2017 Stakeholder Initiatives Catalog

Prepared by
Market and Infrastructure Development

September 15, 2016

Table of Contents

1 Introduction

This *2017 Stakeholder Initiatives Catalog* documents current, planned, and potential stakeholder initiatives to develop enhancements to the California ISO market, infrastructure and planning policy. This creates a single, comprehensive directory of ongoing and potential policy initiatives. This catalog lists initiatives that require a stakeholder process and for which the completed policy typically requires tariff changes. It does not list process improvements or administrative changes.

The stakeholder initiatives catalog process includes making various updates to this catalog:

1. Updating the status of listed initiatives;
2. Identifying new proposed initiatives and deleting listed initiatives that are no longer relevant or are otherwise obsolete; and
3. Classifying listed initiatives into various categories that determine their priority, as described in section 3, below.

This catalog organizes initiatives into the following sections:

- Initiatives Completed Since Previous Catalog
- Initiatives Currently Underway and Planned
- Discretionary Initiatives
  - ❖ General Market Products
  - ❖ Day-Ahead Market
  - ❖ Real-Time Market
  - ❖ Energy Imbalance Market
  - ❖ Market Products
  - ❖ Congestion Revenue Rights
  - ❖ Convergence Bidding
  - ❖ Resource Adequacy
  - ❖ Infrastructure and Planning

The *2017 Stakeholder Initiatives Catalog* is then used in conjunction with the development of the *2017 Policy Initiatives Roadmap* which will consist of policy initiatives the ISO will undertake in 2017 and the approximate timeframes. During the development process of the roadmap, the ISO performs an analysis and ranks each discretionary initiative based on overall benefit and feasibility.

The roadmap development process will consist of*:*

1. Ranking of discretionary initiatives for consideration in the development of the policy initiatives roadmap;
2. Review stakeholder input of the rankings of discretionary initiatives and revising initiatives as necessary;
3. Finalizing the ranked discretionary initiatives; and
4. Publishing the final *2017 Policy Initiatives Roadmap.*

Unlike last year, the ISO will perform an analysis and ranking of each discretionary initiative. The ISO will post a more detailed explanation of the ISO's analysis and ranking process in a separate document after it finalizes the *2017 Stakeholder Initiatives Catalog*.

2 Plan for Stakeholder Engagement

The following table outlines the proposed schedule to complete the *2017 Stakeholder* Initiatives *Catalog* and *2017 Policy Initiatives Roadmap*.

Stakeholder Process Schedule	
Date	**Milestones**
Sep 15	Post draft *2017 Stakeholder Initiatives Catalog*
Sep 29	Stakeholder written comments due regarding clarification, proposed initiatives not listed in catalog, and proposed deletions.
Oct 19	Post revised *2017 Stakeholder Initiatives Catalog* and the ISO's proposed initial ranking of discretionary initiatives.
Oct 25	Stakeholder call
Nov 10	Stakeholder written comments due regarding the ISO's ranking of initiatives.
Nov 30	Post *2017 Policy Initiatives Roadmap*
Dec 7	Stakeholder call
Dec 21	Stakeholder written comments due regarding the *2017 Policy Initiatives Roadmap*
Feb 1, 2017	Present *2017 Policy Initiatives Roadmap* to the EIM Governing Body
Feb 15, 2017	Present *2017 Policy Initiatives Roadmap* to the Board of Governors

For the stakeholder comments due September 29, the ISO requests stakeholder written comments regarding any of the following:

1. Questions or clarifications regarding initiatives in the catalog;
2. A detailed description of any proposed new initiatives, including an explanation of how it would improve market efficiency and/or grid reliability, and when it needs to be addressed; and
3. A detailed explanation why the ISO should delete an initiative listed in catalog or why the ISO should not delete an initiative it proposes to be deleted.

Stakeholders should submit their comments to initiativecomments@caiso.com by the close of business on Thursday, September 29, 2016.

3 Initiative Categorization

This catalog categorizes initiatives into various categories used in determining their priority. The catalog identifies the category each initiative falls into with a letter code found next to its title.

The codes are:

I – In-progress initiatives;

F – FERC-mandated initiatives;

N – Non-discretionary initiatives; and

D – Discretionary or "rank-able" initiatives

The highest priority are in-progress initiatives. The next highest priority are FERC mandated initiatives the ISO must complete to comply with FERC orders. The third highest priority consists of non-discretionary initiatives, which the ISO tries to use sparingly, consists of initiatives 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 or EIM Governing Body.

The final designation is a discretionary initiative, which may be prioritized or "ranked" by the ISO considering the design or policy change's reliability or economic benefits balanced against implementation feasibility.

The *in progress* status code may be combined with any of the other three codes to show that a stakeholder initiative has begun and a webpage likely exists on the ISO stakeholder processes website.[1] "I, F" indicates that a FERC-mandated initiative is going through a stakeholder process.

