May 22, 2014

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER14-____-000

Tariff Amendment to Implement Modeling Enhancements

Dear Secretary Bose:

The California Independent System Operator Corporation submits the attached revisions to its Fifth Replacement FERC Electric Tariff.

Respectfully submitted,

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Tariff Amendment to Implement Modeling Enhancements

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") submits revisions to its tariff necessary to implement modeling enhancements in the ISO markets.[1]

The ISO respectfully requests that the Commission issue an order by July 31, 2014, that (1) accepts the proposed revisions to tariff sections 11.2, 27.5.1.1, 30.5.2.1, and 30.5.2.4, and the new defined term "Transaction ID," to reflect improvements in the ISO's base market model and use of transaction identifiers effective September 8, 2014, and (2) accepts the balance of the proposed tariff revisions effective October 1, 2014. Granting this request will enable the testing and implementation of the modeling enhancements to align with the schedule for implementing ISO market design enhancements, including the new energy imbalance market, in Fall 2014.

I. Executive Summary

By this tariff amendment, the ISO proposes important modeling enhancements which include the authority to model unscheduled flow in the ISO's day-ahead market, the enforcement of power flow constraints in the day-

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[1] The ISO submits this filing pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the ISO tariff, and references to specific sections are references to sections of the ISO tariff as revised by this filing unless stated otherwise.

ahead market, and the expansion of the full network model topology to include information on resources, load, and interchange schedules in other balancing authority areas. These enhancements will provide significant reliability and market efficiency benefits. The ISO's proposal is consistent with the practices of other independent system operators and regional transmission organizations and will not unduly interfere with the scheduling practices in the remainder of the Western Interconnection. The proposal also complements the expanded energy imbalance market that the ISO intends to implement this fall by improving the quality of market results.

Until now, limited data has been available to the ISO to reliably capture the impact of unscheduled flow in the day-ahead timeframe. However, as a result of recent regional coordination efforts among utilities in the West, the ISO now has access to more data regarding day-ahead system conditions (*e.g.*, resources, load, and interchange schedules) in other balancing authority areas. With the ready availability of relevant supply, load, and intertie schedule data in the Western Interconnection, the ISO proposes to begin accounting for unscheduled flows at its interties in the day-ahead market. Specifically, with the availability of additional data, the ISO will now be better able to account for unscheduled flows by enhancing its modeling activities in the following three ways:

1. Modeling in the ISO's market processes unscheduled electrical flows that occur within the ISO balancing authority area, based on available information for other balancing authority areas such as supply, demand, and net interchange information.

2. Making use of physical flow limits between the ISO and neighboring areas over certain interties so that the ISO can operate the day-ahead market in a manner that more accurately reflects actual system conditions that materialize in the real-time.

3. Enhancing the level of detail in the ISO's full network model to more accurately reflect the anticipated day-ahead and actual real-time system topology of other balancing authority areas in the Western Interconnection.

These enhancements will provide significant reliability and market benefits. In particular, they will ensure that the day-ahead market results, including both schedules and pricing, will more accurately reflect conditions anticipated in the real-time and will better align with real-time schedules and pricing.

The ISO manages congestion primarily through its security constrained economic dispatch process and by unit commitments made in its day-ahead and real-time markets. To the extent the ISO's network models and assumptions of flows do not adequately reflect the actual topology and physical flows of neighboring transmission systems, the ISO market solutions will not be based on actual conditions. Therefore, any improvements the ISO makes to its model of the integrated transmission grid will improve the ISO's market solutions. These modeling enhancements will also reduce infeasible schedules in the day-ahead market that result in expensive redispatch of resources in the real-time market, thereby reducing real-time congestion uplift costs. As part of this effort, the ISO will inform market participants of the unscheduled flow considered in the day-ahead and real-time markets. This will provide market participants with greater visibility into the ISO's modeling of system conditions and will enable market participants to participate in the ISO markets more effectively and efficiently.

Better modeling of unscheduled flow and enforcement of power flow constraints in the day-ahead market will also promote system reliability by allowing the ISO to more accurately model expected real-time conditions in the day-ahead timeframe, including unscheduled flow, outages, and contingencies.

The ISO has developed a sound, detailed methodology to use available day-ahead data to model external resources and load, as well as conditions on transmission facilities in other balancing authority areas. The instant tariff amendments provide the ISO with the necessary flexibility to model unscheduled flows in the day-ahead market. The flexibility the ISO requests is comparable to the authority the Commission has already approved for modeling unscheduled flow in the ISO's real-time market. The additional reliability and market efficiency benefits of modeling unscheduled flows in the day-ahead market support similar flexibility here. As discussed in greater detail below, the ISO's proposal includes a provision that will allow the ISO to not model unscheduled flow and enforce the power flow constraints if certain criteria are not satisfied, *e.g.*, if the data and modeling of unscheduled flow are not accurate. The ISO must have the flexibility to adjust its methodology for modeling unscheduled flow and in some instances abstain from modeling such flows in the event the available data yields unreliable results.

The full network model is a detailed network model used in the ISO's market processes. It reflects the interconnected power system of the ISO controlled grid and certain parts of the external grid. The ISO uses the full network model to create the base market model that the ISO uses in operating the ISO energy and ancillary services markets in order to ensure that market outcomes are consistent with actual flows on the transmission grid. The full network model represents external balancing authority areas and external transmission systems in order to support accurate modeling of power flows in the ISO markets. For example, the ISO models certain looped systems in the south whose operations have been transferred to the ISO, but are not in the ISO balancing authority area. However, the existing full network model and base market model lack visibility of sources and sinks in many parts of the Western

Interconnection. Access to data reflecting the topology of the extended networked system in the Western Interconnection will enable the ISO to better account for actual flows on its system as part of the greater integrated system. The ISO's proposal to reflect the sources and sinks in the external balancing authorities in the base market model will provide greater visibility regarding those flows. Thus, to the extent the ISO has sufficient data it will expand the topology in its full network model to ensure that internal and intertie schedules and prices appropriately reflect the flows on the integrated Western Interconnection.

The proposed modeling enhancements are responsive to the joint recommendations of the staffs of the Commission and the North American Electric Reliability Corporation ("NERC") following the September 8, 2011, outage event. The modeling enhancements proposed herein address the recommendation that the ISO and other balancing authority areas should better coordinate their day-ahead planning. By incorporating a more accurate representation of flows on the interconnected grid, the ISO will produce more feasible day-ahead schedules that align more closely with actual system conditions. These enhancements are instrumental towards enabling the ISO to manage congestion on the system more reliably through its markets.

Stakeholders expressed broad support for the ISO's goal of modeling enhancements, and the ISO has addressed specific concerns raised by stakeholders. Stakeholders generally support expanding the ISO topology in the full network model and the base market model. Some stakeholders do raise concerns with how the ISO will model unscheduled flows and what the impacts of its modeling will be. Therefore, in response to stakeholder requests, the ISO commits to analyzing the results of its modeling of unscheduled flow during a test period and demonstrating the effectiveness of such modeling before the ISO actually implements the modeling of unscheduled flows in the day-ahead market. The analysis the ISO will undertake will be a power flow-based modeling assessment that will apply the ISO's methodology to actual market data prior to implementation to show the difference between the current and expanded modeling. The ISO will conduct the analysis this summer once the software code to implement the enhancements is available and will file an informational report with the Commission showing the results of this analysis. If there are any concerns regarding the accuracy of the base schedules, the ISO's proposal includes a mechanism that will enable the ISO not to include unscheduled flow measurements in the day-ahead market if certain criteria are met.

Some stakeholders questioned why the ISO should address unscheduled flow from other parts of the West before the rest of the region takes steps to address unscheduled flow issues. These stakeholders ignore the fact that the ISO is the only organized market in the western United States. It is eminently reasonable for the ISO to take measures to ensure that its modeling produces feasible schedules that support both the reliable operation of the ISO controlled grid and efficient operation of the ISO markets. There is no basis for requiring the ISO to ignore the clear impacts of the interconnected nature of the Western interconnection in establishing schedules and prices on its system. As explained below, the ISO's proposal does not undermine ongoing inter-regional coordination efforts or interfere with prevailing scheduling practices in other parts of the West.

The ISO's Market Surveillance Committee has reviewed the proposed modeling enhancements and issued an opinion expressing strong support for the proposal. The Market Surveillance Committee also notes that the planned extension of the ISO network model to encompass a broad region outside the ISO controlled grid is consistent with the existing use of expanded network models by independent system operators and regional transmission organizations in the eastern United States. The Market Surveillance Committee further concluded that testing and implementation of the modeling enhancements is an essential first step on the road towards better regional integration and more accurate system modeling.

