Draft 2016 Stakeholder Initiatives Catalog and Roadmap

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1 Executive Summary

Each year the ISO publishes the Stakeholder Initiatives Catalog that details initiatives that have been proposed by the ISO and stakeholders. The catalog lists and describes ongoing and potential enhancements to the ISO market design, infrastructure planning, and generation interconnection process. The stakeholder initiatives catalog and roadmap process includes: 1) updating the status of current initiatives; 2) identifying new proposed initiatives; 3) classifying proposed initiatives as either discretionary or non-discretionary; and 4) prioritization of discretionary initiatives for consideration in the development of the policy initiatives roadmap for the coming year.

This year's catalog discusses the non-discretionary initiatives for that have already been identified for 2016, as well as other initiatives on which the ISO potentially could be working. Historically, the ISO has conducted a ranking process to prioritize the discretionary initiatives identified in the catalog. However, due to large number of non-discretionary initiatives planned for 2016 which include initiatives required to facilitate regional expansion of the ISO balancing authority area, the ISO will not be conducting a ranking process of discretionary initiatives in this cycle. The ISO believes that the current list of in progress, FERC mandated, and planned non-discretionary initiatives for 2016 will consume all of the ISO's policy development resources.

The following 13 stakeholder initiatives are currently underway.

1. Expanding Metering and Telemetry
2. Energy Imbalance Market Year 1 Enhancements
3. Interconnection Process Enhancements
4. Competitive Solicitation Process Enhancements
5. Flexible Ramping Product
6. Reactive Power Requirements and Financial Compensation
7. Reliability Services Phase 2
8. Bidding Rules Enhancements
9. Commitment Cost Enhancements Phase 3
10. Contingency Modeling Enhancements
11. Flexible RA Criteria and Must Offer Obligation Phase 2
12. Frequency Response Requirements
13. Energy Storage and Aggregated Distributed Energy Resources

The following five stakeholder initiatives are planned to start in late 2015.

1. Stepped Constraint Parameters
2. Two-Tier Allocation Real-Time Bid Cost Recovery
3. Fifteen-Minute Market Intertie Liquidity
4. Regional Transmission Access Charge Structure
5. Resource Adequacy Rules

The following six stakeholder initiatives are planned to start in 2016.

1. Regional Integration California Greenhouse Gas Compliance
2. Metering Rules Update
3. Full Network Model Enhancements
4. Real-Time Market Enhancements
5. Generator Contingency Modeling/Remedial Action Scheme Modeling
6. Transitional Implementation Items

The ISO welcomes stakeholder comments on the catalog and roadmap, as well as suggestions for items to be added to the catalog for consideration as potential future initiatives.

2 Plan for Stakeholder Engagement

Each year the ISO assesses identified initiatives through the stakeholder catalog for completeness and accuracy.

In prior years, the ISO has performed an analysis and ranked each discretionary initiative based on overall benefit and feasibility. However, given the number of initiatives already underway, the several FERC mandated initiatives that still must be addressed, and the need to conduct six new stakeholder initiatives to facilitate the regional expansion of the ISO, the 2016 catalog process will not include a ranking process as it has in prior years. Such an effort would result in the ISO and stakeholders spending time ranking/prioritizing discretionary items for 2016 that the ISO does not have the bandwidth to undertake. Instead, the 2016 catalog will document initiatives that will be undertaken during 2016, as well as initiatives that have not yet been undertaken and will be considered in future catalogs.

Stakeholders can comment on the completeness and accuracy of the initiatives specified in the catalog, and can request that additional initiatives be added to the catalog. Stakeholder comments submitted as part of this process should be submitted to initiativecomments@caiso.com.

Table 1 below shows the timeline and process to complete the 2016 Stakeholder Initiatives Catalog.

Table 1

Timeline and Process for 2016 Stakeholder Initiatives Catalog

Date	Milestones
Oct 7	Draft of Stakeholder Initiatives Catalog posted
Oct 15	Hold stakeholder call
Nov 4	Stakeholder comments due on draft catalog
Dec 15	Post final Stakeholder Initiatives Catalog

3 Introduction

The 2016 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 the ISO provides, the planning of transmission infrastructure, and the interconnection of generation. The catalog does not list process improvements or administrative changes that do not require a stakeholder process.

