year, as well as any block of months in the current year.

6.4 Insufficient Congestion Revenue Right Hedging (D)

This initiative was suggested by CDWR:

> "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."

6.5 Long Term Congestion Revenue Right Auction (D)

The ISO's January 29, 2007 compliance filing on long term congestion revenue rights noted that several parties wanted the ISO to implement an auction process for long term congestion revenue rights, which the ISO agreed to consider for a future release. FERC's July 6, 2007 order on congestion revenue rights encouraged the ISO to initiate a stakeholder process and file tariff language to implement an auction for residual long term congestion revenue rights in a future release of the new market. If the ISO and the stakeholders decide to move forward with a long term congestion revenue right auction, then the ability to sell congestion revenue rights 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 congestion revenue right enhancement to enable a long term congestion revenue right release process to recognize future changes in transmission encumbrances over the horizon of the nominated long term congestion revenue rights (mainly the expiration of existing transmission contracts and converted rights and previously-released long term congestion revenue rights). 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 congestion revenue rights to the market as possible while minimizing the risk of congestion revenue right revenue inadequacy. In the context of an auction for long term congestion revenue rights, the multi-period optimization would result in auction prices that more accurately reflect the expected values of the long term congestion revenue rights being awarded. The ISO therefore believes that the multi-period optimization algorithm would likely be an essential component of a long term congestion revenue right auction.

One proposal (EMTRI 2013) for the long term congestion revenue right auction suggests (1) running a sequential rather than concurrent quarterly auction, (2) have multiple rounds for a given auction, and (3) implement a rolling auction where future periods such as future months, quarters, half-a-year strips, or years can be traded multiple times.

6.6 Multi-Period Optimization Algorithm for Long-Term Congestion Revenue Rights (D)

This initiative would examine a multi-period optimization algorithm for long term congestion revenue rights. When the ISO performed the initial release of long term congestion revenue rights for the period 2008-2017, the simultaneous feasibility test optimization treated 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. A multi-period algorithm may result in a more optimal allocation of long term congestion revenue rights because it would reflect different assumptions for each year regarding the availability of grid capacity for congestion revenue rights, in particular the known expiration of previously released long term congestion revenue rights, existing transmission contracts, and converted rights.

6.7 Outage Notification Requirements (D)

This initiative would modify the rules for releasing outage information prior to congestion revenue rights auctions. DC Energy suggests outage reporting should be done more in advance to increase the information known to congestion revenue right auction market participants, while recognizing that some outages (emergency, etc.) cannot be known in advance. DC Energy maintains other ISOs have more specific rules on outage reporting requirements, including notice of such known outages up to one year in advance.

6.8 Review Congestion Revenue Right Clawback Rule (D)

Powerex recommends a new initiative to review the design and effectiveness of the congestion revenue right clawback rule. Powerex maintains the ISO’s congestion revenue right clawback rule is deficient in its design leading to: 1) the ability of participants to submit small volumes of convergence bids, which inappropriately inflate the value of congestion revenue right holdings while crowding out physical supply and distorting efficient market outcomes, and 2) undesirable discouragement of physical decremental bids in circumstances where no inappropriate congestion revenue right benefit could be gained.

7 Convergence Bidding

Convergence (or virtual) bidding is a mechanism whereby market participants can make financial sales (or purchases) of non-physical 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 improve the efficiency of the markets because they tend to make day-ahead and real-time market prices converge.

7.1 Allowing Convergence Bidding at Congestion Revenue Right Sub-Load Aggregation Points (D)

Currently convergence bidding does not allow virtual bids at congestion revenue right sub-load aggregation points (LAPs). WPTF submitted comments suggesting that the ISO should consider adding congestion revenue right sub-LAPs to the available locations for convergence bidding.

7.2 Convergence Bidding Clawback (D)

This initiative would examine changes to the removed from the congestion revenue right revenue adjustment rule outlined in tariff section 11.2.4.6. This section excludes congestion revenue right revenue adjustments (clawback rule) on the LAPs and generation trading hubs:

> "For each congestion revenue right 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 congestion revenue right 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 congestion revenue right payments from convergence bids. Due to their smaller sizes, the ISO Department of Market Monitoring recommended that the exemption of the VEA and SDG&E LAP be removed from the congestion revenue right revenue adjustment rule outlined in tariff section 11.2.4.6.

7.3 Implement Point-to-Point Convergence Bids (D)

Currently CAISO market participants can bid either virtual supply or virtual demand. This initiative, proposed by DC Energy, would examine market rules to allow market participants to bid point-to-point – a source and a sink combined with specified price. Other markets, such as PJM and ERCOT, have point-to-point convergence bids.

Point-to-point virtual bid would clear as long as the specified price is greater than the difference between sink and source in the day-ahead market. A point-to-point virtual bid will pay the difference of locational marginal price at the sink minus locational marginal price at the source in the day-ahead market and will be paid that difference in the real-time market. These price differences may be positive or negative, determining whether the market participant is paid or has to pay in either market.