The modeling enhancements will also complement the ISO's new energy imbalance market with other balancing authority areas in the West. The enhanced model will provide improved power flow solutions for the combined ISO and energy imbalance market footprint, thereby improving the quality of market solutions and supporting the feasibility of energy imbalance market schedules. As such, it is important that the Commission approve the ISO's proposal in a timely manner so the modeling enhancements can be in place for the implementation of the energy imbalance market.

For all these reasons, the ISO respectfully requests that the Commission find that the ISO's proposal is just and reasonable.

II. Background

A. Overview of ISO Market Structure

The ISO administers both day-ahead and real-time wholesale electricity markets. One of the primary objectives of these interrelated markets is to ensure that there is sufficient supply of electricity to satisfy demand in the region while maintaining the reliability of the transmission system operated by the ISO (the ISO controlled grid). These markets simultaneously optimize the procurement of energy and ancillary services and allocate the use of transmission capacity on the ISO controlled grid based on locational marginal pricing at both internal nodes (*i.e.*, locations within the ISO balancing authority area) and the interties (*i.e.*, locations for imports to and exports from the ISO balancing authority area).

The day-ahead market includes a market power mitigation process that mitigates submitted bids when there is an indication that the potential to exercise market power exists. The integrated forward market – the next process in the day-ahead market – then considers available supply and demand bids to identify the most efficient schedule of resources to address system needs. When forecasted load is not met in the integrated forward market process, the residual unit commitment process enables the ISO to procure additional capacity to meet the forecast.

The real-time market is a spot market that uses security constrained unit commitment and security constrained economic dispatch to commit and dispatch resources to serve demand in the real-time.[2] As of May 1, 2014, the ISO's real-time market includes a fifteen minute market that produces financially binding 15-minute prices for energy and ancillary services for all internal transactions and for all transactions of market participants that choose to schedule on the interties on a 15-minute basis. To the extent that supply bid into the real-time market processes is insufficient, the ISO re-dispatches resources and performs exceptional dispatch (*i.e.*, dispatch of resources outside of the normal market processes) in order to meet real-time demand.

When transmission capacity is scarce, the ISO markets result in transmission congestion charges, which are incorporated into locational marginal prices. Market participants can acquire congestion revenue rights, which are financial instruments they can use to manage exposure to congestion charges in the day-ahead market. In addition, market participants can engage in convergence bidding to hedge their physical market positions and manage their exposure to differences between day-ahead and real-time prices.[3]

B. The Full Network Model

The full network model is a detailed, computer-based mathematical representation of the physical transmission system the ISO operates. The full network model includes all transmission network busses (*i.e.*, load and generating unit busses) and transmission constraints within the ISO balancing authority area as elements of a looped network. The full network model also includes all intertie busses between the ISO balancing authority area and other balancing authority areas that are interconnected with the ISO. The full network model represents external balancing authority areas and external transmission systems to the extent necessary to support accurate modeling of power flows in the ISO markets. For the most part, the ISO's existing full network model does

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[2] Fewer resources generally are available to be committed in the real-time compared with the day-ahead.

[3] Market participants engage in convergence bidding by submitting virtual bids.

not reflect the injections and withdrawals at sources and sinks in external balancing authority areas in the Western Interconnection, because the necessary data has not been available from other balancing authority areas. The ISO has made use of whatever data it has available to include in the full network model a partial closed loop of transmission external to the ISO's balancing authority area and controlled grid. This has enabled the ISO to improve the functioning of the markets by reflecting the impact of flows from the ISO's market schedules through the external system, in order to better represent congestion within the ISO grid itself. The ISO uses a similar network model for allocating and auctioning congestion revenue rights.

The ISO uses the full network model for security constrained unit commitment and security constrained economic dispatch, which results in more accurate schedules. Specifically, the ISO uses the full network model to create the base market model, which is a computer-based model of the ISO controlled grid. The base market model serves as the basis for formulating the individual market models used in the operation of each of the ISO markets to establish, enforce, and manage the transmission constraints associated with network facilities. The ISO's software systems currently formulate the base market model from the full network model by: (1) introducing locations for modeling intertie schedules, and (2) adding market resources that do not exist in the full network model due to their size and lack of visibility.

C. Need to Enhance the ISO's Modeling

1. Commission and NERC Staff Recommend Increased Sharing and Use of Load, Generation, Outage and Interchange Data Following the September 8, 2011, Event

On September 8, 2011, a system disturbance in Arizona and subsequent events caused cascading outages throughout Arizona, southern California, and the Baja California peninsula.[4] Staff of the Commission and NERC conducted an inquiry to consider the causes of the outages and develop recommendations to prevent such events in the future. That inquiry resulted in the staffs of the Commission and NERC issuing a joint report in April 2012 with a number of findings and recommendations based on the inquiry into the September 8, 2011, event.[5]

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[4] The outages affected the following transmission operators and balancing authorities: Arizona Public Service Company, Imperial Irrigation District, the ISO, San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("SCE"), and Western Area Power Administration – Lower Colorado in the United States, and Comisión Federal de Electricidad in Mexico. SDG&E and SCE are transmission operators only and the other listed entities are both transmission operators and balancing authorities.

[5] *Arizona-Southern California Outages on September 8, 2011 – Causes and*

Two of the recommendations in the April 2012 report relate to the proposed modeling enhancements. The first of these recommendations was made in response to the report's finding that the models for external networks used by some transmission operators in the Western Interconnection are not updated to reflect next-day operating conditions external to their systems. Specifically, the April 2012 report recommended that transmission operators and balancing authorities should:

- ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems; and

- take steps, such as executing nondisclosure agreements, to allow the free interchange of next-day operations data between operating entities.[6]

The second recommendation was made in response to the April 2012 report's finding that transmission operators in the Western Interconnection have limited real-time visibility outside their systems. In particular, the April 2012 report recommended that transmission operators should:

- engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems;

- obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the system operating limits of other transmission operators; and

- review their real-time monitoring tools to ensure that such tools represent critical facilities needed for the reliable operation of the bulk power system.[7]

As discussed below, the modeling enhancements will allow the ISO to more accurately model expected real-time conditions in the day-ahead timeframe by including unscheduled flows, outages, and contingencies, which will increase

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Recommendations (Apr. 2012) ("April 2012 report"), available on the Commission's website at http://www.ferc.gov/legal/staff-reports.asp.

[6] April 2012 report at 68.

[7] *Id.* at 86.

the reliability of the ISO controlled grid. Enhancing the level of detail in the ISO's full network model will also allow the ISO to more accurately reflect the actual real-time system topology of other balancing authority areas in the Western Interconnection. These enhancements are aligned with the recommendations in the April 2012 report.

2. Not Modeling the Full Scope of Power Flows in the Day-Ahead Market Results in Less Reliable Day-Ahead Market Solutions that Must Be Addressed Closer to Real-Time Either through Redispatch of Resources or Out-of-Market Actions

The April 2012 report highlights reliability enhancements that can be gained by updating network models to reflect next-day operating conditions in other balancing authority areas and by improving software visibility of real-time conditions outside the ISO controlled grid. For the ISO, ensuring reliability and operating efficient markets are interrelated. For example, the ISO uses the market to reliably manage congestion on its transmission system and, in turn, to account for transfers and uses of the ISO controlled grid so it can achieve a reliable and efficient market dispatch. Resources on the ISO grid are dispatched and scheduled through the ISO markets. Only in exceptional circumstances does the ISO dispatch resources outside of its market processes. Therefore, the feasibility and accuracy of the market solution is an important element of the ISO's ability to operate the system reliably.

There are anticipated real-time unscheduled flows that currently are not captured and accounted for in the ISO's day-ahead market. The ISO captures these in the real-time market, but the absence of any accounting for such flows in the day-ahead market results in infeasible schedules that need to be managed in real-time. These inefficiencies pose reliability risks and impose unnecessary costs to managing congestion on the ISO grid.

One of the factors giving rise to unscheduled flow is the use of contract path scheduling, which continues to be prevalent in the Western Interconnection. Contract path scheduling is based on the convention that electricity flows along a designated path and that schedules can be accepted up to an agreed-upon scheduling limit enforced by each balancing authority. On the other hand, physical flow-based limits reflect the realities of an interconnected transmission system where energy flows along the path of least resistance. Physical flow-based limits are often equal to, but may be different from, the enforced scheduling limit. The physical flow limit and scheduling limit are separately enforced.