The catalog tracks policy changes and stakeholder initiatives that are considered completed when the stakeholder process ends (and typically results in the ISO's Board of Governors acting on the proposal). For more detailed scheduling and milestones for policy projects, see the Projected Stakeholder Initiative Milestones document.[1]

The catalog lists both market design and infrastructure and planning initiatives together. This creates a single, comprehensive directory of ongoing and potential stakeholder initiatives compiled from internal ISO staff and stakeholder suggestions.

Each section notes whether an initiative is in progress and its priority. The highest priority is a FERC mandated initiative followed by a non-discretionary initiative 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 based on its ability to provide reliability or economic benefits as compared to its costs. The catalog identifies each initiative 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 "rank-able" initiatives.

The *in progress* status code may be combined with any of the other three codes to show that a stakeholder initiative has begun and likely a webpage exists on the ISO stakeholder processes website.[2] "I, F" indicates that a FERC-mandated initiative is 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.

[1] Available at: http://www.caiso.com/Documents/ProjectedStakeholderInitiativeMilestones.pdf
[2] http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx

4 Initiatives completed since Previous Catalog

This section lists the initiatives where the policy development has been completed since the ISO published last year's Stakeholder Initiatives Catalog. The policy development is considered completed if the policy development stakeholder process is finished and the proposal has been approved by the ISO Board of Governors. Initiatives may still be progressing through other processes such as tariff development or awaiting FERC action. The list below includes initiatives approved by the Board through the September 17-18, 2015 Board meeting. This section does not include three policy initiatives that are being taken to the November 4-5, 2015 Board meeting (and these three initiatives are the first three initiatives listed in section 5.1).

4.1 Pay for Performance Regulation Year One Design Changes (D)

This initiative's primary objective was 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 was implemented in spring of 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. The "Pay for Performance Regulation Year One Design Changes" initiative examined modifying the methodology for calculating the mileage accuracy and revised the minimum performance standard.

The ISO's proposal was approved by the Board on November 13, 2014 and the ISO made a tariff amendment filing with FERC on December 2, 2014. A FERC order was received on January 30, 2015.

4.2 Pricing Enhancements (D)

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

This ISO's proposal was approved by the Board on December 18, 2014 and the ISO made a tariff amendment filing with FERC on July 14, 2015. A FERC order was received on September 14, 2015.

4.3 Capacity Procurement Mechanism (F)

This initiative designed a capacity procurement mechanism to replace the current backstop procurement mechanism that expires on February 16, 2016. The proposal included 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's proposal was approved by the Board on February 5, 2015, and the ISO made a tariff amendment filing with FERC on May 28, 2015. FERC issued an order approving the CPM proposal on October 1, 2015.

4.4 Reliability Services Phase 1 (D)

The Reliability Services initiative is a two-phase, multi-year effort to address the ISO's rules and processes surrounding resource adequacy (RA) resources. RSI phase 1 focused on RA rules and processes that must be updated for reliability or regulatory reasons.

The ISO's proposal was approved by the Board on March 26, 2015 and the ISO made a tariff amendment filing with FERC on May 29, 2015. FERC issued an order conditionally approving the RSI proposal on October 1, 2015.

4.5 Commitment Cost Enhancements Phase 2 (D)

This initiative narrowed the definition and criteria for "use-limited resources" to better align the category with the ISO's optimization. The revised use-limited definition is foundational to calculating opportunity costs in Commitment Cost Enhancements Phase 3. This initiative also created rule changes to more fully and accurately specify multi-stage generator costs to transition between configurations.

This ISO's proposal was approved by the Board on March 26, 2015 and the ISO made a tariff amendment filing with FERC on June 5, 2015. A FERC order was received on September 9, 2015 that accepted part of the filing and rejected part of the filing. FERC rejected the proposed changes to the use limited definition and is requiring the ISO to provide a more detailed definition. The ISO will develop these details in the Commitment Cost Enhancements Phase 3 stakeholder initiative and will refile with FERC.

4.6 Bid Cost Recovery and Variable Energy Resource Settlements (D)

The ISO proposed to modify existing financial settlement rules to ensure fair treatment of variable energy resources that provide economic bids to the ISO market. Second, applicable to all resource types, the ISO proposed some minor enhancements to the calculation of the bid cost recovery mitigation measures that are used to ensure a resource's bid cost recovery payment is only based on costs for energy that it actually delivered.

The ISO's proposal was approved by the Board on July 16, 2015. The ISO will make a tariff amendment filing with FERC.

4.7 Load Granularity Refinements (N)

The ISO and stakeholders evaluated alternatives for the level of granularity load should bid, schedule and financially settle in the ISO market. The ISO had 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.