7.4 Review of Convergence Bidding Uplift Allocation (D)

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. SCE notes that in its May 9, 2013 order on lowering the transmission relaxation parameter, the FERC wrote "The Commission encourages CAISO to pursue its evaluation [of proper uplift allocation] vigorously and to propose solutions to the observed difficulties promptly when they become evident."[18] Under current tariff provisions, all uplifts associated with convergence bidding are allocated to demand. This initiative would be to conduct a comprehensive evaluation of the costs and benefits associated with convergence bidding and to implement a method or methods for allocating the costs of convergence bidding to the entities that benefit from convergence bidding.

[18] Paragraph 28, ORDER ON TARIFF REVISIONS, May 9, 2013, ER13-1060-000, http://www.ferc.gov/EventCalendar/Files/20130509152959-ER13-1060-000.pdf.

8 Resource Adequacy and Long-Term Supply Sufficiency

The ISO works closely with local regulatory authorities to develop and implement resource adequacy policies and rules that ensure sufficient capacity exists in the balancing area in the right places and with the right capabilities. While the ISO does not take the lead role in establishing system resource adequacy requirements, the ISO does have specific and essential responsibilities in most all resource adequacy related functions, including establishing local and flexible resource adequacy capacity needs.

Ensuring the long-term supply sufficiency for the balancing area is undertaken by the CPUC through its Long Term Procurement Plan (LTPP) rulemaking, and through the integrated resource planning functions of non-CPUC jurisdictional entities and municipalities.

The ISO collaborates with all local regulatory authorities to ensure long-term supply sufficiency and short-term resource adequacy needs are satisfied within the balancing area. This collaboration includes assessing and communicating local and flexible capacity needs, establishing backstop procurement rules and authority to satisfy any remaining unfulfilled capacity needs, and setting and enforcing tariff provisions that specify the “must-offer obligations” applicable to resources that supply resource adequacy capacity to the balancing area. Most all of this work is vetted through stakeholder engagements and in coordination with local regulatory authorities.

Given the rapidly evolving supply fleet and the growing numbers of intermittent renewable resources, the ISO’s “supply adequacy” role is evolving. In particular, the rapid increase in intermittent renewable resources has required the ISO to quantitatively assess its needs for flexible capacity and, in so doing, pursue initiatives to ensure that sufficient capacity with the right capabilities will be available when and where needed. Against this context, the initiatives described in this section address enhancements to ensuring resource adequacy and long-term supply sufficiency.

8.1 Reliability Services (I, N)

The “Reliability Services” initiative is a multi-phase, multi-year effort to address the ISO’s rules and processes surrounding resource adequacy resources. Although the current program has generally provided for reliable operation of the grid, significant and growing amounts of new renewable and preferred resources are being added to the grid, which requires a reassessment of the program. This initiative will propose necessary changes to ensure sufficient resources with the right capabilities are available and offered into the ISO markets to meet local, flexible, and system capacity requirements.

In the first phase the initiative will focus on resource adequacy rules and processes that must be updated quickly for reliability or regulatory reasons. These mostly relate to enhancements to further integrate preferred resources into the grid, rules for the newly determined flexible resource adequacy requirement, and an update to the availability incentive mechanism.

In the second phase the initiative will propose a durable construct for flexible resource adequacy resources. It will also consider other needed rule changes to accommodate a durable flexible resource adequacy structure, as well as assess how well resources are performing under the new availability incentive mechanism, and propose flexible RA replacement rules.

Status: This initiative is currently underway. The ISO plans to present a proposal to the Board of Governors in the first quarter of 2015.

8.2 Capacity Procurement Mechanism (I, N)

This initiative will design a capacity procurement mechanism to replace the current backstop procurement mechanism that expires February 16, 2016. The proposal will include a durable mechanism and market-based price for the ISO to procure capacity not designated for resource adequacy in order to meet reliability needs. The ISO plans to present a proposal to its Board of Governors in the first quarter of 2015.

Status: This initiative is currently underway. The ISO plans to present a proposal to the Board of Governors in the first quarter of 2015.

8.3 Joint Reliability Plan (I)

Although not an ISO stakeholder initiative, the ISO is working closely with the CPUC and California Energy Commission (CEC) on a "Joint Reliability Plan." The Joint Reliability Plan resulted from extensive cooperation between CPUC and ISO staff following a long-term resource adequacy summit jointly hosted by the CPUC and the ISO back in February 2013.

In discussions leading to the development of the Joint Reliability Plan, CPUC and ISO staff agreed that establishing three-year forward capacity procurement obligations may provide a number of benefits if properly designed. The CPUC has opened a rulemaking (R. 14-02-001) to consider the following issues:

- Two- and/or three-year forward-looking resource adequacy procurement requirements;
- Implementing a long term joint reliability planning assessment with the ISO and CEC; and
- Determining rules and CPUC policy positions with respect to the ISO's development of a market-based backstop procurement mechanism to succeed its existing Capacity Procurement Mechanism that expires in 2016.

Status: The ISO is actively participating in the CPUC's proceeding.

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 Make Whole Process for Wheel-Through Transactions (D)

Under the current ISO market rules, wheel-through transactions receive make-whole payments on the export side as a result of price corrections, but 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.

9.2 Mitigation of Transmission Cost Increases (D)

This initiative would address the measures that could mitigate increases in transmission costs without adversely affecting necessary grid enhancements. This could potentially include developing provisions to require transmission developers to disclose in the competitive solicitation process any incentives that the developer intends to seek from the FERC (if a petition for such incentives has not previously been filed) and to provide the ISO with documentation comparing the estimated cost of the transmission project with and without the incentives.