In addition to these codes, this document also includes the following codes for initiatives whose policy may affect the Energy Imbalance Market:

E1 – EIM Governing Body's primary authority

E2 – EIM Governing Body's advisory role

E3 – EIM Governing Body's hybrid- primary authority

E4 – EIM Governing Body's hybrid- advisory role

An E1 classification is any policy initiatives that involve market rules changes that fall entirely within the EIM governing body's primary authority[2]. An E2 classification is any policy initiatives that involve market rules changes that fall entirely within the advisory authority of the EIM governing body[3]. An E3 classification is when the primary driver for the initiative is the EIM and

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

the policy initiative is a hybrid because there is a component that would fall within the EIM's governing body's primary authority and a component that would fall within its advisory authority[4]. An E4 classification is when the primary driver for the initiative is not the EIM and the policy initiative is a hybrid in that it has both a component that would fall within the EIM governing body's primary authority and a component that would fall within its advisory authority[5].

The role of the EIM Governing Body will differ depending on which of these classifications applies to proposed policy changes[6]. Stakeholders should consider the EIM classification codes listed in this document as preliminary. The ISO will be conducting a stakeholder initiative beginning in early October to develop a guidance document that will provide detail as to how the ISO will determine which of these classifications an initiative falls into.

4 Initiatives Completed Since Previous Catalog

This section lists the initiatives where the policy development has completed since the ISO published last year's Stakeholder Initiatives Catalog. Policy development is completed when the stakeholder process is finished and the proposal has been approved by the ISO Board of Governors. Initiatives placed in this section may still be currently underway, but will be approved by the ISO Board of Governors by December 2016. Initiatives may also still be progressing through other processes such as tariff development or awaiting FERC action.

For additional information on initiatives underway, please refer to the stakeholder initiatives web page.7

4.1 Flexible Ramping Product (N)

This initiative enhanced the real-time market design. The flexible ramping product compensates resources for providing ramping capability as well as incentivizes loads, resources, and interties to reduce the significant ramps illustrated by the well-known “duck curve” diagram. If load or supply resources increase the forecast ramp, the market charges the load or supply resource for the flexible ramping product. If load or supply resources decrease the forecasted ramp, the market compensates the load or supply resource. In addition, the flexible ramping product procures additional ramping capacity to meet uncertainty in the net load8 forecast when it is economic to do so. The market allocates the cost for the flexible ramping product to cover uncertainty based on a load or supply resources forecast error.

The design significantly improved the management of ramping capacity in the real-time market. As a result, the environmental policy goals across the West can be achieved more efficiently and economically.

This initiative was approved by the Board of Governors on February 3, 2016.

[4] Ibid.
[5] Ibid.
[6] http://www.caiso.com/Documents/CharterforEnergyImbalanceMarketGovernance.pdf
[7] http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx
[8] Net load is gross load less wind and solar resource output.

4.2 Energy Storage and Aggregated Distributed Energy Resources – Phase 1 (D)

This initiative increased the ability for distributed energy resources to participate in the ISO market. Several enhancements to existing market design rules were created such as enhancements to the market participation model for storage and demand response performance measures. The storage-related enhancements enabled non-generator resources to submit a daily state of charge bidding parameter and to have the option to self-manage limits and state of charge. The demand response-related enhancement provided three performance evaluation methods for a proxy demand resource or reliability demand response resource with behind-the-meter generation devices.

This initiative was approved by the Board of Governors on February 3, 2016.

4.3 Reactive Power Requirements and Financial Compensation (N)

This initiative applied a uniform requirement for non-synchronous generators to provide reactive power capability as a condition of interconnection. It also required nonsynchronous generators to install automatic voltage control systems, which is necessary in order for generators providing reactive power to maintain voltage schedules. The ISO explored modifications to the financial compensation related to reactive power and voltage support and determine no changes were necessary at this time.

This initiative was approved by the Board of Governors on August 31, 2016.

4.4 Bidding Rules Enhancements (N)

This initiative considered enhanced ISO market bidding rules and refined commitment cost calculations for generator minimum load costs. This initiative included re-evaluating market 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 also re-evaluated the current rules that allow resources unrestricted flexibility to submit different energy bid prices across hours in the real-time market. These potential changes were 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.

The ISO combined this issue with *Commitment Cost Enhancements – Phase 3,* which was approved by the Board of Governors on March 25, 2016 under the title *Commitment Cost Bidding Improvements*.

4.5 Accounting of Minimum Load Costs (N)

This initiative was one part of the Bidding Rules Enhancements initiative that the ISO spun off to go separately to the ISO Board of Governors in February 2016. In April 2015, the ISO prioritized modifying how minimum load costs in the event a generator has to change its minimum operating level are accounted for in the market. Minimum load costs consist of the cost of operating a facility at or below its minimum operating level and are paid for through the bid cost recovery process to the extent energy revenues do not cover those costs. The market software also considers these costs in creating the optimal dispatch for the system. Currently, minimum load costs are not adjusted when a generator's minimum operating level changes, which can result in the inefficient dispatch of the generator.

