2015 Stakeholder Initiatives Catalog,
Discretionary Initiatives High Level Ranking

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CPUC staff appreciates this opportunity to comment on the annual effort to prioritize the CAISO stakeholder initiatives and provide feedback to the CAISO on improving market efficiency to reduce costs to ratepayers.

Summary:

This year as in past years, CPUC staff believes that initiative 7.4 Convergence Bidding Uplift Allocation should be one of the top ranked initiatives. Uplifts remain one of the key signals of market inefficiency and should be one of the key drivers in for undertaking market design changes.

After our review of the CAISO ranking of stakeholder initiatives catalog CPUC staff agrees with the high ranking of the following items:

3.4 – Extend Look Ahead for Real-Time Optimization;

2.3 - Multi-Day Unit Commitment in Integrated Forward Market;

11.14 Multiple Resource IDs Per Generation Meter; and

3.2 - Default Load Aggregation Point Level Proxy Demand Response.

Regarding 3.11 - Generator Contingency Modeling, CPUC staff disagrees with the high ranking of this initiative because it is difficult to justify the improvement to overall market reliability and efficiency. Staff also agrees with others that it should be listed as discretionary and that it should not be included as high in the ranking.

The following initiatives should be moved up in the ranking, and to the extent possible these should be combined, because they are related to each other and combining them would be more effective.

10.8 Maximum Import Capability;

- 10.8.1 Comprehensive Review of Methodology for determining Maximum Import Capability;
- 10.8.2 Reallocation of Maximum Import Capability between Electrically Adjacent Import Paths to achieve State Policy Objectives; and
- 10.8.3 Allocation of Maximum Import Capability among Load Serving Entities .

In addition, CPUC staff believes the CAISO should move the Congestion Revenue Right (CRR) initiative 6.1 (D) to a higher ranking. A stakeholder initiative is necessary to discuss remedies to minimize or eliminate CRR revenue inadequacy.

Detailed Comments {The blue font represents extracts from the CAISO's draft Stakeholder Catalog**}:**

Initiative 7.4 - Review of Convergence Bidding Uplift Allocation should be ranked highest.

This initiative would explore allocating the uplift to physical and virtual schedules in proportion to the quantity of out-of-market congestion payments received by physical and virtual schedules. SCE notes that in its May 9, 2013 order on lowering the transmission relaxation parameter, the FERC wrote "The Commission encourages CAISO to pursue its evaluation [of proper uplift allocation] vigorously and to propose solutions to the observed difficulties promptly when they become evident."19 Under current tariff provisions, all uplifts associated with convergence bidding are allocated to demand. This initiative would be to conduct a comprehensive evaluation of the costs and benefits associated with convergence bidding and to implement a method or methods for allocating the costs of convergence bidding to the entities that benefit from convergence bidding.

Like last year, we ranked this initiative as one of the most important initiatives. Under current tariff provisions, all uplifts associated with convergence bidding are allocated to Measured Demand. This initiative would conduct a comprehensive evaluation of the costs and benefits associated with convergence bidding and implement a method or methods for allocating the costs of convergence bidding to the entities that benefit from convergence bidding. Alternatively, this topic could be included in a more comprehensive review of ISO cost allocation methods to consider whether all cost allocation methods comport with the cost causation principle. We think review of convergence bidding uplift allocation should be ranked highest.

Grid Reliability

This initiative should improve grid reliability to the extent that it aligns market participants' behavior, which affects congestion and reliability, with cost consequences.

Improving Overall Market Efficiency

The virtual bidding uplift allocation should be considered within a stakeholder process to reduce the potential for increased virtual bidding uplift on interties when virtual bidding is reinstituted in the market.

Virtual bids are poorly suited to solve congestion problems. For example, when unanticipated loop flows come across CAISO's transmission lines, the virtual bids could cause revenue shortfalls because the ISO must necessarily pay a higher price to deliver energy to a congestion constrained area. As a result, the virtual bidders will receive the same higher price from the CAISO, yet they have no stake in anticipating the congestion uplift in the Real-Time market or mitigating the price differential.

Furthermore, virtual bidders can gain higher prices and profits by using so-called "offsetting bids"[1] to actually *cause* congestion and profit from the congestion they caused. This results in undue congestion uplifts that are charged to ratepayers and these higher profits go to the virtual bidder. The Department of Market Monitoring found in 2012 that nearly all of the $56 million net profits paid to virtual bidders were due to congestion uplift costs gained by using "offsetting bids" in this manner.

Therefore, it is important to take up this initiative to align cost allocation with cost causation. There should be minimal cost for market participant implementation. Addressing convergence bidding uplift allocation will not impinge the ability for participants to take advantage of the legitimate benefits of virtual bidding (e.g., hedging risk of high or low prices).