10 Infrastructure and Planning

This section includes policy initiatives related to infrastructure and transmission planning.

10.1 Interconnection Process Enhancements (D)

The ISO is committed to continually reviewing potential enhancements to its generation interconnection process to reflect changes in the industry and to better accommodate the needs of interconnection customers. Consistent with this commitment, the ISO has conducted a series of stakeholder processes over the past several years to improve the process. These include Generation Interconnection Process Reform ("GIPR") held in 2008-09, Generation Interconnection Procedures Phase 1 ("GIP 1") held in 2010, Generation Interconnection Procedures Phase 2 ("GIP 2") held in 2011 and early 2012, Generation Interconnection Procedures Phase 3 ("GIP 3") held in 2012, and Interconnection Process Enhancements ("IPE") held in 2013 and 2014. The ISO is offering to hold another IPE initiative in 2015 to consider further improvements and will begin by gathering potential topics for consideration in late 2014.

10.2 Active Power Control Interconnection Requirements (D)

This initiative for variable energy resources would consider various interconnection requirements for both small and large asynchronous generators (principally solar and wind). In 2010, FERC rejected without prejudice interconnection requirements the ISO proposed for large asynchronous generating facilities. The ISO proposed to require these facilities to have reactive power, automatic voltage control and active power management capabilities. This initiative would specifically focus on active power control interconnection requirements for asynchronous generating facilities.

10.3 Reactive Power Requirements (D)

The initiative for variable energy resources would consider proposing a tariff amendment requiring all asynchronous generating facility to have net reactive power sourcing and absorption capability sufficient to achieve or exceed a net reactive power range of approximately 0.95 leading and 0.95 lagging while maintaining a scheduled voltage at the point of interconnection of the facility to the grid.

10.4 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.

Given other high priority infrastructure policy issues, as well as time and resource constraints of the ISO and stakeholders, the ISO will address this issue only if time permits.

10.5 Transmission Planning Process Competitive Solicitation Improvements (D)

The ISO began this initiative with a stakeholder meeting on March 6, 2014 to discuss “lessons learned” from the 2012-2013 transmission planning process competitive solicitations. The ISO’s intention was to use the March 6 stakeholder meeting to mark the start of an effort with stakeholders to identify potential enhancements that could improve the efficiency and effectiveness of the competitive solicitation process. The ISO differentiated between (1) potential enhancements that it could apply to Phase 3 of the 2013-2014 transmission planning process and (2) issues that have potential policy implications and require more comprehensive stakeholder consultation. The ISO also discussed its intention to work with stakeholders to develop a pro forma approved project sponsor agreement (APSA) for the 2013-2014 TPP competitive solicitation. The ISO invited stakeholders to submit written comments following the March 6 meeting.

The ISO has taken several actions since the March 6 “lessons learned” stakeholder meeting.

First, after reviewing and evaluating the written stakeholder comments, the ISO made some process improvements prior to the 2013-2014 competitive solicitation. These changes are discussed in more detail in section 5.1 of this paper.

Second, the ISO posted a draft pro forma APSA and sought stakeholder comment on March 21, 2014. The ISO received eight sets of comments and held a web conference to discuss the proposal on May 5, 2014. The ISO posted a revised pro forma APSA on May 7, 2014 and held an additional teleconference to discuss the draft on May 19, 2014. On September 10, the ISO submitted the proposed pro forma APSA to FERC for approval.

With these two activities complete, this stakeholder initiative will now focus on other issues raised in the March 13, 2014 stakeholder comments that have potential policy implications and require further consultation with stakeholders. As a next step, the ISO wants to provide an opportunity for all stakeholders to provide their input regarding these other issues raised by stakeholders in the March 13 stakeholder comments. The ISO will evaluate and consider this additional feedback before determining subsequent steps in this initiative.

10.6 Energy Storage Interconnection (D)

The ISO launched the energy storage interconnection initiative in late March 2014 in anticipation of receiving interconnection requests for energy storage in the Cluster 7 application window (i.e., the window that would close April 30, 2014). The initial purpose of the initiative was to provide a forum for issue identification and solution development related to energy storage interconnection requests to the ISO controlled grid.

The ISO's first step in this initiative was to reach out to stakeholders, present its proposed approach for accommodating storage interconnection requests under existing rules, and solicit stakeholder feedback. To accomplish this the ISO held a stakeholder web conference on April 7 to discuss existing processes available for the interconnection of energy storage facilities to the ISO controlled grid and how it intended to use these existing processes to accommodate the storage interconnection request applications anticipated in Cluster 7. Following this initial web conference, stakeholders were invited to submit written comments by April 14 on issues of immediate concern – i.e., those related to interconnection request applications planned to be in Cluster 7. Stakeholders were also invited to raise issues of a policy nature and the ISO discussed these in an issue paper and straw proposal posted on June 24.

In response to issues of more immediate concern raised by stakeholders, the ISO posted supplemental information on the ISO website on April 22. This document clarified the technical data necessary to ensure that the ISO studies Cluster 7 energy storage projects appropriately. The document also clarified that the ISO will use information from the discharge cycle in the deliverability assessment for Cluster 7 – i.e., the ISO will use the four-hour discharge capacity, which is at most the total storage capacity in MWh divided by four.