The ISO made a filing with FERC on June 3, 2015 to maintain the current Default Load Aggregation Points. FERC has not yet responded to the filing.

4.8 Energy Storage Interconnection (D)

In 2013 the ISO conducted an effort to clarify interconnection rules for energy storage resources.

This effort concluded as a stakeholder initiative in 2014 and found that existing interconnection rules accommodate the interconnection of storage to the ISO controlled grid.

4.9 Natural Gas Pipeline Penalty Recovery (N)

In 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, the Board of Governors approved a provision that would allow generators to seek recovery, under limited circumstances, of natural gas pipeline penalties under the ISO bid cost recovery mechanism. The "Natural Gas Pipeline Penalty Recovery" initiative explored whether there is a need for the penalty cost recovery provision, or whether it should be modified, extended or withdrawn due to changed circumstances.

This initiative concluded that there was not a pressing need for the penalty cost recovery provision, and the ISO did not propose any tariff changes.

5 Planned Stakeholder Initiatives

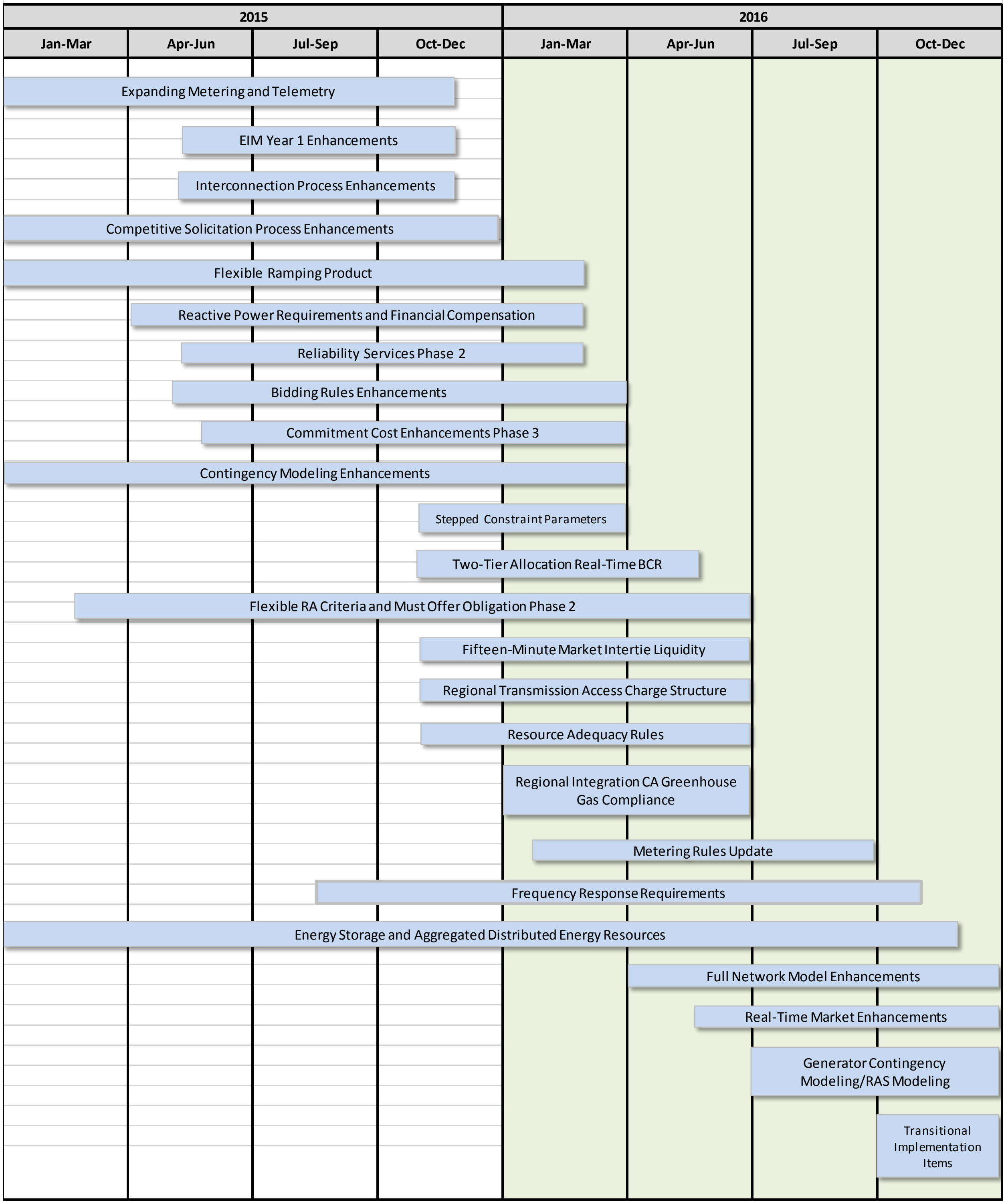
This section discusses stakeholder initiatives that are currently underway, are planned to start in late 2015, or are planned to start in 2016. Table 2 summarizes these planned initiatives and the timeline is shown in Figure 1 below.