One of the primary reasons a generator's minimum operating level changes is varying temperatures over the day. Without new rules to address minimum load costs when ambient conditions result in a significant change to a generator's minimum operating level, there is a risk that the ISO market systems may dispatch these resources inefficiently. This risk is likely to be greatest during the summer months.

This initiative was approved by the Board of Governors on February 3, 2016. The ISO implemented the proposed enhancements prior to summer 2016 operations.

4.6 Commitment Cost Enhancements - Phase 3 (N)

This initiative developed a market based methodology to optimally commit use-limited resources and provide more effective risk management tools while maintaining reliability. It revised the definition of "use-limited" resource to align it with resources that need an opportunity cost included in their commitment costs to be efficiently dispatched given limitations that extend beyond the market optimization horizon. It also provided market participants greater flexibility to reflect preferred operating values in the ISO's master file, including maximum daily starts, maximum daily multi-stage generator transitions, and ramp rates.

The ISO combined this issue with *Bidding Rules Enhancements,* which was approved by the Board of Governors on March 25, 2016 under the title, *Commitment Cost Bidding Improvements*.

4.7 Frequency Response Requirements – Phase 1 (F)

This initiative addressed the January 2014 FERC approval of new frequency response requirements for balancing authority areas proposed by the North American Electric Reliability Council (NERC). The ISO assessed its current frequency response capabilities and historical frequency response rates and compared them to the new NERC requirements. The analysis showed that the ISO could, at times, be short of its required share of frequency response. In particular, when there is high renewable output and low load levels, there may not be sufficient frequency-responsive resources on-line to meet the new NERC requirement. Management proposed a two phased initiative process to ensure the ISO has sufficient frequency response capabilities to meet the new standard. The first phase provides a short-term solution that can be implemented by December 1, 2016.

This initiative was approved by the Board of Governors on March 25, 2016.

4.8 Aliso Canyon Gas Electric Coordination Measures (N)

This initiative proposed a coordinated set of operational tools and market enhancements to address limitations resulting from the loss of the Aliso Canyon gas storage facility. The operational tools enabled ISO operators to manage gas usage of generators in southern California to address reliability issues on the gas system. These tools were designed to reflect gas limitations in the ISO market and to minimize electric generation dispatch that would otherwise operate outside gas system limitations. This avoided further exacerbating gas system conditions and contributing to the likelihood that gas curtailments would result in the disruption of electric service in the area. The market enhancements provide generators greater ability to reflect gas system limitations and gas prices in their bids submitted to the ISO market. These enhancements resulted in the ISO market dispatching generation in a way that is consistent with gas system limitations to maintain reliability.

This initiative was approved by the Board of Governors on May 4, 2016.

4.9 Congestion Revenue Right Clawback Rule Modification (D)

This initiative developed modifications to the congestion revenue right clawback rule. This rule was designed to prevent market participants from using virtual bids to inflate congestion revenue right payments. The first modification was designed to increase incentives to economically re-bid imports and exports in the real-time market. The modification specifies import and export reductions that are the result of an economic bid that meet specified criteria will not result in clawback of congestion revenue right payments. The second rule addressed a loophole in the clawback rule. Virtual bids at default load aggregation points and trading hubs would no longer be exempt from the settlement rule.

This initiative was approved by the Board of Governors on June 28, 2016.

4.10 Aliso Canyon – Phase 2 (N)

This initiative evaluates which temporary provisions established in the Aliso Canyon Gas Electric Coordination Measures initiative are needed to continue successfully managing reliability. In addition, the initiative will determine if refinements needed and provide greater transparency.

The ISO plans to seek approval from the Board of Governors at the October 3, 2016 meeting.

4.11 BCR Self Schedule Allocation and Bid Floor (D, E2)

This initiative evaluates two relatively minor refinements that allows the ISO market to more efficiently address potential oversupply exacerbated by increased amounts of variable energy resources. The measures end the current exemption from the allocation of bid cost recovery costs for load met by day-ahead generation self-schedules, and lowering the energy bid floor from -$150 to -$300.

The ISO plans to seek approval from the Board of Governors at the October 26-27, 2016 meeting.

4.12 Reliability Services - Phase 2 (N)

This initiative addresses various enhancements to resource adequacy rules, such as finalizing substitution rules for temporarily unavailable resources, and processes and timelines for various resource adequacy sufficiency calculations the ISO performs.

The ISO plans to seek approval from the Board of Governors at the October 26-27, 2016 meeting.

4.13 Load Serving Entity Definition Refinement (D)

This initiative refines the tariff definition of “load serving entity” to include entities that have been granted authority by state or local law, regulation or franchise to serve their own load directly through wholesale energy purchases. The current definition only includes entities that serve retail load. The impact to congestion revenue right allocation and resource adequacy requirements will also be addressed.

The ISO plans to seek approval from the Board of Governors at the October 26-27, 2016 meeting.