In the June 24 issue paper and straw proposal the ISO further clarified its approach for applying the GIDAP to Cluster 7 storage projects based on further development by the ISO and a consideration of feedback received from stakeholders. The ISO held a stakeholder web conference on July 1 and invited stakeholder comments by July 15.

Since issuing the June 24 paper, the ISO has continued to refine its approach and address other storage-related issues raised by stakeholders. At the time it issued the June 24 paper the ISO's focus was on continuing to address issues pertaining to how to accommodate Cluster 7 energy storage interconnection requests under existing GIDAP rules while simultaneously staying open to considering and proposing modifications to the GIDAP to be applied to Cluster 8 and beyond. At that point in time the ISO was expecting that it may present proposals for modifying GIDAP rules to the ISO Board of Governors for approval in November of this year.

However, after reviewing stakeholder comments received on July 15 and upon further examination by the ISO, no changes to the GIDAP had been identified as necessary to accommodate storage interconnection to the ISO grid.

The ISO then held an in-person stakeholder meeting on August 13 to further clarify for stakeholders its application of existing GIDAP rules to Cluster 7 storage projects as well as subsequent queue clusters, review existing processes for project modification, and begin to discuss resource adequacy-related interconnection issues. The ISO also used this meeting to further explore with stakeholders whether changes to the GIDAP were needed. Written stakeholder comments were requested by August 20.

Based on a review of stakeholder comments the ISO has concluded that no changes to the GIDAP have been identified as necessary to accommodate storage interconnection to the ISO grid. As a consequence, the stakeholder process schedule has been modified to eliminate the step of going to the November ISO Board meeting. A second paper will be produced to further clarification its application of existing GIDAP rules to storage projects and address other issues raised in this initiative.

10.7 Maximum Import Capability

As set out in the ISO tariff, the ISO is responsible to determine the maximum import capability for each import path into the ISO balancing authority area, so that imports can be included in the state's resource adequacy program. The methodology to establish these maximum import capabilities is set out in the ISO's Business Practice Manual for Reliability Requirements, and was developed through extensive stakeholder consultation when the state's resource adequacy program was developed. Key attributes of the methodology include the fair and reasonable consideration of imports, and the need for simultaneity among the resources included in resource adequacy capacity assessments.

The ISO's annual transmission planning process includes provisions for meeting federal and state policies, which presently focus on achieving the state's 33% renewables portfolio standard. To this end, since 2011 the ISO has targeted enabling 1400 MW of renewable generation imports from Imperial County to be deliverable. This stemmed from efforts the ISO made in 2011 to support the viability of renewable generation being considered in the CPUC's 2011 RPS procurement proceeding. While much less than the 1400 MW of renewable generation actually materialized, there remains strong stakeholder interest in ensuring that future renewable generation developments connecting to the Imperial Irrigation District may be placed on an even footing with ISO-connected generation in helping to meet resource adequacy requirements as imports into the ISO grid.

The ISO continues to test the level of future potential deliverability in each year's annual transmission plan review, by studying the renewable generation portfolios provided by the CPUC. However, in the 2013-2014 transmission planning process, the ISO noted the deliverability of future renewable generation from the Imperial Valley area may be significantly reduced from previous estimates primarily due to changes in flow patterns resulting from the retirement of the San Onofre Nuclear Generating Station. Despite the impacts being heavily offset by other reinforcements proposed in the transmission plan, the amount of deliverability available from the Imperial area (whether connected to the ISO grid or to IID) may not be sufficient to meet projects that are already proceeding and overall reductions in net qualifying capacity to those resources may be necessary even without further renewable generation development in the area. Additional deliverability analysis is being conducted in the 2014-2015 transmission planning process to further refine deliverability results identifying (for informational purposes only) the most effective solution to achieve previously targeted deliverability levels. This has raised numerous questions with the methodology used to assess maximum import capability, and in particular, the methodology used to establish these levels on other paths that limit increases in deliverability from IID.

Further, the ISO has acknowledged the concept proposed by a number of stakeholders to reallocate a portion of Arizona MIC to IID, recognizing that both rely on the same internal ISO system. (ISO studies have indicated that, at current MIC levels, for every 2 MW of MIC reduction from Arizona, MIC can be increased from IID by 1 MW.) Stakeholders have provided mixed feedback on this concept – some support, some opposition, and a large number of issues identified that would need to be considered.

10.7.1 Comprehensive Review of Methodology for determining Maximum Import Capability

The current methodology for determining import paths' maximum import capability is tied to the last two years' historical data, unless the importing area is receiving unique consideration through policy direction from the state – as is currently the case for IID. This historically-based methodology was selected at the time as it ensured that the established levels were reasonable and could actually be achieved simultaneously. Further, the methodology set aside the contentious issue of study assumptions; in particular as major sources of potential import into the ISO are from sources that cannot enter into binding long term contracts.

Stakeholders in the transmission planning process have suggested that a comprehensive review of the methodology should be undertaken, in part to address changes in state policy regarding preferred locations for renewable generation.