<u>Initiative 3.4 – Extend Look Ahead for Real-Time Optimization should be ranked highly because it has the potential to improve market efficiency and effectiveness.</u>

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

This initiative has the potential to increases grid reliability and market efficiency by creating the potential to commit longer start units during the day. When more renewables are available to the Real-Time Market to address intra-day changes supply and demand market efficiency should be improved. The impact on market participants should be minimal, with the greatest impact on the CAISO to change their processes to forecast and commit over a longer horizon intra-day.

[1] An "offsetting bid" is where the virtual bidder places a demand bid at a node with high demand, and then a supply bid on the other side of a line where congestion is expected (knowing that loop flows from other BAAs could show up and violate the transmission constraint, forcing CAISO to change its model in Real-Time to accommodate the unscheduled flows).

Initiative 2.3 - Multi-Day Unit Commitment in Integrated Forward Market (IFM) should be ranked highly and has the potential to improve market efficiency and reliability.

CPUC staff ranked this initiative high in the past and continues to support a high ranking this year.

Currently, the forward looking time horizon in the Integrated Forward Market (IFM) is one day, which also takes into account the impact of prior commitment of units with very long start up times. During the MRTU process, some stakeholders requested that the ISO make two-to-three day commitment decisions in the IFM to create more efficient results and better reflect the impact of startup-up cost for resources that have long start-up times. There are several design issues, including the need for bidding and bid replication rules as well as software performance and solution time requirements, which should be discussed and resolved via a stakeholder process before considering modification of the software to accommodate multi-day unit commitment in IFM.

As the ISO completed its design for the new market, the ISO found that there is an opportunity to run an optimization process, "Extremely Long-Start Commitment" (ELC), following the RUC process. The RUC process considers unit commitment to meet the ISO's forecasted demand for generators with up to 18-hour start-up times. However, there are a small number of generators with start-up times exceeding 18 hours. The ELC process provides the ISO with the opportunity to determine when it should commit these generators for reliability purposes by using a 48-hour optimization period.

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

The justifications for this interim step initiative are similar to those for the above Integrated Forward Market imitative. With the capability to anticipate the need for and economically commit long start units the increased supply stack would facilitate holding fast start resources back to be available for ramping needs by serving some load with longer start resources. Flexible resources are a significant concern for reliability, and they may become increasingly important in the future.

The Department of Market Monitoring found that in 2012, one percent of all intervals experienced a price spike driven by insufficient ramping capability. For the reasons stated above, this initiative could increase available flexible resources and mitigate flexibility-driven price spikes with economic dispatch of flexible resources, thereby increasing market efficiency.

Initiative 11.14 - Multiple Resource Identifications (IDs) Per Generation Meter should be ranked highly because it is consistent with state policy goals with the potential to improve market efficiency.

Many renewable resources have multiple “off-takers” (i.e. multiple Purchased Power Agreements exist for a single resource). The CAISO’s current system limitation of a single Resource Identification (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. This capability exists in the MISO, PJM, and the ERCOT and dispatchable wind in these markets has provided significant benefit in the form of cost-effective and reliable dispatch.

This initiative will facilitate better scheduling and potentially increase economic bidding of renewable resources by allowing renewable resources with multiple off-takers to each schedule their portion of the resource. The result could increase liquidity of renewable resources and result in a more efficient dispatch. This initiative should not require a large amount of market participant resources to implement. The effort and impact appears to fall largely on the CAISO.

Initiative 3.2 - Default Load Aggregation Point (DLAP) Level Proxy Demand Response (PDR) should be ranked highly and increases potential market reliability and efficiency.

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

The United States Court of Appeals’ in Washington DC vacated ruling of FERC Order 745 is being challenged by multiple parties and will not be resolved in the near future. Until these challenges are resolved, CAISO should proceed with its ongoing PDR efforts. The DLAP level pricing of PDRs recognizes that certain kinds of Demand Response (DR) may not necessarily fit into more granular dispatch, and thus, it makes sense to explore what can be done for those resources that respond at the DLAP level.

This initiative would revise PDR rules to better accommodate DR resources which cannot integrate into CAISO’s markets under current rules, and it creates a potential pathway for flexible DR to participate. CPUC staff support such efforts as they are consistent with the objectives of the CPUC Demand Response rulemaking, which is to make DR more useful for the grid’s needs. It is anticipated that by facilitating more DR resources to participate in the market the increased liquidity and competition will drive overall market efficiency.

The IOUs and third-party demand response providers may need to expend the most effort to organize and implement PDR. The impact on the CAISO’s resources is difficult to determine given that there already are DLAP pricing structures in place for load.

Initiative 10.8 - Maximum Import Capability (including 10.8.1, 10.8.2 and 10.8.3) should be combined and ranked highly because of their similarity and potential increase in market efficiency and congruence with state policy goals.

As set out in the ISO tariff, the ISO is responsible to determine the maximum import capability for each import path into the ISO balancing authority area, so that imports can be included in the state's resource adequacy program. Key attributes of the methodology include the fair and reasonable consideration of imports, and the need for simultaneity among the resources included in resource adequacy capacity assessments.