5 Initiatives Currently Underway and Planned

This section discusses stakeholder initiatives that are currently underway and will not be presented to the ISO Board for approval by December 2016.

5.1 Contingency Modeling Enhancements (I, N)

This initiative is exploring a market mechanism to prepare the ISO balancing authority area for system contingencies on major transmission lines for which the ISO must restore flows to within operating limits within 30 minutes. These measures would reduce exceptional dispatches and replace most minimum online constraints. It would also implement a separate payment to resources that provide “corrective capacity”. This initiative may change the congestion revenue rights allocation, auction, and settlement as it relates to the contingency modeling enhancements.

5.2 Generator Interconnection Driven Network Upgrade Cost Recovery (I, N,)

The ISO tariff requires Participating Transmission Owners (PTOs) to reimburse generator interconnection customers for certain network upgrades. These network upgrade costs are included in their customer rate bases through transmission access charges. Customers of PTOs with a relatively small rate bases could experience significant rate increases from generator driven low voltage network upgrades. This initiative will explore potential changes to the current network upgrade cost recovery mechanism.

5.3 Bid Cost Recovery Enhancements (F, E2)

This initiative addresses two 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.

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, rather it 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 evaluates the appropriateness, and potentially the design, of bid

I – In progress; F – FERC-mandated; N – Non-discretionary; D – Discretionary;
E1 – EIM GB Primary; E2 – EIM GB Advisory; E3 – EIM GB Hybrid Primary; E4 – EIM GB Hybrid Advisory

cost recovery calculations reflect run times that cross operating days. FERC has granted the ISO's request for an extension of time to submit a tariff filing by April 30, 2017.

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

The ISO decided to re-scope this initiative to focus on issues directly related to the definition of flexible capacity and flexible capacity product enhancements, including flexible capacity from import and pumped hydro resources. The ISO will also conduct an assessment of the existing flexible capacity product to determine if any additional enhancements are needed.

5.5 Transmission Access Charge Options (I, 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.

5.6 Review Transmission Access Charge Billing Determinant (I, D)

This initiative is analyzing the current transmission high voltage access charge structure. The ISO currently recovers the costs for transmission facilities above 200 kV from all loads in its balancing area. This "postage stamp" rate does not distinguish among project types for purposes of cost allocation; e.g., reliability, economic or policy. Extension of this structure without modification would result in a cost shift of existing ISO facilities to other states and the sharing of new facility costs among states without express consideration of benefits. Accordingly, the ISO proposes to establish a sub-regional "license plate" rate structure for existing facility costs of the ISO and each new transmission owner sub-region. New facilities approved through the ISO's transmission planning process for the expanded region would be allocated based on benefits to each sub-region. In addition, the role of a Western States Committee in determining cost allocation for new transmission facilities will be considered through the regional governance development process.

5.7 Regional Resource Adequacy (D)

This initiative is evaluating resource adequacy policy provisions appropriate for use in a regional ISO balancing authority area that encompasses multiple states. This initiative's goal is to modify resource adequacy provisions to extend a forward planning and procurement process that ensures sufficient resources are available to the multi-state ISO to serve load under stressed and unstressed conditions, using a framework that is consistent with the resource adequacy rules that are currently in place in the multi-state ISO balancing authority area. The rules should allow for regional differences, but ensure that individual load serving entities meet their respective requirements without "leaning" on other load serving entities.

5.8 Regional Integration California Greenhouse Gas Compliance (I, D)

This initiative is determining how to track and model costs of generation to comply with state greenhouse gas regulations, if the ISO balancing authority area and market expands over multiple states. This initiative will likely leverage the ISO's current Energy Imbalance Market design that compensates resources located outside of California for greenhouse gas

I – In progress; F – FERC-mandated; N – Non-discretionary; D – Discretionary;
E1 – EIM GB Primary; E2 – EIM GB Advisory; E3 – EIM GB Hybrid Primary; E4 – EIM GB Hybrid Advisory

compliance costs for energy imported into California while not affecting the locational energy prices at the resources' location.

5.9 Metering Rules Enhancements (I, D, E2)

This initiative is developing and proposing metering rules enhancements to the process and procedures to obtain meter data used for the settlement of California ISO markets. These enhancements will provide additional metering flexibility and reduce costs to participate in ISO markets.

5.10 Storage and Aggregated DER - Phase 2 (I, D, E2)

The central focus of the ISO's energy storage and distributed energy resources ("ESDER") initiative is to lower barriers and enhance the ability of transmission grid-connected energy storage and the many examples of distribution-connected resources to participate in the ISO market. The ESDER initiative is an omnibus effort that is developing enhancements in several related but distinct topic areas. For the second phase of ESDER (i.e., ESDER Phase 2) these topic areas include non-generator resources, demand response, multiple-use applications, and station power for storage resources.