Based on the challenges of establishing the current methodology at the time the state resource adequacy program was developed, a comprehensive review is expected to be a significant undertaking with a major commitment of policy and technical staff.

Status: This item is being included in the stakeholder initiative catalogue to garner feedback and assess stakeholder interest in this initiative.

10.7.2 Reallocation of Maximum Import Capability between Electrically Adjacent Import Paths to achieve State Policy Objectives

As noted above, the assessed deliverability from the Imperial area may impact projects already moving forward, and may limit future renewable generation's ability to participate in the state's resource adequacy program due in part to the methodology in determining available maximum import capability on other paths that affect deliverability out of the Imperial area. Stakeholders have suggested that the ISO methodology be revised to reallocate a portion of maximum import capability from one path to another (if electrically feasible) to enable state policy objectives to be achieved while minimizing the need for further system reinforcement.

Status: This item is being included in the stakeholder initiative catalogue to garner feedback and assess stakeholder interest in this initiative. However, the ISO is expecting to delay any consideration of this initiative at least until the results of the 2014-2015 transmission planning analysis are available in mid-November 2014 and the necessity of moving forward can be considered. The ISO is retaining for future use the issues that stakeholders have identified as needing consideration if this initiative is advanced.

10.7.3 Allocation of Maximum Import Capability among Load Serving Entities

In addition to the above two issues, a third issue has been raised through separate stakeholder discussions regarding the allocation of maximum import capability among ISO load serving entities. The current methodology for allocating maximum import capability to ISO load serving entities is based on load share.

Stakeholders have suggested that this methodology is an economically inefficient process as the shares of all import paths are distributed through this mechanism, resulting in small shares for some load serving entities that are not viable to secure resources behind, and that other participants are not motivated to relinquish their shares on these paths so that material arrangements can be put in place with capacity outside of the ISO.

The ISO considers that this issue could be considered in isolation, without necessitating the comprehensive review referred to above.

Status: This item is being included in the stakeholder initiative catalogue to garner feedback and assess stakeholder interest in this initiative.

11 Other

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

11.1 Bidding Rules (N)

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 informed by 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.

This initiative will address these concerns in the context of, and along with, several topics that came up in the recently completed “Commitment Cost Enhancements” initiative:

- Reflection of intra-day natural gas costs (either through greater bidding flexibility or directly invoicing for certain gas costs) and the market rules and implementation changes needed to support it.

- Potentially breaking up the current three-day weekend gas “package” into separate Saturday/Sunday and Monday packages.

- Creating a process to periodically review the cost cap to ensure that it still enables headroom for market participants to accurately reflect their natural gas costs.

- Consideration of using only a single gas price index (and potential change to the existing day-ahead market close timeline).

11.2 Opportunity Cost Methodology (N)

This initiative will finish developing the opportunity cost methodology that will reflect use-limited resources’ limited operating hours. The opportunity cost methodology calculates a start-up and/or minimum load cost for a resource that will result in the ISO market not starting or operating the resource more than its allowable operating hours over a year. The start-up and minimum load provisions would be modified to allow the market participant to bid up to this cost in the ISO day-ahead and real-time markets.

11.3 Pricing Enhancements (I, F)

This initiative includes the scope of the administrative pricing rules initiative plus additional pricing enhancements for improving ISO market efficiency. Through this stakeholder process we will examine tariff provisions regarding market intervention during significant system emergencies and settlement of force majeure events. We also seek enhancements to address multiplicity of prices, compounded congestion due to multiple concurrently binding contingencies and schedule priorities for existing transmission rights.

Status: This initiative is in-progress and is planned to go to the December Board of Governors meeting.

11.4 Aggregated Pumps and Pump Storage (D)

The ISO had designed its proxy demand resource to allow direct participation for a single resource to both schedule demand and bid load curtailments as an integrated bid. Proxy demand response 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 proxy demand response product provided demand response resources with full comparable functionality to that of a generator in the ISO's markets, CDWR commented that proxy demand response did not fully meet the needs of participating loads and was designed for retail load.

In 2010 the ISO conducted a preliminary analysis of how the multi-stage generator modeling functionality might be adapted to accommodate the particular operating characteristics of aggregated pumps and pump storage facilities. The envisioned changes would enable multi-stage generators 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 multi-stage generators model for aggregated pumps or pump storage facilities.

11.5 Combined Demand Response Product (D)

This initiative would be part of the ISO's continuing efforts to incorporate non-generating resources into the ISO's markets and provide these resources more opportunities and options for participation. This initiative would examine combining the features of the ISO's current non-generating resource model and the proxy demand resource product for demand response. The combination would 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 combined demand resource product could allow direct measurement of response for resources capable of individual metering.

11.6 Exceptional Dispatch Decremental Settlement (N)

This initiative addresses two settlement rule issues for decremental exceptional dispatch energy and shut-down energy (energy from minimum load to shutdown). First, decremental energy settles at the lower of the locational marginal price, default energy bid, or market bid, and this initiative would look at other potential settlements. Second, 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.

11.7 Expanding Metering and Telemetry Options (I, N)

Responding to market participant requests for additional options for metering and telemetry configurations, this initiative has been investigating 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.

Status: Activities related to this initiative have been on hold because of ISO resource constraints.