Table 2
Planned Stakeholder Initiatives

#	Initiative	Timing
1	Expanding Metering and Telemetry	Currently Underway
2	Energy Imbalance Market Year 1 Enhancements	Currently Underway
3	Interconnection Process Enhancements	Currently Underway
4	Competitive Solicitation Process Enhancements	Currently Underway
5	Flexible Ramping Product	Currently Underway
6	Reactive Power Requirements and Financial Compensation	Currently Underway
7	Reliability Services Phase 2	Currently Underway
8	Bidding Rules Enhancements	Currently Underway
9	Commitment Cost Enhancements Phase 3	Currently Underway
10	Contingency Modeling Enhancements	Currently Underway
11	Flexible RA Criteria and Must Offer Obligation Phase 2	Currently Underway
12	Frequency Response Requirements	Currently Underway
13	Energy Storage and Aggregated Distributed Energy Resources	Currently Underway
14	Stepped Constraint Parameters	Planned to Start in Late 2015
15	Two-Tier Allocation Real-Time Bid Cost Recovery	Planned to Start in Late 2015
16	Fifteen-Minute Market Intertie Liquidity	Planned to Start in Late 2015
17	Regional Transmission Access Charge Structure	Planned to Start in Late 2015
18	Resource Adequacy Rules	Planned to Start in Late 2015
19	Regional Integration California Greenhouse Gas Compliance	Planned to Start in 2016
20	Metering Rules Update	Planned to Start in 2016
21	Full Network Model Enhancements	Planned to Start in 2016
22	Real-Time Market Enhancements	Planned to Start in 2016
23	Generator Contingency Modeling/Remedial Action Scheme Modeling	Planned to Start in 2016
24	Transitional Implementation Items	Planned to Start in 2016

Figure 1

Timeline for Planned Stakeholder Initiatives (Start and Stop Dates are Estimates)



5.1 Initiatives currently Underway

This section discusses stakeholder initiatives that are currently underway and have not yet been presented to the ISO Board for approval (as of October 7, 2015).

5.1.1 Expanding Metering and Telemetry (N)

In 2013, the ISO launched this initiative to address stakeholders' experiences and issues with the ISO's metering and telemetry requirements. The ISO worked with stakeholders to identify issues, business requirements and current rules, and specify business practice manual changes. Phase 1 of this initiative involved developing technical proposals to address five topic areas. In parallel to phase one implementation efforts, the ISO assessed the need to develop and advance a proposal for the use of data concentrators to provide distributed energy resource aggregation, data concentration, and control signal disaggregation services. This assessment resulted in the proposal enabling aggregated distributed energy resources to participate in the ISO market. Development of this proposal constituted phase two of the initiative.

In July 2015, the ISO Board approved the phase 1 proposal. The phase 2 proposal will be presented for approval at the November 4-5, 2015 Board meeting.

5.1.2 Energy Imbalance Market Year 1 Enhancements (I, F, D)

In November 2014, the ISO began this initiative 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 ISO Board approved phase 1 of this initiative in March 2015, and the proposal is pending FERC review. The phase 2 proposal will be presented for approval at the November 4-5, 2015 Board meeting.

5.1.3 Interconnection Process Enhancements (I, D)

The ISO is committed to continually reviewing potential enhancements to its generation interconnection process to reflect changes in the industry, improve processes, and better accommodate the needs of interconnection customers. In 2015, the ISO undertook an initiative that included refinements to the interactions with affected systems, established a time-in-queue criteria, and modifications that allow customers to change their projects and close some loop holes.

The ISO took most elements of this initiative to the Board for approval in September 2015. The two remaining elements (Phase 2) will be presented to the Board for approval at the November 4-5, 2015 Board meeting.

5.1.4 Competitive Solicitation Process Enhancements (I, D)

On March 6, 2014 the ISO had a stakeholder meeting to discuss "lessons learned" from the 2012-2013 transmission planning process competitive solicitations. The ISO has made several changes and looks forward to making further process improvements and increase stakeholder solicitation.