5.11 Stepped Constraint Parameters (I, F, E3)

This initiative is considering changes to the way the ISO's market handles constraints when the market must relax them to reach a solution. These constraints include transmission, power balance, and the constraints on energy transfers between balancing areas participating in the Energy Imbalance Market. This initiative is exploring whether the current penalty prices the market uses to administratively set prices when it has to relax constraints provide appropriate price signals. It is also considering alternatives to the current market rules that freeze energy transfers if a balancing area in the Energy Imbalance Market fails an hourly resource sufficiency evaluation.

5.12 Generator Contingency Modeling/Remedial Action Scheme Modeling (I, N, E2)

This initiative is exploring enhancements to ensure the market solution will not result in the system violating transmission limits after the loss of generation. The current market model only considers the loss of transmission elements. These enhancements would also enable the market to more accurately model and price resources that are part of remedial action schemes.

5.13 Commitment Cost and DEB Enhancements (I, D, E2)

This initiative is evaluating changes to the market rules for bidding commitment costs and calculating commitment cost and energy bid reference levels. This initiative will also address whether to continue the current commitment cost bid caps used by the ISO or allow additional bidding flexibility. In concert with additional bidding flexibility, this initiative will develop a market power mitigation methodology for commitment costs.

5.14 Frequency Response Phase 2 (F)

This initiative will evaluate the need and merits of a market product for resources to provide frequency response capability. The ISO will explore whether a separate payment for frequency response capability is appropriate, and, if so, it will develop the details of the payment structure.

5.15 Full Network Model Enhancements – Phase 2 (N)

This initiative will explore modeling imports and exports at their actual source and sink to improve the ISO market's modeling of actual electrical flow. The ISO may consider the potential use of "scheduling hubs" as representations of sources and sinks, e-tagging or settlement rule refinements, and remapping congestion revenue rights to scheduling hubs.

5.16 Regional Transitional Implementation Items (N)

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.

5.17 Economic and Maintenance Outages (D)

This initiative will consider whether the ISO should allow for economic outages and what form of compensation, if any, the ISO should provide if it denies a generator's maintenance or economic outage. It will explore how economic outages would interact with other requirements of the tariff and with grid and market operations.

5.18 Review Grid Management Charge Billing Determinant (D)

This initiative will explore the need to provide a transition mechanism for new participating transmission owners (PTO) that may join the ISO. Specifically, the ISO develop guiding principles that enable new entrants into the ISO balancing authority area, ensure exists PTOs are not made worse off due to the transitional mechanisms, and that outline a process by which the new PTO would transition to comparable treatment with existing PTO's.

6 Discretionary Initiatives

The following sections describe the policy initiatives identified either by the ISO or stakeholders that the ISO is not planning to start work on in 2016 or 2017.

7 General Market Design Enhancements

General market design enhancements are changes that both impact the day-ahead and real-time markets and include such items as prices formation, outage management, and resource modeling.

7.1 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 separately calculates 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. 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.

I – In progress; F – FERC-mandated; N – Non-discretionary; D – Discretionary;
E1 – EIM GB Primary; E2 – EIM GB Advisory; E3 – EIM GB Hybrid Primary; E4 – EIM GB Hybrid Advisory

7.2 Extended Pricing Mechanisms (D)

This initiative would 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)." 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.

7.3 Integrated Optimal Outage Coordination – Phase 2 (D)

This initiative would examine including economic criteria for approving or rejecting planned outage repair requests. 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.

7.4 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 ISO Controlled Grid." Section 9.3.7.3 describes what compensation will be paid to a participating transmission owner 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.

7.5 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.

7.6 Aggregated Pumps and Pumped Storage (D)

This initiative includes enhancements to participating load (PL) that would improve PL's ability to participate more fully in the market. Since the implementation of MRTU in 2009, PL's functionality has been limited to providing in the non-spinning reserves. SWP recommends that the ISO conduct a study on what improvements could be made to PL functionality that would provide system benefits and conforms to pumping load/pumping storage limitations. For instance, SWP believes that the ability for PL to bid demand in the real-time market would greatly reduce the current barriers to PL's participation in wholesale DR and possibly improve system reliability during over-generation periods. Also, by allowing PL to change its demand bid in the real-time market, PL could potentially better respond to ramping needs by shifting demand during critical ramping periods when water conditions permit.

8 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.

8.1 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.

8.2 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 look 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 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.

9 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.[9]

9.1 Real-Time Market Enhancements (D)

This initiative will examine market design changes needed to enable the five-minute real time dispatch to perform many of the functions that are now performed by the 15-minute real time unit commitment. These functions may include real-time unit commitment, ancillary services procurement, and local market power mitigation. The 15-minute market would continue to schedule interties and internal resources at 15-minute granularity but would run with a shorter lead time. Along with these changes, the ISO may consider extending the horizon of short-term unit commitment process to allow for 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.

9.2 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.