11.8 Generator Unit Testing (N)

The ISO would 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.

11.9 Integrated Optimal Outage Coordination (D)

In an effort to improve and expedite outage management studies and decisions on system-wide level, the ISO is developing an analysis engine capable of solving the short-term integrated optimal outage coordination. The “Integrated Optimal Outage Coordination” application is intended to provide a comprehensive support for the operation engineers and outage coordination groups in their evaluation and approval process of both transmission and generation outages in an integrated system-wise and optimal manner.

Using the Integrated Optimal Outage Coordination application, the ISO will have the ability to consider physical characteristics of resources, system and network constraints in addition to the constraints associated with independent and dependent repairs. The Integrated Optimal Outage Coordination application will provide an optimal outage schedule while ensuring reliable system operation. In the first phase, the resulting outage schedule will be optimal in the sense that it can minimize bid-in costs while taking into account physical constraints of generating and transmission assets and maintaining power system reliability requirements.

For the second phase of this project, the ISO intends to include economic criteria for approving or rejecting planned outage repair requests. Full application of the Integrated Optimal Outage Coordination application in outage evaluation processes using economic criteria is planned during 2015, after completion of necessary stakeholder process with expected outage management business practice manual and tariff changes.

11.10 PacifiCorp related Tariff Changes (F)

In 2013 the ISO filed at FERC a proposal to make modifications to the Operating Agreement between the ISO and PacifiCorp that was filed as part of the 2007 Offer of Settlement in ER07-

1373, et al, to accommodate changes requested by PacifiCorp regarding use of their share of transmission rights associated with this agreement. The Commission accepted the ISO's proposal. The ISO's effort in making this change was to further our commitment to improve the efficiency of scheduling transmission between balancing authorities. Although this approach only directly affects PacifiCorp and its customers who have acquired the right to use a portion of the PacifiCorp share, the ISO indicated, in its filing that it would present this in our catalog to consider expanding the proposal to other similarly situated rights.

The approach that has been approved by FERC allows PacifiCorp or a purchaser of PacifiCorp's share of transmission rights to relinquish a portion of their reserved capacity and receive congestion credits in lieu of the perfect hedge associated with using a contract reference number and balanced source and sink schedule. The ISO could discuss with other stakeholders to offer this approach more broadly if such interest exists. This approach represents alternative treatment for transmission ownership rights made available as an option to parties utilizing such rights.

11.11 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.

11.12 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.

11.13 Load Granularity Refinements (I, N)

Through this initiative the ISO and stakeholders will evaluate alternatives for the level of granularity load should bid, schedule and financially settle in the ISO market. The ISO has until June 3, 2015 to provide FERC its proposal in accordance to FERC's rejection of the ISO January 2014 request for waiver of the requirement to disaggregate the existing default load aggregation points.

Status: The "Load Granularity Refinements" initiative is currently proceeding with the plan to bring it to the March 2015 Board of Governors meeting.

12 Completed Initiatives

This section provides a list of initiatives completed since the ISO published last year's Stakeholder Initiatives Catalog. 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. Initiatives presented here will be deleted from the next edition of this catalog.

12.1 Flexible Resource Adequacy Criteria and Must Offer Criteria

The ISO worked with the CPUC and other local regulatory authorities 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 "Flexible Resource Adequacy Criteria and Must Offer Criteria" initiative lead to tariff changes necessary to implement the proposed flexible capacity changes to the CPUC's and other local regulatory authorities' resource adequacy programs. The initiative established how the system flexible capacity needs are determined and allocated to local regulatory authorities so that they can establish procurement requirements. The initiative also established must offer requirements for resources providing flexible RA capacity and provisions for the ISO to conduct backstop procurement of flexible capacity.

12.2 Full Network Model Expansion

Through this initiative, the ISO expanded its full network model to improve reliability and market solution accuracy. This expansion consisted of:

1. Expanding the model of the physical electric network used by the ISO market to include the other balancing areas in the Western Electricity Coordinating Council area.

2. Modeling in the ISO market the unscheduled electrical flows that will occur within the ISO balancing area based on expanded network topology caused by the load, generation, and interchanges forecast for other balancing areas in the western interconnection.

3. Modeling of unscheduled flow to produce feasible ISO market schedules and incorporating the unscheduled flow into ISO market prices. This will include incorporating physical flow limits over the certain ISO interties into the ISO markets, where currently the ISO markets only enforce limits on scheduled flow.

This expansion was consistent with FERC and NERC recommendations following the September 8, 2011 southwest power outage. 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 were to enhance: 1) loop flow modeling; 2) security analysis; 3) representation of high voltage direct current transmission; and 4) outage analysis and coordination.

The ISO deferred several components that were originally included in this initiative to a second phase. Section 2 describes the “Full Network Model – Phase 2” initiative.

12.3 Commitment Costs Enhancements

The ISO reviewed how start-up and minimum load costs are calculated and incorporated into the market under the registered and proxy cost options. This was a follow-up to the technical bulletin on the natural gas price calculation tariff waiver published on February 21, 2014. As part of this review, the ISO considered various enhancements to ensure accurate and timely consideration of commitment costs components. The goal of this effort was to identify solutions that can be implemented in the near-term. It resulted in modifying the proxy-cost option bid cap to 125 percent and retaining the registered cost option for only use-limited resources.