The ISO is currently in the process of reviewing stakeholder comments and additional rounds of stakeholder engagement will follow as needed. To the extent that any of its proposals require tariff amendments, the ISO is targeting the December 17-18, 2015 Board meeting to present a proposal to the Board.

5.1.5 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. The flexible ramping product will help the system to maintain and use dispatchable flexibility. The flexible ramping product is the 5-minute ramping capability, which will be dispatched to meet 5- minute to 5-minute net system demand changes, or net system movement in RTD.

The ISO is planning to present the Flexible Ramping Product proposal at the February 3-4, 2016 Board meeting.

5.1.6 Reactive Power Requirements and Financial Compensation (I, N)

Through this initiative the ISO will develop a requirement for asynchronous resources to provide reactive power, which will replace the current system impact study assessment approach. This initiative will also explore financial compensation for resources.

The ISO will post a revised straw proposal in October 2015 and will seek Board approval of a proposal at the February 3-4, 2016 Board meeting.

5.1.7 Reliability Services Phase 2 (I, N)

This initiative will include elements that were discussed, but not concluded, in the Reliability Services Phase 1 stakeholder initiative, as well as new elements to further improve the resource adequacy program.

The ISO will post a revised straw proposal in October 2015. The ISO plans to present a proposal to the Board in Q1 2016.

5.1.8 Bidding Rules Enhancements (I, N)

This initiative involve re-evaluating 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 other ISOs/RTOs and would potentially improve the consistency between the day-ahead and real-time markets, as well as further increase safeguards against market manipulation.

This initiative is in the early phase of the stakeholder process. The ISO plans to present its proposal for approval at the March 24-25, 2016 Board meeting.

5.1.9 Commitment Cost Enhancements Phase 3 (I, D)

This initiative focuses on developing and implementing an opportunity cost model for use-limited resources that cannot be optimized by ISO commitment process due to non-economic operational limitations as set forth by statute, regulation, ordinance, or court order.

The ISO has conducted a technical workshop and released a straw proposal in August 2015. The ISO plans to present its proposal for approval at the March 24-25, 2016 Board meeting.

5.1.10 Contingency Modeling Enhancements (I, N)

The ISO has been using 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 arises from 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 ISO will be resuming this initiative and plans to present its proposal for approval at the March 24-25, 2016 Board meeting.

5.1.11 Flexible RA Criteria and Must Offer Obligation Phase 2 (I, D)

In this initiative, the ISO is proposing enhancements to the existing flexible capacity framework. Specifically, the ISO will propose solutions to address the growing concern with over-generation. The primary focus is managing the Pmin burden and the interplay between quantities of inflexible capacity and ramping capability provided by RA resources, particularly in non-summer months. The ISO will assess issues pertaining to hourly net load ramps, in addition to the already established three hour net load ramps. Lastly, the ISO will assess the potential impacts self-scheduled non-RA resources may have on the challenges of over-generation.

The ISO started this initiative in June 2015 by releasing an issue paper outlining the scope of this effort. The ISO will host a series of working groups over the course of Q3 2015 and commence a formal stakeholder process in Q4 2015. The ISO plans to present a proposal to the Board in Q2 2016.

5.1.12 Frequency Response Requirements (I, 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 comply 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 address this emerging operational need, the ISO may also consider additional products or services necessary to maintain system inertia within this initiative.

The ISO will post a revised straw proposal in October 2015 and plans to present a proposal to the Board at the February 3-4, 2016 Board meeting.

5.1.13 Energy Storage and Aggregated Distributed Energy Resources (I, D)

This initiative focuses on enhancing the ability of grid-connected storage and distribution-connected resources to participate in the ISO market. This initiative consists of two phases: (1) issues for potential policy resolution in 2015; and (2) issues for potential policy resolution in 2016 and beyond. The 2015 scope comprises three topics: a limited set of enhancements to the ISO non-generator resources model, a limited set of enhancements to the ISO proxy demand resource and reliability demand response resource models, and addressing questions associated with some non-resource adequacy multiple use applications. A more extensive set of issues will be addressed in the second phase of this initiative in 2016.

The objective is to bring proposed resolutions to identified policy issues in the 2015 scope to the Board by December 2015.

5.2 Initiatives planned to start in Late 2015

This section describes stakeholder initiatives that will be started in late 2015.