9.3 Inter-Scheduling Coordinator Trade Adjustment Symmetry (D)

This initiative was proposed by NRG. Currently, market participants engage in an Inter-Scheduling Coordinator Trade based on a forecast for a variable energy resource (VER). The ISO then updates the VER forecast, if the forecast is lower than the amount in the IST, the IST is reduced and the SC for the VER is "forced" into a Converted Physical Trade (CPT) for the difference between the previous IST and the new IST. However, if the later ISO VER forecast is higher than the amount in the IST, the IST is not adjusted. This creates asymmetrical treatment in two ways: (1) by forcing the VER SC into a CPT only where the forecast is lower but never forcing the SC for the VER buyer into a CPT where the forecast is higher, and (2) creating a mechanism in which the amount of the IST can only be reduced, but never increased, by a more accurate forecast. If the ISO VER forecast is unbiased, the IST should be allowed to go up – creating a CPT for the SC buyer – when the T-45 forecast is higher than the IST.

9.4 Exceptional Dispatch Decremental Settlement (N)

This initiative addresses settlement rules for decremental exceptional dispatch energy and shut-down energy (energy from minimum load to shutdown). 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

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

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.

9.5 Exceptional Dispatch Mitigation

This initiative would evaluate whether it is appropriate to mitigate the settlement price for exceptional dispatches the ISO makes for natural gas system reliability purposes. The ISO DMM highlighted this issue in light of the unavailability of the Aliso Canyon natural gas storage facility in Southern California and believes these dispatches may be under uncompetitive conditions. This initiative would consider mitigation for both incremental and decremental exceptional dispatches. The ISO would potentially apply any mitigation approach developed for decremental exceptional dispatches to decremental exceptional dispatches made for other reasons besides natural gas system reliability purposes.

10 Energy Imbalance Market

The energy imbalance market (EIM) extends the real-time market to other balancing authority areas in the West. The ISO's market minimizes overall dispatch costs across the combined footprint of all EIM entity balancing authority areas and the ISO balancing authority area. The EIM improves reliability by increasing the operational awareness and responsiveness to changing grid conditions across its large footprint. Further, the EIM allows for more efficient integration of renewable resources by capturing the diversity benefits across a geographical dispersed footprint.

10.1 Enhancing Participation of External Resources (D, E1)

This initiative will investigate potential EIM enhancements to allow participation of resources in balancing authority areas have not joined the energy imbalance market. The proposed changes will ensure that external participation is complementary and compatible with bilateral trades. In addition, the external resources will need to meet similar requirements of EIM participating resources. Such as locational bidding of a physical resource, modeling of resource characteristics, telemetry, and metering to enable accurate modeling of physical flows, congestion management, and ensure feasible dispatches. Also, these external resources will need to be subject to market power mitigation procedures and make transmission available to exclusively accommodate its maximum bid range. Lastly, rules will need to be developed to address potential leaning by extending the resource sufficiency evaluation to external participation.

10.2 Potential EIM-wide Transmission Rate (D, E1)

This initiative will examine four alternative potential transmission service rates, for compensation for transmission use of EIM, along with principles for comparison of alternatives. This may also address a more narrow issue of compensation for wheels between balancing authority areas and the EIM footprint.

10.3 Flow Entitlements for Base / Day-ahead Schedules (D, E1)

This initiative will evaluate adding this functionality if there is a material impact on the constraints within a balancing authority area in the EIM footprint from other EIM balancing authority areas or the ISO. Currently, the real-time congestion offset is allocated based solely upon where the constraint is located. This design change would allocate a portion of a balancing authority area's real-time congestion offset to other balancing authority areas in the EIM in the event that base schedule flows exceed agreed to flow entitlement.

10.4 Compensation for Third Parties Making Capacity Available for EIM Transfers (D, E1)

This initiative will analyze if the EIM transfer cost approach could be expanded to allow third party transmission owners to make available incremental transmission to support transfers. The incremental transmission would increase the transfer capability between balancing authority areas in the EIM footprint.

10.5 Donation by Third Party for Transmission Capacity Available for EIM Transfers (D, E1)

This initiative will analyze if the congestion rents division among EIM entities can be extended to allow third parties to receive congestion revenue on transmission made available to support EIM transfers.

10.6 Bidding Rules on External EIM Interties (D, E1)

Currently, the EIM design allows full discretion to the EIM entity as to whether real-time economic bidding is allowed on intertie scheduling points with balancing authority areas outside the EIM footprint. This initiative will determine the calculation of a default energy bid for intertie transactions, discuss liquidity issues observed on ISO interties and determine if PacifiCorp integration activities to complete the full network model implementation are required. This maybe deprioritized in support of external resource participation above. This will be the subject of a FERC technical conference in October 2016.

10.7 Changes to EIM Greenhouse Gas Design to Address Secondary Dispatch Leakage (D, E1)

California Air Resources Board (ARB) is concerned that the attribution of GHG awards to EIM participating resources does not fully account for what the atmosphere feels. ARB is currently updating its regulation to address their concerns. Based upon changes to ARB regulations modifications may be needed to the current design for attributing GHG.