The ISO enforces the physical flow limits on transmission facilities located within the ISO area in both the day-ahead and real-time. Currently, the ISO enforces scheduling limits (but not physical flow limits) on the interties in the day-ahead market, and it enforces both scheduling and physical flow limits on the interties in the real-time.[8] Until now, the ISO has enforced only the scheduling limits on the interties in the day-ahead because of a lack of sufficient information regarding supply and demand in external areas not under the ISO's control. Enforcing the physical flow limits would likely have caused inaccurate network modeling results due to the limited modeling in the full network model of transmission facilities external to the ISO and the unavailability to the ISO of external scheduling data for use in the ISO market processes.[9]

The figures and table below provide illustrative examples of the differences between enforcing the contract path versus physical flow limits. In Figure 1, the image on the left shows a 100 MW import scheduled into the ISO over intertie T1. In this example, contract path scheduling assumes that all 100 MW flows over T1.[10] However, in actuality, only 80 MW may flow over T1 while 20 MW flows over intertie T2. The 20 MW flow over T2 is the unscheduled flow. Unscheduled flow can result from ISO market transactions as well as non-ISO transactions. For example, imports and exports between other balancing authority areas may result in some unscheduled flow over the ISO system and vice versa. Not accounting for such unscheduled flow has financial and dispatch implications for the ISO system, which are detailed below.

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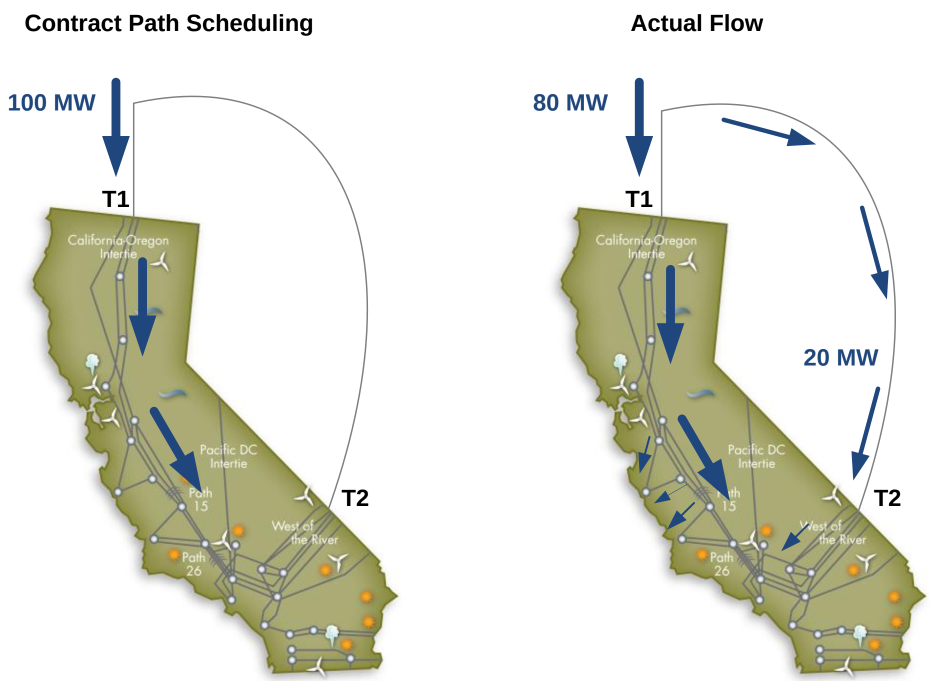
[8] Tariff section 27.5.6; business practice manual for managing full network model at 17. Each intertie has both a physical flow limit and a scheduled flow limit, the latter of which has been agreed to by the ISO and the applicable interconnected balancing authority. Business practice manual for managing full network model at 17.

[9] *Id.* at 17. However, the ISO may enforce the physical flow limits on the interties in the day-ahead in the limited circumstance where the ISO determines that congestion is likely in real-time, to the extent such congestion is a result of ISO market schedules. *Id. See also California Independent System Operator Corp.*, 126 FERC ¶ 61,262, at PP 68, 72 (2009) (declining to require the ISO to account for unscheduled flow in the day-ahead market as it does in the real-time and noting that the ISO indicated it had insufficient data to do so at that time).

[10] The illustrative example also assumes no transmission losses.

Figure 1: Differences in Contract Path and Actual Flows



Building on the previous example, assume that T1 and T2 have scheduling and physical flow limits of 100 MW and 50 MW, respectively.[11] In addition to the 100 MW scheduled over T1, assume the ISO accepts an additional import schedule over T2 of 50 MW. Under the contract path scheduling paradigm, the schedules do not violate the scheduling limits, as shown under the contract path scheduling calculations in Table 1 below in columns [B] through [D]. The calculations for the physical flow of the schedules are different and are shown in the same table below in columns [E] through [I]. While the import limits are the same (compare columns [B] and [E]), the physical flow from each schedule (column [F]) is less than the scheduled amounts (column [C]). In addition, each import schedule also produces unscheduled flow on the other intertie (column [G]). This means that the total physical flow (column [H]) can exceed the physical flow limit of each intertie (column [I]).

[11] In this illustrative example, the scheduling and physical flow limits are equal to each other for each of the interties.

Table 1: Accounting of Differences in Contract Path and Actual Flows

	Contract path scheduling			Physical flow				
Intertie	Scheduling limit – import (MW)	Import schedules (MW)	Over limit?	Physical flow limit – Import (MW)	Physical flow from schedule (MW)	Unscheduled flow (MW)	Total flow	Over limit?
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Formula			*[C] > [B]?*				*[F] + [G]*	*[H] > [E]?*
T1	100	100	No	100	80	10 (from schedule over T2)	90	No
T2	50	50	No	50	40	20 (from schedule over T1)	60	Yes

Because the ISO does not currently enforce a physical flow limit at the interties in the day-ahead timeframe, these illustrative import transactions, if economic, would be accepted into the ISO day-ahead market because they do not violate the scheduling limits. However, it is clear from a physical flow perspective that unscheduled flow will cause congestion on intertie T2. This has both financial and dispatch consequences. First, not fully reflecting the congestion on T2 means that the day-ahead market schedules are based on a locational marginal price at T2 that would likely overpay imports there.[12] Less accurate prices decrease market efficiency and the strength of pricing signals. This uniquely affects the ISO as the only organized electricity market in the western United States with a financially binding day-ahead market. The accepted practice in the Western Interconnection has been to defer management of unscheduled flow to the real-time only, which leads to the problems described here.

[12] The issue of overpayment extends beyond simply paying too much in the day-ahead market when the lack of modeling of injections and withdrawals from external sources and sinks results in failure to recognize congestion that will occur in the real-time market. The failure to recognize such congestion in the day-ahead timeframe will result in overpayments in the day-ahead market. Then, in the real-time market, the congestion will cause import schedules to be curtailed and the locational marginal price at the intertie's scheduling point to be reduced. The reduced locational marginal price in the real-time market would mean that the importer could compensate the market for the schedule reduction at a lower price than the importer earned in the day-ahead. If the original day-ahead import were backed by hydroelectric generation, the operator could keep the water in storage, and repeat this sequence at a later time. If the reduction in schedules in real-time resulted in a negative locational marginal price, the importer could end up being paid both for its day-ahead schedule and again for reducing its schedule at a negative locational marginal price, without actually delivering the energy that was curtailed.

Second, the day-ahead schedules may be infeasible, in which case the ISO will need to redispatch units in the real-time when there is less flexibility to commit inexpensive units. In this example, congestion on intertie T2 will mean that a portion of the day-ahead scheduled import of 50 MW cannot flow over that intertie. Accordingly, the ISO will need to redispatch internal resources in the real-time to meet load. Currently, the ISO employs compensating injections in the real-time market to determine the amount of unscheduled flow on the interties in order to ensure accurate pricing and dispatch. First, the ISO relies on its state estimator solution[13] to provide current visibility of the total flow observed at the ISO boundaries, which includes ISO market schedules and unscheduled flow. Because the ISO system already has the market schedules, the software determines the compensating injections needed to account for unscheduled flow impacts from external sources and sinks on the ISO controlled grid to match the state estimator solution, which are presumed to continue in future intervals.[14] In more extreme circumstances, the ISO may need to use exceptional dispatch to correct for an infeasible day-ahead schedule. Any factor which increases the need to rely on exceptional dispatch has significant financial consequences.