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

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

CPUC staff has previously supported CAISO opening an initiative/process on the Maximum Import Capability (MIC) methodology. A major objective would be to accommodate procurement of desirable external resources in a more proactive, planned manner, as opposed to having MIC be dependent on the amounts of historical (prior 2 years) actual imports. The associated MIC initiatives should have a relatively high priority based on the potential impacts on grid reliability and resource adequacy capacity.

However, there should be an initial assessment or taking-stock of where things stand regarding need for more proactive MIC. The following needs to be considered:

- How many MW of external resources are in the queue requesting full deliverability?

- Where are the resources in the procurement process?
- Whether RPS already in portfolios would be precluded from RA deliverability due to insufficient MIC over particular interties. And what is the magnitude of those precluded from deliverability?
- What interties are affected and to what extent?

Accommodating procurement of desirable external resources in a more proactive, planned manner, as opposed to having MIC dependent on amounts of historical (past 2 years) actual imports, should increase deliverable capacity. Accommodating procurement in a more proactive and planned manner will help in enhancing renewable delivery options to align with state policy goals and should more effectively utilize import capacity. Taking this on sooner is important because historically establishing any new resource adequacy methodology in the state resource adequacy program involves a comprehensive review and a major commitment of policy and technical staff.

- 10.8.1 Comprehensive Review of Methodology for determining Maximum Import Capability;

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

  Stakeholders in the transmission planning process 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 would also potentially an enhancement to the MIC approach for delivery when delivery may not need to occur simultaneous with bulk energy delivery (e.g., when delivery is needed only when renewables ramp down and not simultaneous with full output renewable delivery).

- 10.8.2 Reallocation of Maximum Import Capability between Electrically Adjacent Import Paths to achieve State Policy Objectives;

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

- 10.8.3 Allocation of Maximum Import Capability among Load Serving Entities should be ranked higher.

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

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

Initiative 6.1 - Congestion Revenue Rights Enhancements to address Revenue Inadequacy should be highly ranked because of the potential to address market design deficiencies, market efficiency and reduction in overall cost to ratepayers.

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

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

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

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

4. Consider allocating the real-time congestion offset to congestion revenue rights. Currently the ISO allocates the real-time congestion offset to measured demand. Other

> ISOs allocate this cost through their congestion revenue right balancing account. This would require the risk of the real-time congestion offset allocation to be priced in the congestion revenue right auction.

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

This initiative should be ranked highly and undertaken in 2015 because the Congestion Revenue Rights (CRRs) are designed to be revenue neutral and because the CAISO notes there is significant revenue inadequacy which signals significant market inefficiencies. These problems could originate from faulty market design; processes and/or execution; or be evidence of the exercise of market power. The revenue inadequacy is sufficiently large that it raises questions over the impacts on market efficiency as well as whether there are perverse incentives for market participants to take advantage of the market weakness.

As noted above there are many potential enhancements and modifications that could increase CRR market efficiency and provide proper incentives that focus on minimizing congestion rather than incentivizing increase congestion for profit. We see that there are nine initiatives in the catalog directly related to CRRs. There are good reasons to address CRRs sooner rather than later, especially to eliminate the revenue inadequacy and improve market efficiency. This initiative should be highly ranked because the cost to fix these problems would be significantly less than the resources needed to address these issues.

Deleted Initiatives:

Initiative 13.6 - Mitigating Transient Price Spikes, Real-Time Imbalance Energy Offset/Real-Time Congestion Offset this initiative should be reinstated to the Stakeholder Catalog because this remains a significant market issue with market equity and efficieny impacts.

CPUC staff remains concerned that even though the CAISO has initiated several efforts[2] to address issues that might benefit Real-Time Imbalance Energy Offset (RTIEO) and/or Real-Time Congestion Offset (RTCO) the intended benefits have yet to be fully realized. The CAISO reported that the RTIEO is composed largely of unscheduled flows and loss returns during the

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[2] 1) Lowering the transmission constraint relaxation parameter used in the scheduling run of the real-time dispatch from $5,000/MWh parameter to $1,500/MWh. 2) The 15 minute real-time market, implemented as part of the FERC Order 764 market initiative, should address uplift resulting from price differences between the hour-ahead scheduling process and real-time dispatch. 3) The flexible ramping product initiative should reduce real-time price spikes due to a shortage in ramping capability. 4) The full network model expansion initiative is supposed to make modeling improvements in the day-ahead market that is supposed to improve convergence between day-ahead and real-time modeled conditions.

November Market Planning Meeting[3]. It is not clear what the impact from changes made to market rules categorizing uninstructed imbalance energy could be having on RTIEO because a netting effect may distort the level of RTIEO. Therefore, we think this initiative should remain in the catalog to be revisited. A stakeholder initiative should be undertaken if after both the RTIEO and RTCO are not significantly reduced in the first half of 2015 from the 2014 market releases.

[3] http://www.caiso.com/Documents/Agenda-Presentation_MarketPerformance-PlanningForum_Nov18_2014.pdf; Slide 22.