12.4 Contingency Reserve Cost Allocation

This initiative modified the allocation of costs to procure contingency reserves. This was to align the cost allocation with WECC’s new standard for calculating contingency reserve requirements for balancing authority areas that went into effect on October 1, 2014.

12.5 Competitive Transmission Improvements

The intent of this initiative in 2013 was to further promote competition in the transmission planning process and implement a mechanism to recover the cost of administrating Phase 3 of the process. Through this initiative the ISO worked with stakeholders to develop tariff revisions to clarify the process, implement improvements and respond to issues raised by stakeholders and submitted the tariff revisions on January 30, 2014. On March 31, 2014, the FERC accepted the ISO’s filing, effective April 1, 2014, subject to a subsequent compliance filing. The revised tariff language was first applied to the 2013-2014 transmission planning process competitive solicitation.

12.6 Generator Interconnection Procedures 3 (“GIP 3”)

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.

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 IPE initiative had a scope of fifteen generation interconnection related topics. Proposals to address eleven of the fifteen topics have been filed with and accepted by FERC, two more are in the process of being filed, and the final two addressed through the Business Practice Manual change management process.

12.7 Affected Systems

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 the initiative was to add further detail to the ISO's business practice manual for generator interconnections on the processes and principles for addressing "affected system" impacts in 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. In Q3 2014, the ISO incorporated into its business practice manual new affected systems language that was developed in the affected systems initiative. Potential further changes to the affected system provisions will be considered during the scoping of topics for the next Interconnection Process Enhancements stakeholder initiative.

12.8 Revisions to ISO Planning Standards

ISO planning standards was completed in 2014 with the revisions being approved by the ISO Board at the September Board of Governors meeting.

13 Catalog Deletions

The following initiatives will be deleted and will not be carried forward to the next edition of the catalog (pending stakeholder input). This is because they are either no longer relevant and/or needed, have been addressed in other ways, or have been subsumed under another initiative listed in the catalog.

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.

Status: This initiative was subsumed into the Contingency Modeling Enhancements initiative which creates a 30-minute reserve product.

13.2 Regulatory Must-Run Pump Load (D)

This initiative 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: Market participants previously requested time to analyze the implications of the policy. Initiative should be deleted because need for it is not clear.

13.3 Develop a Process for Enforcement/Un-enforcement of Constraints (D)

This initiative would create a process for reviewing and implementing significant changes in market constraints. Stakeholders would have to decide, as they have in other ISO/RTO markets, the level of materiality that would trigger an open review as well as the amount of notice that is reasonable prior to making a substantial change. Stakeholder comment: “Calpine notes, the un-enforcement of the SCE_IMP_PCT constraint created great alarm and surprise in the market. This constraint had created substantial congestion in the market and may have been the basis of forward market hedging for a significant share of market participants. Few argued with the technical rationale for removal of the constraint (once explained), but virtually all uninvolved market participants voiced concerns over the process and timing of the relaxation.” (Calpine 2013)

Status: Should be deleted because this is a potential process improvement and not a stakeholder initiative that would result in a market change.

13.4 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.

Status: The need for this has become obsolete with the FERC Order 764 market design that enables intermittent resources to submit economic bids enabling them to be curtailed based on economics.

13.5 Directional Bidding in Real-Time Market (D)

This initiative would 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). This had been said to be 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. Enhancements could 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. This mechanism may improve grid reliability and market efficiency by allowing more capacity to actively participate in the real-time market. (NCPA 2012)

Status: The current market already provides this functionality.

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

Language suggested by PGE: "Market volatility has increased significantly in the real-time market, which can drastically increase Real-Time Imbalance Energy Offset (RTIEO) and Real-Time Congestion Offset (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. 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. 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 addressed this issue. The first is lowering the transmission constraint relaxation parameter used in the scheduling run of the real-time dispatch. Lowering the $5,000/MWh parameter to $1,500/MWh along with other measures taken contributed to the reduction of real-time congestion costs. The 15 minute real-time market, implemented as part of the FERC Order 764 market changes initiative, addressed uplift resulting from price differences between the hour-ahead scheduling process and real-time dispatch. Aside from these completed initiatives, the flexible ramping product initiative will should further decrease real-time price spikes due to a shortage in ramping capability. In additional, the expanded full network model initiative will make modeling improvements in the day-ahead market to improve convergence between day-ahead and real-time modeled conditions. The ISO also plans to address tiered and/or voltage level based relaxation parameters in the planned "Stepped Transmission Constraints" initiative.

13.7 Preferred Resources Operating Characteristics (D)

Stakeholder Comment: PG&E notes that, the ISO and the CPUC have several efforts intended to define enhancements to RA requirements, including rules for counting resources for local RA, flexible and non-flexible or generic RA. Those efforts unfortunately lack an agreed or adopted quantitative framework for measuring the contribution of resources (supply or demand-side resource) towards RA requirements. As a result, enhancements to requirements and rules for measuring a resource's contribution towards those requirements are often done on an ad-hoc basis and without much coordination. Examples include:

- ISO's consideration of alternatives to transmission or conventional generation to address local needs.
- ISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation
- CPUC Energy Division's proposal for Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side DR Resources.
- ISO's deterministic and probabilistic assessment of system needs for generic and flexible capacity in the 2012 Long Term Procurement Plan (LTPP) Track 2, now closed but likely to be part of the next LTPP cycle.