In procuring energy in the real-time, the ISO often has to rely on more expensive generation, which increases the real-time congestion offset costs. Real-time congestion offset costs occur when there is congestion, and the market pays more than it charges to adjust generation. The difference is allocated to load.[15] In the illustrative example provided above, the ISO procured more expensive generation in the real-time, caused by higher congestion costs, to satisfy the same load. Table 2 below lists the substantial amounts of real-time congestion offset costs the ISO has experienced since 2010.

Table 2: Real-time Congestion Offset Costs

Year	$ (millions)
2010	$31
2011	$28
2012	$187
2013	$119
2014 YTD	$31

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13 The state estimator solution is a software program that provides the ISO with a near real-time assessment of system conditions within the ISO balancing authority area, including portions of the ISO balancing authority area where real-time information is unavailable. Tariff appendix A, definition of "State Estimator."

14 *See* transmittal letter for ISO tariff amendment, Docket Nos. ER09-556-000, *et al.*, at 8-9 (Jan. 15, 2009); *California Independent System Operator Corp.*, 126 FERC ¶ 61,262, at P 64.

15 Tariff section 11.5.4.2.

While the congestion offset costs are not solely caused by unscheduled flow, more accurate modeling of such flows would address one of the root causes of the uplift and would reduce the overall amount of such costs. Enhancing the modeling of the flows is especially important because the uplift associated with not accounting for unscheduled flow reflects a modeling discrepancy between the day-ahead and real-time that market participants can identify. Convergence bidding is in place to provide liquid trades to facilitate the convergence of the differences between two market financial outcomes that are based on demand and supply forces. However, to the extent there are differences in the day-ahead and real-time market modeling assumptions, convergence bidding will not be effective in closing that gap and will not eliminate the underlying issue of congestion offset costs caused by unscheduled flow.

Recognizing that unscheduled flows in the real-time are a significant concern, two groups within the Western Electricity Coordinating Council ("WECC") are examining the issue – the Unscheduled Flow Administrative Subcommittee ("UFAS") and the Path Operator Task Force ("POTF").[16] ISO representatives are members of and actively involved in both groups.

As a result of recent developments among WECC utilities, the ISO now has more data available on day-ahead system conditions in the West. Therefore, it will be feasible to enforce physical flow constraints on the interties in the day-ahead timeframe. Table 3 summarizes the ISO's current authority and the authority proposed in this filing to enforce scheduled and physical flow limits.

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[16] Materials related to these groups are available on the WECC website at http://www.wecc.biz/committees/StandingCommittees/OC/UFAS/default.aspx and http://www.wecc.biz/committees/StandingCommittees/JGC/POTF/default.aspx. In addition, see the UFAS presentation entitled USF Path 66 Analysis Update (Feb. 4, 2013), which discusses the magnitude and causes of unscheduled flow on the California Oregon Intertie during the 2010-12 time period. The UFAS presentation is available on WECC's website at http://www.wecc.biz/committees/StandingCommittees/OC/OC%20Informational%20Webinar040213/Lists/Presentations/1/OC%20USF%20Path%2066%20Analysis%20Update%20-%20Rich%20Salgo.pdf. The analysis in the UFAS presentation also discusses WECC's unscheduled flow mitigation procedure. That procedure is of limited scope – it applies to just six qualifying paths in WECC, and only one of those paths, the California Oregon Intertie, is operated by the ISO. The California Oregon Intertie is sometimes referred to as the "COI" or "Path 66."

Table 3: Authority to Model Unscheduled Flow

Authority	Day-ahead	Real-time
Account for unscheduled flow	Request authority	✓
Enforce physical flow constraints on the interties	Request authority	✓
Enforce physical flow constraints internally	✓	✓
Enforce scheduling constraints on the interties	✓	✓

As discussed below, the implementation of the modeling enhancements will allow improved modeling information to be reflected in the day-ahead. This, in turn, will result in fewer infeasible schedules that need to be managed in real-time. The modeling enhancements will also provide more accurate market pricing by incorporating congestion caused by unscheduled flow and respecting the physical limits of the ISO's interties in the day-ahead market. Further, it will reduce infeasible schedules in the day-ahead market. As a result, expensive redispatch and exceptional dispatch of resources will be required less often in the real-time under the modeling enhancements, and real-time congestion offset uplift costs will therefore be reduced.

3. Modeling of Unscheduled Flow and Greater Visibility of Conditions of the External Grid Will Support and Enhance the Energy Imbalance Market

The ISO plans to implement a new energy imbalance market with other balancing authority areas in the West effective October 1, 2014. In 2013, the ISO and PacifiCorp negotiated and received Commission approval of an implementation agreement that sets forth the terms under which the ISO will modify and extend its existing real-time energy market systems to provide energy imbalance market service to PacifiCorp.[17] Additional balancing authority areas may join the energy imbalance market in the future.[18]

Also, the ISO and stakeholders recently developed tariff revisions to

[17] *California Independent System Operator Corp.*, 143 FERC ¶ 61,298 (2013); Commission letter order, Docket No. ER14-1350-000 (Apr, 8, 2014) (accepting proposed revisions to the implementation agreement between the ISO and PacifiCorp).

[18] For example, on April 16, 2014, the ISO filed an implementation agreement in Docket No. ER14-1729 to allow NV Energy to participate in the energy imbalance market.

implement the energy imbalance market. On February 28, 2014, the ISO filed the tariff revisions in Docket No. ER14-1386 to provide interconnected balancing authority areas the opportunity to participate in the real-time market for imbalance energy that the ISO currently operates in its own balancing authority area. The ISO requested that the Commission accept the tariff revisions effective October 1.

The ISO did not initiate the stakeholder process to enhance its modeling approach with the energy imbalance market in mind. Even if there were no planned energy imbalance market, the ISO would still have proposed enhancements to the full network model, particularly in response to the April 2012 report regarding the September 8, 2011, event. Nevertheless, during the course of the stakeholder process that informed the ISO's decision to enhance the full network model, the ISO determined that enhancing the full network model would be beneficial for accurately modeling the balancing authority areas that will participate in the energy imbalance market. As such, the modeling enhancements reflect an important complement to the energy imbalance market that will significantly improve the quality of market solutions. Delaying the proposed modeling enhancements could result in less accurate dispatch and pricing as to those balancing authority areas once the energy imbalance market is implemented.

4. Expansion of the Geographical Area of the Full Network Model Will Enhance the ISO's Ability to Make Use of Newly Available Operational Data

Until recently, the limited exchanges of data between balancing authority areas in the WECC region have constrained the extent to which the ISO could model the systems and flows of other balancing authority areas. The ISO has previously expressed its interest in expanding its modeling of the greater network system and expressed the limitations on doing so based on the limited availability of data.[19] The Commission also previously recognized that the ISO's ability to model external systems is limited by the extent to which the ISO has the information to do so.[20] This limitation has been addressed by the increased exchange of data made possible following the September 8, 2011, event.

The ISO has proven its ability to successfully model external systems through its base market model through its modeling of external balancing authority areas for purposes of supporting commercial obligations. For example, the full network model currently includes (1) 500 and 345 kV transmission, and

[19] *See, e.g.*, *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 43 (2006).

[20] *Id.* at P 45.

equivalent network models for lower voltage transmission facilities,[21] in Arizona, southern Nevada, New Mexico, and small portions of Utah and Colorado, (2) transmission lines that connect the ISO's intertie scheduling points to the 500 and 345 kV transmission systems in those states, including the looped transmission of the Imperial Irrigation District and the Los Angeles Department of Water and Power, (3) an equivalent model of transmission in Comisión Federal de Electricidad (Mexico), and (4) the looped transmission grid in the Balancing Authority of Northern California and Turlock Irrigation District balancing authority areas. The ISO has included external systems in its base market model and successfully managed congestion based on these inclusions.

Because the base market model is based on a forward-looking time horizon, rather than the current view of system conditions that is modeled and captured in the energy management system, the base market model and the energy management system's network model reflect separate representations of external transmission systems. For example, while the energy management system network model reflects the actual conditions on the modeled elements, the lack of outage data from outside of the ISO balancing authority area has limited the ISO's ability to reflect these conditions in the base market model.