5.2.1 Stepped Constraint Parameters (F)

This initiative will consider changes to the way the ISO market applies penalty prices to certain constraints in the market: (1) the power balance constraint: (2) transmission constraints: and (3) energy imbalance market transfer constraints. These changes would apply different penalty prices for infeasibilities depending on the level of constraint relaxation or potentially other criteria. FERC previously encouraged the ISO to pursue changes to the transmission constraint relaxation parameters as part of its order changing the transmission constraint penalty price from $5,000/MWh to $1,000/MWh.

This initiative is planned to start in November 2015.

5.2.2 Two-Tier Allocation Real-Time Bid Cost Recovery (F)

This initiative is one of six market design enhancements that FERC, in its September 21, 2006 MRTU order allowed 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 and requested that the ISO implement a two tier charge similar to day-ahead bid cost recovery where the first tier allocates costs based on cost causation principles.

FERC granted the ISO's request for an extension of time to April 30, 2017 to implement this functionality. This initiative will start in November 2015.

5.2.3 Fifteen-Minute Market Intertie Liquidity (D)

This initiative will address the following issues: neighboring balancing authority areas may not be supporting 15-minute schedule changes: difficulty in procuring transmission in 15-minute blocks: the absence of bilateral trading at a 15-minute granularity; and reticence of resource owners to adjust their output within the hour. A workshop is scheduled for October 6, 2015 with the goal of helping the ISO and stakeholders understand the causes of low import/export 15-minute market liquidity. The ISO will use the information gathered at the workshop to identify potential market design changes to be addressed in a subsequent stakeholder initiative.

This initiative is planned to start in November 2015.

5.2.4 Regional Transmission Access Charge Structure (D)

To address regional expansion of the ISO, it is appropriate for the ISO to consider whether its current regional transmission access charge (TAC) structure should remain as it is presently designed or be revised. In this initiative, the ISO will explore different options for revising the TAC structure, as well as the option of not changing it, to determine how best to align cost allocation with benefits and fairly consider the interests of affected parties.

This initiative is planned to start in November 2015.

5.2.5 Resource Adequacy Rules (D)

To address regional expansion of the ISO, the ISO will need to evaluate the applicability of a resource adequacy program on a regional basis. This initiative would evaluate tariff provisions appropriate to encompass additional states.

This initiative is planned to start in November 2015.

5.3 Initiatives planned to start in 2016

This section describes stakeholder initiatives that are planned to start in 2016.

5.3.1 Regional Integration California Greenhouse Gas Compliance (D)

To address regional expansion of the ISO, this initiative will determine how costs for generation to comply with California's greenhouse gas regulations will be treated in the ISO's integrated forward market (IFM). The Energy Imbalance Market currently has a methodology that enables generation resources to include GHG compliance costs in their offers to supply California load. Similar provisions must be developed for the integrated forward market to address GHG compliance costs for new PTOs outside of California.

This initiative is planned to start in January 2016.

5.3.2 Metering Rules Update (D)

To address regional expansion of the ISO, in this initiative the ISO will review the current metering tariff provisions and make enhancements to ensure that the ISO's metering requirements meet operational needs and do not impose unnecessary barriers or costs on market participants. The ISO tariff contains two approaches to provide revenue metering data. In many cases, these provisions have not been updated since the ISO began operations. However, technology improvements offer the ability to convey the necessary data with appropriate security and at a lower cost.

This initiative is planned to start in February 2016.

5.3.3 Full Network Model Enhancements (D)

To address regional expansion of the ISO, this initiative will resolve policy issues on how to model imports and exports at their actual source and sink to improve accuracy of settlements and enforce physical flow constraints. This initiative will include modeling ISO market imports and exports using physical sources and sinks located throughout the WECC 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, and modeling of additional balancing authority areas in the WECC.

This initiative is planned to start in April 2016.

5.3.4 Real-Time Market Enhancements (D)

This initiative will examine market design changes that would be needed as part of using the ISO market's five-minute real time dispatch market functionality to perform many of the functions that are now performed by the ISO market's 15-minute real time unit commitment functionality. These functions would include real-time unit commitment, ancillary services procurement, 15-minute market scheduling and pricing, and local market power mitigation. The 15-minute market would continue to schedule interties and internal resources at 15-minute granularity but would be able to be run with a shorter lead time. Along with these changes, the ISO could consider extending the short-term unit commitment process to have a longer look-ahead period, enabling it to commit resources that have a start-up time longer than five hours and to more optimally commit all resources, particularly those with limited starts.

This initiative is planned to start in June 2016.