PG&E recommends a parallel effort to develop analytical frameworks for measuring the system requirements for different types of capacity, quantifying the system need for different types of capacity (where need is the difference between system requirements and resources available to meet requirements), and calculating the contribution of different resources (supply and demand-side resources) to meet system requirements and needs. PG&E also recommends greater coordination among these efforts. (PG&E 2013)

Status: The ISO is working on the various topics listed above with stakeholders in the CPUC's LTPP, resource adequacy and demand response proceedings and in the ISO's "Reliability Services" stakeholder initiative.

13.8 Modify Resource Adequacy Replacement Rules (D)

Stakeholder Comment: Calpine notes, the CAISO currently enforces an unfair and inequitable replacement rule that violates the spirit of commercial transactions. This replacement rule, if applied to prospective flexible attribute procurement will multiply the harm. Specifically, if a Local RA resource is sold commercially to a counterparty as a lesser-value, System RA resource, the ISO requires that any replacement (due, for instance, to outage) must be with the higher-cost Local RA resource. This inequitable replacement obligation greatly complicates contracting and replacement given the dramatic oversupply of Local RA in some regions. The same difficultly will emerge if a Flexible RA requirement is approved by the CAISO and the CPUC. Simply put, Flexible RA sold as Generic, or System RA should not bear a replacement obligation with the higher quality product. (Calpine, NRG 2013)

Status: The topic is being addressed in the ISO's current "Reliability Services" stakeholder initiative.

13.9 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.[19]"

"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."

Status: The topic is being addressed in the ISO's current "Reliability Services" stakeholder initiative.

13.10 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.

Status: The topic is being addressed in the ISO's current "Reliability Services" stakeholder initiative.

13.11 Use-limited Resource 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 must offer obligations. 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.

Status: The topic is being addressed in the ISO's current "Reliability Services" stakeholder initiative.

13.12 Voluntary Preferred Resource 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

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

bilaterally procure additional local RA capacity that is needed to fulfill their local capacity procurement obligations. The ISO has also proposed a Joint Reliability Framework initiative (section 12.4), which includes a proposal for a backstop reliability services auction (RSA). The voluntary preferred resource auction would work in coordination with the RSA.

First, the voluntary demand response auction would be run as an initial procurement opportunity for preferred resources, and then bilateral procurement would occur, followed by the RSA for any requirements not met by procurement in the voluntary demand response auction or bilateral procurement. Initially the ISO would run a single product demand response only auction as a policy pilot and then expand the initiative to include additional preferred resources and multiple demand response products. In the expanded initiative the ISO could also consider expanding the auction beyond procurement of local reliability requirements.

Status: The ISO suspended this initiative because of CPUC efforts that addressed preferred resource procurement.

13.13 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.

Status: At the conclusion of its proceeding, the CPUC declined to adopt a seasonal LCR for 2012.

13.14 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.

Status: The ISO will address this issue in the "Bidding Rule" initiative and/or thorough business process manual changes, if needed.

13.15 Improve Transparency (D)

The CAISO Initiatives Catalog a few years back included a multi-stage data transparency initiative. The third stage was to create a process for further requests of information. This initiative would address and resolve ongoing data deficiencies such as:

- Ongoing reporting of MOC commitment volumes by hour and by constraint
- Ongoing reporting of residual unit commitment commitments by hour and by residual unit commitment-driver
- Ongoing reporting of units dispatched and held at minimum load, by driver.

Status: Should be deleted because this is a potential process improvement and not a market design initiative.

13.16 Protocol(s) for Simulation and Testing of New Models, Design Changes, or Products (D)

This initiative would develop standard protocols and parameters for testing and/or simulation of market bid/offer/take patterns for any market design change, change in modeling, or new product prior to implementation of the design change, modeling change,

or product. Although the ISO conducts testing and simulations for some design or model changes or new products, it does not have transparent, defined criteria for when testing and simulations are conducted or what protocols are applied. Establishing standard criteria, protocols, and parameters for testing and/or simulation would improve transparency in the ISO's markets and provide a systematic process for evaluating anticipated impacts of market modifications. (Six Cities 2013)

Status: Should be deleted because this is a potential process improvement and not a market design initiative.

13.17 Eliminate Unpriced Constraints (D)

The ISO uses constraints that affect market prices, but do not create a shadow price that is associated with that action (e.g., Minimum Online Capacity constraints do not create shadow prices.) The ISO has initiated the Contingency Modeling Enhancement initiative which will price some, but not all MOCs. This initiative would expose the purpose of each unpriced constraint on its system, enforce the constraint to protect reliability, and find a way to price it into the market. (Calpine 2013)

Status: This initiative is redundant with the "Extended Pricing Mechanism" initiative.

13.18 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 after the system flexible ramping product was in place and an enhancement to 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.

Status: The current "Flexible Ramping Product" stakeholder initiative will consider regional flexible ramping product requirements.

13.19 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.

13.20 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: This initiative should be deleted because this issue was mostly related to radially connected interties which will no longer exist under the expanded full network model.