Peak Reliability has recently made a larger set of data available to grid operators through a WECC universal nondisclosure agreement.[22] The data will enable the ISO to use the same network model for the base market model and the energy management system for the balancing authority areas that were affected by the September 8, 2011, outage event.[23] The availability of these data will enable the ISO to reflect outages in these areas while operating the

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21 Equivalent network models is an engineering term that reflects the use of a model for lower voltage transmission facilities that replace portions of the physical network with a simplified topology that retains the same electrical properties that are considered important, but does not reflect all the specific elements. The current full network model retains the actual 500 and 345 kV transmission, as well as an equivalent model of lower voltage transmission, and a 220 kV model of the external systems in the Southwest. Similarly, the model of Comisión Federal de Electricidad retains the physical lines between the ISO's interties at Tijuana and La Rosita, but does not retain lines that do not connect these interties.

22 Peak Reliability is a company wholly independent of WECC that performs the reliability coordinator and interchange authority functions in the Western Interconnection. Peak Reliability was formed as a result of the recent bifurcation of WECC into a regional entity (WECC) and a regional coordinator (Peak Reliability). *See North American Electric Reliability Corp.*, 146 FERC ¶ 61,092 (2014).

23 As stated above, the interconnected balancing authority areas affected by the September 8, 2011, outage event were Arizona Public Service Company, Imperial Irrigation District, Western Area Power Administration – Lower Colorado, and Comisión Federal de Electricidad. Salt River Project is highly interconnected with Arizona Public Service Company and will be included in the model at the same level of detail as Arizona Public Service Company and Western Area Power Administration – Lower Colorado.

markets assuming the Commission accepts the tariff revisions proposed in this filing.[24]

As part of the energy imbalance market implementation effort, the ISO is modeling in detail balancing authority areas that have agreed to participate in such energy imbalance market when it goes into effect October 1, 2014. Specifically, the balancing authority areas that are being modeled are PacifiCorp East and PacifiCorp West, which include transmission in Oregon, Washington, Idaho, Utah, and Wyoming, in addition to an area of California that is not in the ISO balancing authority area. The transmission used by PacifiCorp West includes contract rights through Bonneville Power Administration and Idaho Power Company, which must be modeled in similar detail as PacifiCorp, using the model data available through Peak Reliability. Because Bonneville Power Administration's transmission is highly interconnected with several balancing authority areas in the Pacific Northwest, these areas must also be modeled at the same level of detail.[25] In addition, PacifiCorp East's transmission system runs in parallel with 345 kV transmission in Colorado (owned by Public Service Colorado and Western Area Power Administration – Colorado Missouri), and NV Energy's transmission system connects to both the ISO and PacifiCorp transmission systems. These parallel paths must be modeled for accurate congestion management in the energy imbalance market through use of the same network model for both the energy management system and the base market model. The Commission's acceptance of the energy imbalance market tariff revisions in Docket No. ER14-1386 will allow the ISO to model these balancing authority areas consistent with its existing tariff authority to model external balancing authority areas.[26] The tariff revisions proposed in this filing will allow the ISO to make the best use of recently available data on these balancing authority areas for purposes of operating its system more reliably.[27]

The ability to use the same network model for the base market model and the energy management system will allow the ISO to replace the base market

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[24] Because the ISO has a dynamic schedule with a generator in New Mexico that is connected at a lower voltage that is not represented in the energy management system's network model, the ISO will continue to use an equivalent model for New Mexico that is similar to what is currently used, until the energy management system's network model includes this section of transmission.

[25] These balancing authority areas include: Avista; Chelan, Douglas, and Grant county public utility districts; Portland General Electric; Puget Sound Energy; Seattle City Light; and Tacoma Water and Power.

[26] *See* tariff section 27.5.1.1. ("In the Base Market Model, external Balancing Authority Areas and external transmission systems are modeled to the extent necessary to support the commercial requirements of the CAISO Markets.").

[27] *See* proposed modification to tariff section 27.5.1.1.

model's separate representation of the looped transmission grid in the Balancing Authority of Northern California and Turlock Irrigation District balancing authority areas with the energy management system's network model. This will better allow the ISO to reflect outages in these areas and improve the management of the ISO controlled grid.[28]

D. Stakeholder Process

In June 2013, the ISO initiated a process to develop with stakeholders a proposal to enhance the full network model.[29] The stakeholder process was extensive and included a number of stakeholder meetings, conference calls, opportunities for written stakeholder comments, presentations and papers issued by the ISO, and revisions to the proposal based on stakeholder comments and the ISO's own review.[30] The stakeholder process included the development of the tariff revisions contained in this filing.[31]

Stakeholders generally supported the goal of enhancing the full network model. Some stakeholders did have specific concerns with the proposal as it was developed in the stakeholder process. Those concerns are discussed below.

The ISO's Market Surveillance Committee reviewed the proposal for

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[28] This is not a complete list of all modeled balancing authority areas. The ISO will post a bulletin that lists all of the areas that will be included in the full network model.

[29] Materials regarding the stakeholder process for the modeling enhancements are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/FullNetworkModelExpansion.aspx. These materials refer to "expansion" of the full network model. For purposes of this filing, the ISO has determined that it is more accurate to describe the full set of ISO proposals as modeling enhancements, which include the modeling of unscheduled flows in the day-ahead market described in Section III.A, the enforcement of power flow constraints in the day-ahead market described in Section III.B, and the expansion of the full network model topology described in Section III.C below.

[30] Two of the papers issued in the stakeholder process are provided in this filing for ease of reference. The first of the papers is entitled Full Network Model Expansion – Draft Final Proposal (Dec. 30, 2013) ("draft final proposal"). The draft final proposal is provided in attachment C to this filing. The second paper is entitled Full Network Model Expansion Draft Final Proposal Addendum: Pre-Implementation Analysis (Jan. 23, 2014) ("addendum to draft final proposal"). The addendum to draft final proposal is provided in attachment D to this filing.

[31] A list of key dates in the stakeholder process is provided in attachment G to this filing. An example of the ISO's responsiveness to stakeholder input was that the ISO originally proposed to model imports and exports in the full network model as having sources and sinks distributed at locations outside the ISO balancing authority area. However, the ISO deferred this aspect of its proposal to a future separate stakeholder initiative based on stakeholder concerns with the potential impacts of such an approach.

enhancing the full network model and issued an opinion expressing strong support for the proposal.[32] The Market Surveillance Committee noted that the planned extension of the ISO network model to encompass a broad region outside the ISO controlled grid is consistent with the scope of the network models already used by independent system operators in the eastern United States.[33] The Committee found that the ISO's proposed approach for estimating unscheduled flows and modeling them in the day-ahead market would not be unique to the ISO, as it is also used by eastern independent system operators who are extensively impacted by loop flow.[34] The Market Surveillance Committee concluded that testing and implementation of modeling enhancements is an essential first step on the road towards better regional integration and more accurate system modeling.[35] The Market Surveillance Committee also discussed stakeholder concerns with elements of the proposal and concluded that none of them are a sufficient reason for delaying or significantly revising the plan for developing and testing the modeling enhancements.[36]

At its February 6, 2014 meeting, the ISO Governing Board approved the proposal developed by the ISO and stakeholders for enhancing the full network model.[37] In response to stakeholder requests, the ISO committed to analyze the results of its modeling of unscheduled flow during a test period and demonstrate the accuracy of such modeling prior to implementing the modeling of unscheduled flow in the day-ahead market. ISO management further committed to report on the results of this analysis to stakeholders and the ISO Board during its September 2014 meeting.

The ISO conducted a further stakeholder process to obtain input on the tariff language implementing the proposal approved by the Board. This process included the publication of draft tariff revisions followed by an opportunity for

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[32] Opinion on Implementation of the Full Network Model (adopted Jan. 30, 2014) ("MSC opinion"). The MSC opinion is provided in attachment E to this filing and is available on the ISO website at http://www.caiso.com/Documents/FullNetworkModelImplementation-MSC_OpinionJan_2014.pdf.

[33] MSC opinion at 4.

[34] *Id.* at 9.

[35] *Id.* at 1.

[36] *Id.* at 2.

[37] Materials related to the Board's February 6 meeting are available on the ISO website at http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx. These materials include a Board memorandum issued on January 30, 2014 ("Board memorandum"), which is provided in attachment F to this filing.

stakeholder comments, a conference call to discuss the draft tariff revisions, and the publication of responses to stakeholder comments along with an updated draft of the tariff revisions.