5.3.5 Generator Contingency Modeling/Remedial Action Scheme Modeling (N)

This initiative would modify the ISO's current spinning reserve and non-spinning reserve products so they can be procured more granularly than the existing ancillary service zones. This would provide greater assurance of deliverability of contingency reserves and ensure that the ISO can recover from a generation contingency within the 10-minute requirement. This initiative will also address Ancillary Services substitution, in which 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 to address the possibility of added flexibility for substitution of the source of ancillary services in future releases of market design enhancements.[3] The ISO will need to make any filing by April 30, 2017 to demonstrate that the ISO does not need it or to propose market rules.

This initiative is planned to start in July 2016.

5.3.6 Transitional Implementation Items (D)

To address the regional expansion of the ISO, there may be transitional issues that need to be vetted and understood to develop a transition plan when a new entity wants to join the ISO. These issues may include transmission interconnection processes, source of load forecast information to use for areas external to California, and new operating procedures to transition transmission lines to ISO operational control. This initiative is planned to start in October 2016.

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[3] Paragraph 303
http://www.caiso.com/Documents/September21_2006OrderConditionallyAccepting2_9_06MRTUfilinginDocketNos_ER06-615-000andER02-1656-027_etal_.pdf

6 Initiatives not currently planned to be Started

This section describes the stakeholder initiatives identified either by the ISO or stakeholders that the ISO is not planning to start work on in 2015 or 2016.

Each initiative in this section is grouped within 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, may affect other markets and products and vice versa.

6.1 Day-Ahead Market

The ISO's day-ahead market consists of the integrated forward market (IFM) and the residual unit commitment" (RUC) process. The structure and rules for the day-ahead market are presented in the business practice manuals for market operations and market instruments.

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

This initiative is one of six market design enhancements that the FERC, 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. FERC has granted the ISO's request for an extension of time to April 30, 2017.

6.1.2 Marginal Loss Surplus Allocation Approaches (D)

Since the start of the new ISO market design, the ISO has allocated the marginal loss surplus based on measured demand. This methodology was accepted by FERC in its September 21, 2006 MRTU order. In filed comments on the ISO MRTU Tariff, PG&E expressed concerns regarding 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. Using data from the first year of operation after the start of MRTU, the October 2010 report found that allocation based on measured demand did not lie within the bounds of alternative methodologies. Based on these results, the ISO agreed to further analysis using "data covering the period after April 1, 2010, which will further inform the stakeholder process." To inform the process, the ISO will need to release an update to the October 2010 report.

6.1.3 Combine IFM/RUC with Multi-Day Unit Commitment (D)

This initiative consists of combining the integrated forward market (IFM) and the residual unit commitment processes (RUC), while optimizing the integrated forward market over multiple days. Integrating the IFM and RUC allows the market optimization to consider the ISO's demand forecast in the market's clearing of bid-in demand. This increases the efficiency of the IFM and RUC solutions because they are co-optimized. Having the IFM that looks out two to three days would create more efficient commitment decisions that better reflect whether resources are expected to run for a single or multiple days. In addition, this initiative would consider allowing RUC to de-commit resources to better handle increasing amounts of generation and manage the potential for over-generation because of increased amounts of variable energy resources. 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. In 2011, the ISO completed the 72-Hour Residual Unit Commitment initiative, which was an interim step that will provide some benefits until the full multi-day unit commitment solution can be implemented.

6.1.4 Multi-Stage Generator Bid Cost Recovery (D)

In 2014, the 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. 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 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.

6.2 Real-Time Market

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 than the RTUC process. For more details regarding the real-time market, refer to the business practice manuals for market operations and market instruments.[4]

6.2.1 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. An example of an extended pricing mechanism is the Midwest ISO's "extended locational marginal pricing (LMP)."

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

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.

6.2.2 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 which is in line with the Market Surveillance Committee’s opinion on the bid cost recovery rule changes wherein it suggests that "separable decisions" should receive separate bid cost recovery. One possibility is to afford separate bid cost recovery to separate commitments of short-start units in the real-time market.

6.2.3 Multi-Stage Generator Refinements (D)

This initiative was added to the catalog by the ISO in September 2015. When there is low hydro availability, ISO operations leans more heavily on the thermal units on AGC which requires more realistic regulation modeling for the thermal units. One advantage of the MSG model is if a plant could provide regulation at different configurations, every configuration could have its own regulation bid price and regulation ramp rate.

6.3 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.