11 Market Products

The ISO continues to evaluate additional market products necessary to efficiently and reliably integrate variable energy resources. Currently, 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[10] of market operations business practice manual describes these ancillary services. In addition, the ISO will be replacing the flexible ramping constraint with the flexible ramping product in fall 2016. Also, the ISO continues stakeholder to

[10] https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations

additional market products frequency response, contingency modeling enhancements, and generator modeling enhancements.

11.1 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 cost.

11.2 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.

11.3 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 move a resource up or down, respectively, in real-time within a defined capacity range using automatic generator control. The resulting imbalance energy 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 move 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.

11.4 Multi-Segment Ancillary Services Bidding (D)

PG&E has requested that this initiative be added. As explained by the ISO in its March 2012 report to FERC, “. . . multi-segment bidding for ancillary services allows scheduling coordinators to bid different quantities of an ancillary service from a resource with corresponding prices, which vary with differing levels of the resource’s output. This feature would allow scheduling coordinators to submit bids that reflect variable costs to provide ancillary services from different operating levels of a resource. This feature could also potentially lead to more efficient awards of ancillary services by allowing the ISO to consider the costs of reserving capacity at different operating levels.”

11.5 Multi-Stage Generator Regulation Refinements (D)

This initiative was added to the catalog by the ISO in September 2015. When there is low hydro availability, ISO operations is more dependent 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.

11.6 Flexible Ramping Product Enhancements (D)

The Department of Market Monitoring requests that the ISO support a stakeholder initiative that continues to enhance the design of the flexible ramping product. The flexible ramping product design that was approved in February 2016, procures and prices the appropriate amount of ramping capability to account for the uncertainty in only five minute net load forecasts. There is increasingly greater uncertainty in the net load forecasts for intervals 15 minutes, 30 minutes, and 60 minutes out from a given real-time dispatch interval. The ISO could better facilitate the integration of DERs and VERs and significantly increase the efficiency of its dispatch and pricing signals by designing a flexible ramping product that can procure and price the appropriate amount of ramping capability to account for the uncertainty in net load forecasts over time horizons longer than 5 minutes. Other flexible ramping product design enhancements that could be considered in this initiative include day-ahead procurement of flexible ramping capability, locational procurement and pricing of flexible ramping capability, and appropriately including the impacts of dispatchable-resource uninstructed deviations into the flexible ramping product demand curve and cost allocation.

12 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.

12.1 CRR Market versus Auction (D)

As discussed in the Department of Market Monitoring's (DMM's) 2015 Annual Report, since 2012 congestion revenue rights auction revenues that are allocated to load serving entities were on average $130 million less than the congestion payments received by entities purchasing these congestion revenue rights. Most of these congestion payments are paid to financial entities that purchase congestion revenue rights but are not engaged in serving any load or managing any generation in the ISO market. DMM has recommend this trend warrants reassessing the component of standard electricity market design under which ISOs auction off excess transmission capacity remaining after allocating congestion revenue rights to load serving entities.

DMM's Q1 2016 quarterly report outlines a potential approach for addressing this issue by modifying the congestion rights *auction* into a *market* for congestion revenue rights based on bids submitted by entities willing to buy or sell congestion revenue rights. DMM believes that with this approach, generators could still seek to purchase hedges for locational price differences. Financial entities or other participants could participate and submit bids reflecting a willingness to sell a hedge for locational price differences to other auction participants. Bids to buy congestion revenue rights would only be cleared if there were sufficient bids from entities willing to sell transmission revenue rights (i.e. to assume the obligation to pay congestion charges to entities purchasing these rights). This proposed initiative may make other CRR changes/enhancements unnecessary since the ISO would no longer auction off CRRs.

12.2 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.

12.3 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. This initiative may be able to leverage enhancements to outage management outlined in Section 7.4.

12.4 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.

12.5 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.

12.6 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.

12.7 CRR Allocation (D)

CDWR requests that ISO introduce an initiative to revise the Counter-flow CRR 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.

12.8 Improved Requirements for Transmission Outage Submission (D)

This initiative was proposed by DC Energy. According to the Outage Management Business Practice Manual, "requests for planned outages of Significant Facilities must be submitted to ISO Outage Coordination at least 30 days prior to the start of the calendar month for which the outage is planned to begin". The "30-day rule" is intended to improve the fidelity of the Monthly CRR network models, however the current construct does not include an incentive mechanism for adhering to the rule. That is, the rule is advisory only and there is no implication for schedules submitted inconsistent with the rule's timeline. That being said, adhering to the rule has numerous important benefits since outages on Significant Facilities significantly impact the amount of CRR network capacity offered and the resultant CRR revenue adequacy. In addition, it promotes the transparency of high impact outages, which can help rationalize CRR clearing prices and foster CRR price convergence. In order to fully realize these benefits DC Energy believes that meaningful incentives need to be put in place and we propose that a dedicated stakeholder initiative for developing an incentive based 30-day rule is carried forward.