III. Description of the ISO's Proposal

The ISO proposes to amend its tariff to allow the ISO to adopt three important modeling enhancements. First, the ISO proposes to model unscheduled flows that occur within the ISO balancing authority area based on available information for other balancing authority areas. Second, the ISO proposes to enforce physical flow constraints on the interties in the day-ahead market. The ISO already performs such modeling and enforces such constraints in the real-time market. The ISO proposes to add these features to its administration of the day-ahead market because it now has access to additional data on system conditions in the West, which will allow the ISO to more accurately model these flows in the day-ahead timeframe. This will provide significant reliability benefits by allowing day-ahead schedules to reflect next-day operating conditions external to the ISO controlled grid, such as generation and transmission outages and scheduled interchanges, all of which can significantly impact system operations.

Third, the ISO proposes to extend its modeling of the external interconnected grid beyond the ISO controlled grid and to more accurately reflect the anticipated day-ahead and actual real-time system topology of other balancing authority areas in the West. As discussed above, the ISO already models the external system to the extent it has access to reliable information to support its commercial obligations. The ISO's expansion of the external topology in its base market model is also made possible by the increased availability of information regarding other balancing authority areas in the West.

The proposed modeling enhancements will provide more accurate market pricing by incorporating congestion caused by unscheduled loop flow and respecting the physical limits of the ISO's interties in the day-ahead market. Also, it will reduce infeasible schedules in the day-ahead market that result in expensive redispatch of resources in the real-time market and increase real-time congestion uplift costs. Below, the ISO provides a more detailed explanation of how the proposed enhancements will produce these benefits.[38]

[38] A table summarizing the proposed revisions to each tariff section is provided as attachment H to this filing.

A. Day-Ahead Modeling of Unscheduled Flows from Other Balancing Authority Areas Will Enhance Reliability and Promote Market Efficiency

As discussed in Section II.C above, the ISO has identified a number of reasons why it is appropriate to implement modeling enhancements in the ISO's markets now that the ISO has access to more data regarding day-ahead system conditions in other balancing authorities. The ISO has developed a detailed and sound methodology for using this data to create base schedules at external locations in interconnected balancing authority areas and to estimate day-ahead unscheduled flow. This methodology will provide the ISO's market software with visibility of unscheduled flow that the ISO can expect from transactions not involving the ISO. Incorporating day-ahead estimates of unscheduled flow in the network model used in the day-ahead market will result in more feasible schedules in the real-time because the full network model will reflect the loop flows. Moreover, calculating the loop flows in the day-ahead timeframe will provide the ISO with more time to ensure that it can commit and dispatch the resources needed to address expected real-time conditions.[39] This enhanced modeling framework will also be able to reflect the most recent information on outages, derates, and contingencies. As explained below, an important aspect of the ISO's methodology will provide the ISO with the discretion to determine whether available input data is sufficiently accurate to serve as the basis for day-ahead unscheduled flow estimates.[40]

Today, the ISO models unscheduled flows in the hour-ahead and real-time markets based on real-time information; however, the ISO does not have a comparable accounting of unscheduled flow in the day-ahead market. The ISO requests authority to extend its current Commission-approved practice of accounting for unscheduled flow to the day-ahead market. Approval of the instant tariff amendment will result in the ISO having the ability to model unscheduled flows in all of its markets. To achieve this result, the ISO proposes to revise section 27.5.1.1 of its tariff to state that the ISO markets optimizations will factor in forecasted unscheduled flow at the interties consistent with the requirements specified in the business practice manuals. For reasons similar to those that led the Commission to find it just and reasonable to model unscheduled flows in the hour-ahead and real-time markets,[41] the Commission should find it just and reasonable to extend such authority to the day-ahead

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[39] In the day-ahead timeframe, the ISO has access to more resources because it can select resources with longer start-up times for unit commitment.

[40] More details on the ISO's methodology and the use of discretion in applying that methodology are provided below.

[41] *See California Independent System Operator Corp.*, 126 FERC ¶ 61,262, at P 72.

market.

The ISO's methodology for measuring unscheduled flow in the day-ahead involves creating base schedules for the anticipated unscheduled flows that set the amount of generation equal to the sum of the amounts of demand and the net scheduled interchange in the balancing authority area (treating losses as part of a balancing authority area's demand).[42] The ISO will include these schedules in the base market model that will be created under the ISO's proposal.

Consistent with Commission precedent finding that certain details regarding the ISO's unscheduled flow methodology do not need to be included in the tariff, the ISO will set forth many of the details for creating schedules for interconnecting balancing authority areas in the applicable business practice manual.[43] In support of its request for the authority to model unscheduled flow in the day-ahead market, the ISO provides detail below on how it will model schedules for other balancing authority areas. This will facilitate the Commission's understanding of the steps the ISO must undertake to respond to recommendations of the April 2012 report and to provide the reliability and market efficiency benefits described in this filing. A detailed example illustrating how schedules will be created for use in the base market model is provided in the draft final proposal provided as attachment C to this filing.[44]

Allowing the ISO to exercise some degree of discretion is necessary because it is reasonable to expect that issues will arise from time to time regarding the accuracy of the information. Under these circumstances, requiring the ISO to hard-wire a specific methodology for modeling other balancing authority areas without having any discretion to assess the accuracy of available information could produce inappropriate and inefficient market results. No hard-wired methodology, no matter how detailed it is, can ensure that the input data will always be sufficiently accurate to avoid the possibility of inaccurate results. The business practice manual will set forth the details on when the ISO will use available data to forecast unscheduled flow at the interties. The ISO's proposal presents a balanced approach to addressing the potential for inaccurate results and ensures that achievement of the reliability and market efficiency benefits associated with the proposed modeling enhancements will not be unduly delayed or put off indefinitely due to the desire for perfect input data.

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[42] Draft final proposal at 7, 16.

[43] *See California Independent System Operator Corp.*, 126 FERC ¶ 61,262, at PP 70-72 (accepting the ISO's explanation that its unscheduled flow methodology should be set forth in the business practice manual).

[44] Draft final proposal at 30-34.

The discretion sought by the ISO is consistent with discretion afforded other system operators. The ISO has reviewed how other independent system operators and regional transmission organizations document their modeling of loop flow. Based on this review, the ISO has found only high-level references to the treatment of loop flow in their tariffs.[45] These system operators provide additional detail in their business practice manuals and technical bulletins, but even with this additional detail, they have a large degree of flexibility in implementing their approach to the treatment of loop flow.[46] The same approach is appropriate here.

The Market Surveillance Committee supports an approach which provides the ISO with discretion to determine which data to use to model unscheduled flow from other balancing authority areas.[47] Specifically, the Market Surveillance Committee notes that:

> the proposal is to reserve for the CAISO the discretion to use the best information available to it in order to model loopflows. If the information provided by some balancing authority areas does not enhance the CAISO's ability to accurately predict realtime loopflows, there is no obligation for the CAISO to use that information.[48]

The Market Surveillance Committee agrees with this aspect of the ISO's proposal, concluding that the proposed discretion is an important element of the proposal:

> the Full Network Model design envisions that the CAISO will actively monitor the performance of the design to ensure that it is achieving its intended goal of improving loopflow forecasts, and we agree that it is important that the CAISO actively carry out this

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[45] *See, e.g.*, NYISO Market Administration and Control Area Services Tariff, Section 17.1.1.1.1 ("In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon."); PJM OATT, Attachment K, Section 5.3 ("When there are agreements between the LLC and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the Total Congestion Charges that are distributed in accordance with Section 5.2.").

[46] *See, e.g.*, NYISO Technical Bulletin 213: Interface Pricing Method for Modeling Unscheduled Power Flows; PJM Manual 03: Transmission Operations, Section 5.

[47] MSC opinion at 8.

[48] *Id.*

objective.[49]

The proposed discretion will be exercised within the context of a detailed methodology which takes advantage of the additional data now available on system conditions in the West. As discussed above, until recently the ISO did not have sufficient data from other balancing authority areas to enforce physical flow constraints on the interties and to model unscheduled flow in the day-ahead market. As a result of recommendations made in the April 2012 report of Commission and NERC staff on the September 8, 2011, system disturbance, however, sufficient sharing of day-ahead system data among balancing authorities across the Western Interconnection is now in place. The ISO will make use of the larger set of data now available to model the generation, demand, and net scheduled interchange of other balancing authority areas.