6.3.1 Consideration of Non-RA Import Energy in RUC Commitment Process (D)

Early in the MRTU stakeholder process there was a suggestion that the residual unit commitment process consider non-resource adequacy import energy bids that did not clear the integrated forward market. RUC potentially could 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.

6.4 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.

6.4.1 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. The ISO will consider undertaking the second phase of the initiative to address how the ISO procures and compensates blackstart capability and allocates cost to the market.

6.4.2 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.

6.4.3 Regulation Service RT Energy Make Whole Settlement (D)

This initiative would examine whether 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.

6.5 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.

6.5.1 CRR Modifications (D)

During 2014, the ISO experienced significant revenue inadequacy of congestion revenue rights. 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. This initiative would address any additional changes that may be warranted to address revenue inadequacy.

6.5.2 Economic Methodology for Transmission Outages (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. This initiative would develop criteria so 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. 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. The operating transfer capability duration curve methodology which was approved by the Board in June 2011 has addressed the revenue inadequacy problem on the interfaces, for the most part, but outages on internal transmission paths can contribute significantly to the revenue inadequacy problem. The ISO will continue to monitor this issue and determine if further steps are needed.

6.5.3 Flexible Term Lengths of Long Term CRRs (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: (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 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.

6.5.4 Insufficient CRR Hedging (D)

This initiative was suggested by CDWR. CDWR wrote: "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 market participants' historical load…."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."

6.5.5 Long Term CRR 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.

6.5.6 Multi-Period Optimization for Long-Term CRRs (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.

6.5.7 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 that other ISOs have more specific rules on outage reporting requirements, including notice of such known outages up to one year in advance.

6.5.8 Review CRR 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 (I, F) 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.

6.5.9 CRR Allocation (D)

CDWR requests that CAISO introduce an initiative to revise the methodology used for allocating congestion revenue rights sourced at the trading hubs. CDWR believes that the current methodology contributes to the ongoing revenue imbalance of the congestion revenue right balancing account and is counterproductive to the stated purpose for CRRs.

6.6 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.

6.6.1 Allowing Convergence Bidding at CRR Sub-Load Aggregation Points (D)

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

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

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. 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.

6.6.3 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. This initiative would 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.

6.7 Resource Adequacy

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.

6.7.1 Simplified Reporting of Forced Outages (D)

PG&E recommends adopting a more streamlined forced outage reporting requirement, creating uniform forced outage reporting criteria and eliminating the Standard Capacity Product (SCP) incentive mechanism for small resources.

6.7.2 Energy Products Delivered on Interties (D)

As suggested by Powerex, this initiative would clarify the tariff with respect to energy products. It would define the different energy products that the ISO purchases on the interties, define the performance obligations under each product, and clarify how the procurement of each product type affects measures the ISO will take to ensure reliability, including procurement of RUC, flexible ramping product, or other measures.

6.7.3 Multi-Year RA Import Allocation Process (D)

This initiative would establish a multi-year RA import allocation process. The ISO will consider this initiative in conjunction with the multi-year RA obligation framework being considered by the CPUC as part of the Joint Reliability Plan.

6.7.4 Review of Maximum Import Capability Methodology (D)

Stakeholders 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. The initiative may also consider an enhancement to the MIC approach for delivery when delivery may not need to occur simultaneous with bulk energy delivery.

6.7.5 Reallocation of MIC between Electrically Adjacent Import Paths (D)

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.

6.7.6 Allocation of MIC among Load Serving Entities (D)

Stakeholders have suggested that the current MIC methodology is an economically inefficient process because 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 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. This initiative would consider this allocation question.

6.8 Infrastructure and Planning

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

6.8.1 Transmission Interconnection Process (D)

Although the ISO's tariff currently 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.

6.9 Other

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

6.9.1 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.

6.9.2 Integrated Optimal Outage Coordination (D)

The ISO would examine including economic criteria for approving or rejecting planned outage repair requests.

6.9.3 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 ensure fair compensation.

6.9.4 Storage Generation Plant Modeling (D)

PG&E has requested that an initiative be devoted to the proper modeling of pumped storage units. This would impact not only PG&E's Helms units, but other market participants who use or are considering the use of this type of generation.

6.9.5 Multiple Resource IDs per Generation Meter (D)

Many renewable resources have multiple off-takers and the CAISO's current system limitation of a single Resource ID per meter reportedly hampers participant's ability to submit economic bids. The CAISO would have to change its tariff and system configuration to allow modeling of multiple "pseudo-generators" with independent Resource IDs to enable each off-taker to submit separate bids.