12.9 CRR Revenue Inadequacy (D)

PG&E requests that this initiative be added. PG&E is concerned by the large sums of CRR revenue inadequacy that have occurred in the past. Revenue inadequacy totaled $200 million in 2014 and approximately $80 million through Q3 of 2015. These figures are roughly two orders of magnitude greater than what PG&E might consider acceptable. While the ISO has clearly recognized this problem and is making progress, the magnitude of the revenue inadequacy is still significant and is being borne by load-serving entities. The ISO's Department of Market Monitoring (DMM) recognized the problem and in October 2014 proposed a design solution. PG&E supports the DMM's solution and recommends that the ISO move forward with a stakeholder initiative as soon as possible.

13 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.

13.1 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.

13.2 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.

13.3 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.

14 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.

14.1 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.

14.2 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.

14.3 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.

14.4 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.

15 Infrastructure and Planning

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

15.1 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.

15.2 Interconnection Assessment of Storage Chargeability (D)

PG&E requested that this initiative be added to the catalog. PG&E is concerned that the current interconnection study process does not provide sufficient clarity as to the potential restrictions on chargeability. The lack of clarity on the chargeability of the energy storage project presents a significant commercial challenge to PG&E's storage procurement activities. Without the ability to assure some level of chargeability for projects, the buyer/off-taker and its customers carry all the risk that procured storage projects will face charging constraints that reduce the economic value of the procured project. With the mandated storage procurement targets for the IOUs, the ISO needs to enable some way for buyers/off-takers to mitigate the risk of projects not being able to charge. Accordingly, PG&E recommends that the ISO launch an initiative to examine how the interconnection process could be modified to mitigate chargeability risks and seek resolution of these topics prior to the 2016 Energy Storage RFO.

16 Proposed Deletions

This section includes the ISO's proposed deletions to the catalog. Stakeholders are requested to submit comments agreeing with deletions or an explanation as to why the initiative(s) should remain in the catalog.

16.1 Simplified Reporting of Forced Outages (D)

Reason for deletion: This initiative was subsumed in the Reliability Services Phase 1[11].

Previous Description:
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.

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

Reason for deletion: This initiative was subsumed in Bid Cost Recovery Enhancements (F, E2) that addresses two 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.

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, rather it 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 evaluates 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 submit a tariff filing by April 30, 2017.

Previous Description:
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

[11] http://www.caiso.com/Documents/Final_2016StakeholderInitiativesCatalog_Roadmap.pdf

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.

16.3 Multiple Resource IDs per Generation Meter (D)

Reason for deletion: The ISO reviewed this topic through the Metering and Telemetry Initiative. Operations then determined it would not be needed under the new Metering Rules Enhancements (I, D, E2) initiative.

Previous Description

Many renewable resources have multiple off-takers and the ISO's current system limitation of a single Resource ID per meter reportedly hampers participant's ability to submit economic bids. The ISO 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.

16.4 Price Correction Improvement

Reason for deletion: This is a process improvement. Items such as these are not included in the catalog since they do not require a stakeholder process as described in the Introduction.

Previous Description

This initiative was requested by XO Energy. This initiative is intended to reduce the frequency and magnitude of price corrections in the ISO market. Price corrections occur frequently in all the ISO markets (DA, RT, and FMM). There are three components to price corrections that are detrimental to market participants: Number of intervals corrected, Magnitude (change in price for each correction), and Delay (length of time to identify corrections to the market). The current ISO tariff allows price corrections to be made three business days after the posting of DA market results and 5 business days after the posting of RT market results. There is also the caveat that price corrections can take up to 20 days if a business process issue prevents the posting of the data within the normal timeline. The effects of price corrections are extremely detrimental to the market. All too often, market participants see a pricing signal one day and make business decisions for the next day or multiple days only to find out the original pricing signal was incorrect.

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

Reason for deletion: This initiative would be subsumed in Combine IFM/RUC with Multi-Day Unit Commitment (D).

Previous Description

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. Under a combined IFM/RUC initiative, this initiative is not needed.

16.6 Multi-Year RA Import Allocation Process (D)

Reason for deletion: The California Public Utility Commission (CPUC) opened the Joint Reliability Plan proceeding to consider multi-year resource adequacy procurement. In order to facilitate multi-year resource adequacy procurement, the ISO needed to consider allocating maximum import capability multiple years into the future so that load serving entities could fulfill resource adequacy obligations with combinations of internal and external resources. The CPUC has closed the Joint Reliability Plan proceeding, thus deferring multi-year resource adequacy procurement for the foreseeable future. As such, the multi-year maximum import capability allocations are not needed at this time. The ISO will revisit this matter if the CPUC reopens a proceeding to consider multi-year maximum import capability allocations.

Previous Description

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.

16.7 Outage Notification Requirements (D)

Reason for deletion: This initiative was subsumed in Operational Transparency Customer Partnership Group[12].

Previous Description

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.

[12] http://www.caiso.com/informed/Pages/MeetingsEvents/CustomerPartnershipGroups/Default.aspx