The most important data the ISO will use to implement these modeling enhancements consists of six components: (1) telemetry data; (2) load and generation distribution factors; (3) demand forecasts; (4) net interchange schedules; (5) generation forecasts; and (6) generation and transmission outages. The telemetry data and load and generation distribution factors will be based on the ISO's state estimator.[50] Demand forecasts can be provided to the ISO by Peak Reliability as the reliability coordinator for the WECC region.[51] The ISO can obtain the net interchange schedules using the WECC interchange tool, which provides information by intertie for each balancing authority area. The ISO intends to use these data sources as a starting point. Recognizing that all data for each balancing authority area may not be available, the ISO will produce an estimate based on the best available data. As the ISO collects more information, it can compare the completeness of these data at different reporting times. The ISO can accomplish this using an historical statistical analysis such as a regression technique to create the best available modeling input by scaling or estimating the expected interchange levels. The ISO discusses the difference in reporting times in greater detail below. Because generation in a balancing authority area must equal the sum of demand and net schedule interchange, the

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49 *Id.*

50 For example, the default generation and load distribution factors will be adapted from the state estimator solution and maintained in an electronic library for various seasons, types of days (*e.g.*, workday, weekday/holiday), and periods during days (*e.g.*, on-peak, off-peak), and normalized for known outages.

51 In addition to daily updates, the reliability coordinator will also have demand forecasts for the next several days for each interconnected balancing authority area, so data should consistently be available to the ISO. Nevertheless, the ISO will rely on its own analysis and validation, for example, to true-up or estimate information that was not submitted to WECC accurately. The ISO can further fine-tune the demand forecasts if needed by scaling the forecasts up or down based on a historical analysis of actual demand.

ISO can derive the generation forecasts from that sum.[52] Lastly, the ISO can incorporate generation and transmission outages reported to the reliability coordinator or known to the ISO into the schedule used in the base market model. Also, balancing authorities can directly provide these six types of data directly to the ISO (*e.g.*, pursuant to non-disclosure agreements).[53]

The ISO will compare the hourly demand forecasts from the WECC reliability coordinator against actual hourly demand by balancing authority area. The ISO will retrieve the net scheduled interchange by balancing authority area pair via the WECC interchange tool. During the validation, the ISO will compare data available in the morning (approximately 9 a.m.) with historical tag data. The historical tag data will form the foundation of a forecast, and the morning data will be adjusted to the forecasted level of interchange. The ISO will track the accuracy of the morning projections against the historical tag data. In analyzing the historical tag data, the ISO will look at both historical data based on the day-ahead tag submission deadline (at 3 p.m.) and all tags submitted by the real-time deadline (20 minutes before flow).

Based on historical values from the state estimator, the ISO will use generation distribution factors and load distribution factors to calculate the distribution of generation, demand, and net scheduled interchange for each balancing authority area that is modeled under the proposed enhancements. The ISO will then account for imports to the ISO system that clear the ISO market by modeling them as incremental to the base schedules of the source balancing authority area derived for the base market model. The ISO will account for exports from the ISO system that clear the market in the model by showing exports as decremental to the base schedules within that balancing authority area.

As noted above, the ISO will not use schedule data for modeling unscheduled flow in the base market model that the ISO believes are not sufficiently accurate. The ISO will compare the demand forecasts to a historical analysis of actual demand, and the ISO can fine-tune the demand forecasts if needed by scaling the forecasts up or down. Similarly, net scheduled interchange(s) and/or entire schedule(s) may be adjusted to neutralize their

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[52] For example, if a balancing authority area has 10,000 MW of native demand and 500 MW of net energy export, its native generation must be 10,500 MW in order to meet the native demand and support the net energy export.

[53] Draft final proposal at 16-17. To reflect the use of these data sources, the ISO proposes to revise tariff section 27.5.1.1 to state that, in formulating the market models for the ISO market processes (except for specific intertie locations as specified in the business practice manual), the power flow parameters developed from applicable data sources, including available outages information, system status data, and the state estimator for the real-time dispatch, are applied to the base market model.

impact. For example, in the event that input data are not sufficiently accurate, the ISO can make adjustments by not incorporating the base schedules and setting the net scheduled interchange in the balancing authority areas it is modeling to zero. The ISO will have the flexibility to make adjustments for one, multiple, or all interconnected balancing authority areas as the situation requires.[54]

The ISO will model the flow resulting from the schedules, as well as import and export bids cleared in the ISO market, to reflect congestion in the locational marginal price due to physical flow for each scheduling point.[55] The ISO will incorporate this additional source of congestion into the locational marginal price for imports and exports. Thus, the price at an intertie will reflect two sources of congestion: (1) the existing source of congestion based on each intertie's scheduling limit and (2) a new source of congestion that reflects congestion due to modeled physical flow.[56]

The ISO's proposed approach for estimating loop flows and modeling them in the day-ahead market is not unique. It is also used by eastern independent system operators and regional transmission organizations that are extensively impacted by loop flows, such as the Midcontinent Independent System Operator ("MISO") and PJM Interconnection ("PJM").[57] The MISO had significant real-time congestion rent shortfalls during 2005, its initial year of operation, which it substantially reduced during 2006 and 2007. It has continued to reduce congestion rent shortfalls in subsequent years through improved modeling of loop flows.[58]

The ISO's proposal to model unscheduled flow in the day-ahead market is just and reasonable because, as discussed in greater detail above in Section II.C.2, the lack of such modeling results in the production of day-ahead schedules and prices that do not reflect flows on the system that can now be anticipated in an accurate manner. The current methodology essentially forces the day-ahead market to assume that *there is no unscheduled flow*. Because unscheduled flows do occur in the real-time, actual flows not scheduled in the

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54 Draft final proposal at 18; addendum to draft final proposal at 3-4.

55 The ISO proposes to revise the defined term "scheduling point" in tariff appendix A to mean a location in the base market model at which scheduling coordinators may submit intertie bids in the ISO markets.

56 Draft final proposal at 8.

57 MSC opinion at 9; *see also* MISO Business Practices Manual No. 010: Network and Commercial Models, Section 3; PJM Manual 03: Transmission Operations, Section 1.5.

58 MSC opinion at 9 (citing MISO materials).

day-ahead or real-time will require the redispatch of resources, which may be potentially more costly, to address the unanticipated flows. The ISOs ability to operate the system reliably will be substantially improved if the day-ahead schedules produced in the day-ahead market better reflect actual flows and do not require the ISO to rely on real-time operations only.

B. Enforcement of Constraints on the Interties in the Day-Ahead Market for Both Scheduled and Physical Flow Will Enhance Reliability and Congestion Management Efforts

As discussed above, the ISO enforces the physical flow limits on transmission facilities located within the ISO balancing authority area in both the day-ahead and real-time. The ISO currently enforces the scheduled flow limits on the interties in the day-ahead and real-time, but enforces the physical flow limits on the interties only in the real-time. The ISO manages infeasible schedules due to unscheduled flows and physical flow limits on the interties in the real-time, when there is less flexibility to commit units. This can lead to redispatch of expensive generation or even exceptional dispatches to resolve the infeasible schedules, thereby resulting in real-time congestion offset uplift costs. The modeling enhancements that are now possible because the ISO has access to additional data on system conditions in the West will allow the ISO to model unscheduled flow and to enforce physical flow constraints on the interties in the day-ahead market.

The ISO proposes to respect both scheduled and physical flows on the interties through the use of a two-constraint approach.[59] The ISO's use of the two-constraint approach conforms with the two-constraint methodology that the Commission recently accepted in its order on the ISO tariff amendment to implement real-time market design enhancements.[60] For similar reasons, the Commission should approve the use of the two-constraint approach (*i.e.,* enforcing both scheduling constraints and physical flow constraints) for the day-ahead market.

The ISO proposes to revise tariff section 31.8.1 and add new tariff section 31.8.2 to reflect the use of the two-constraint approach discussed above.[61]

The following approach enforces two constraints. In the integrated

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[59] Draft final proposal at 26-28.

[60] *See California Independent System Operator Corp.*, 146 FERC ¶ 61,204, at P 102 (2014).

[61] A hypothetical example illustrating how scheduling constraints and physical constraints will be enforced on the interties is provided in the draft final proposal. Draft final proposal at 34-36.

forward market, the ISO will continue to enforce a scheduling constraint and will now also include a physical flow constraint, each of which will consider both physical and virtual bids.[62] This will result in consistent pricing for both physical and virtual awards, as is the case under the Commission-approved real-time market design enhancements. The scheduling constraint will continue to be based on the assessment of intertie bids submitted by the scheduling coordinators relative to the available transfer capability of the specific intertie location. This will ensure that contract paths are honored and will be used for e-tagging intertie schedules. The physical flow constraint will be based on the modeled flows for the intertie, taking into account the actual power flow contributions from all resource schedules in the full network model against the available transfer capability of the intertie. Unlike the scheduling constraint, the contributions of intertie schedules towards the physical flow limit will be based on the shift factors calculated from the network model, which reflects the amount of flow contribution that change in output will impose on an identified transmission facility or flowgate. Each intertie will have a single total transfer capability and the scheduling limit and physical flow limit will be compared against the intertie's capacity. The scheduling limit and physical flow limit are not necessarily equal to each other.[63]

In the residual unit commitment, the ISO will continue to enforce two constraints that only consider physical awards with respect to contract path limits (*i.e.*, virtual awards cannot provide counterflow to physical awards). This was implemented with the real-time market design enhancements recently approved by the Commission, under which only those physical awards that also clear the residual unit commitment process are allowed to be e-tagged prior to the fifteen minute market, in order to ensure that e-tagged schedules do not exceed an intertie's capacity.[64]

This use of two constraints, in conjunction with improved modeling of day-ahead and real-time conditions, will help the ISO to minimize and manage unscheduled flows. Under the enhanced modeling approach proposed in this tariff amendment, unscheduled flows will be incorporated into the day-ahead

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[62] The two-constraint methodology is not relevant to the real-time market because that market does not consider virtual bids. Draft final proposal at 26.

[63] The scheduling limit "is a scheduling constraint based on the intertie declared in intertie bids against the operational limit of the intertie. This will ensure that contract paths are honored and will be used for tagging intertie schedules." Draft final proposal at 27. The physical flow limit "is a physical flow constraint based on the modeled flows for an intertie taking into account the actual power flow contributions from all resource schedules in the FNM against the operational limit of the intertie." *Id.* at 28. The physical flow limit can be higher than the scheduling limit, depending on the intertie and system conditions.

[64] *See California Independent System Operator Corp.*, 146 FERC ¶ 61,204.

market, and the day-ahead market will produce feasible schedules with prices that more accurately reflect the conditions that will be experienced in real-time. By expanding the full network model to include other balancing authority areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how they may affect the ISO market. The ISO proposes to model and enforce physical flow limits on the interties, as appropriate, in the day-ahead so that the combination of unscheduled flow and flow from accepted market schedules does not exceed the physical capabilities of the interties. Including these modeling improvements in the day-ahead and real-time markets will help the ISO to create feasible schedules, enforce reliability, price market transactions more accurately, and reduce the use of redispatch and exceptional dispatch.[65] Making these improvements to the ISO market through enhancements to the full network model is consistent with Commission precedent.[66]

One stakeholder opposed enforcing physical flow limits on the interties in the day-ahead, in addition to enforcement of the current scheduled flow limits, on the grounds that it will change the prices on the interties and limit intertie schedules in the day-ahead market in a way that may not reflect market participants' scheduling priority in the interconnected balancing authority areas. This stakeholder suggests that enforcing physical flow limits is inconsistent with the open access transmission tariff framework in the Western Interconnection and proposes that any reductions to infeasible imports be achieved in a coordinated manner through adjustment of the available transmission capacity.

These objections are misplaced. As an initial matter, it would be contrary to the recommendations of the Commission and NERC staff for the ISO to forego an opportunity to better reflect next-day operating conditions external to the ISO system. Indeed, the ISO already enforces physical flow limits in both the day-ahead and the real-time within the ISO balancing authority area and in the real-time on the interties. The ISO merely proposes to extend this practice to the interties in the day-ahead so that the day-ahead model better reflects expected real-time conditions. The Commission has already found that it is just and reasonable to enforce physical flow limits in real-time; there is no legitimate basis to claim that it is unjust and unreasonable to apply the same practice to

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[65] Board memorandum at 3.

[66] *See California Independent System Operator Corp.*, 126 FERC ¶ 61,150, at P 33 n.59 (2009) ("We note that not only would a robust full network model and enhanced software functionality . . . [help to] reduce the CAISO's reliance on Exceptional Dispatch, but these improvements could also have other positive market impacts."); *id.* at P 83 ("We expect that as the CAISO gains operational experience and implements enhancements to the [Market Redesign and Technology Upgrade] software and full network model, the need for Exceptional Dispatch will decrease.").

the day-ahead.[67] Physical flow constraints exist regardless of whether they are in the market model or not. Thus, enforcing physical flow limits in the day-ahead market will reflect that reality in the ISO's market solutions and prices on the interties. In this way, intertie transactions will reflect the appropriate congestion costs caused by unscheduled flow, thereby sending more accurate pricing signals to neighboring balancing authority areas. The ISO should not be compelled to produce less accurate price signals now that improved data on day-ahead system conditions is available simply because other parts of the West follow a contract path transmission service framework.

The ISO's approach will also improve alignment of the ISO's day-ahead and real-time markets. The ISO already enforces physical flow limits in the real-time market. The ISO's proposal to also enforce the power flow constraint in the day-ahead market merely aligns this practice between the two markets. This helps in eliminating modeling differences between the two markets, which the ISO and its market participants previously endured due to lack of available data. Having access to the additional data eliminates the need for this inconsistency. Further, as the Market Surveillance Committee explains, there is nothing unique about the ISO's proposal; PJM and the New York Independent System Operator ("NYISO") already model physical constraints on their tie lines.[68]

The ISO proposes not to enforce the physical flow limits on the interties in the day-ahead in three instances.[69] First, the ISO will not enforce Interties physical flow constraints at interties for which the ISO is subject and privy to contractual arrangements that provide for the management of unscheduled flows using other procedures. For example, the ISO plans to maintain the current status quo modeling and enforcement of the scheduled flow limits for the California Oregon Intertie, where the ISO is the path operator. For the California Oregon Intertie, the ISO will continue to enforce only the scheduled flow limit in the day-ahead and real-time markets, enforce physical flow limits of the underlying individual lines constituting the ISO controlled grid in the day-ahead and real-time markets, and use WECC's unscheduled flow mitigation procedure in real-time.[70] This exception is appropriate because under such arrangements,

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[67] *See California Independent System Operator Corp.*, 137 FERC ¶ 61,025, at PP 7, 20 (2011)

[68] MSC opinion at 12-13; *see also* PJM Manual 03: Transmission Operations, Sections 1.3, 1.5.3-1.5.6; NYISO Manual 24: Reliability Analysis Data Manual, Sections 1.4, 3.

[69] *See* proposed tariff section 31.8.2.

[70] This procedure only applies to six qualified paths in WECC, and the California Oregon Intertie is the only one of these paths that the ISO operates. The ISO has neither the responsibility nor the authority to implement the WECC unscheduled flow mitigation procedure for the other five qualified paths.

the ISO and the parties to the agreement must make use of the WECC-wide unscheduled flow mitigation procedure to share in the cost of redispatch and reduction of schedules due to unscheduled flow observed in the real-time. This exception also respects currently effective multi-party operating agreements governing the operation of the California Oregon Intertie, including the California Oregon Intertie Path Operating Agreement.[71]

The ISO also proposes that it have the flexibility to not enforce the physical flow limits in cases in which it has determined it cannot enforce the power flow constraints due to modeling inaccuracies, including inaccuracies in available data. This exception is important because it is possible that a neighboring control area will not provide accurate data, or there might be a disruption in the provision of such data that renders the results of the day-ahead market less accurate than if the ISO had not enforced the power flow constraint. Lastly, the ISO proposes to retain the flexibility not to model such constraints if it has determined that enforcing the power flow constraints at locations could result in adverse reliability impacts.

For parties that have signed a non-disclosure agreement, the ISO proposes to provide protected data regarding transmission constraint limits one day after the applicable trading day pursuant to revised tariff section 6.5.10.1.4. The tariff currently allows for provision of the information three days after the applicable trading day. Further, pursuant to proposed tariff section 6.5.10.1.5, the ISO will provide such parties with protected data regarding unscheduled flow estimates for each intertie after the results of the day-ahead market and the real-time market are posted.

For parties that have signed a non-disclosure agreement, the ISO is considering providing protected data regarding transmission constraint limits one day after the applicable trading day. Section 6.5.10.1.4 of the tariff currently allows for provision of the information three days after the applicable trading day.[72] Further, pursuant to proposed tariff section 6.5.10.1.5, the ISO will provide such parties with protected data regarding unscheduled flow estimates for each intertie after the results of the day-ahead market and the real-time market are posted.

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71 Draft final proposal at 20-22. A few stakeholders were under the incorrect impression that continuing to enforce only the scheduled flow limit in the day-ahead and real-time markets for the California Oregon Intertie is contrary to today's practices and agreements. The ISO's proposal continues today's practices concerning the California Oregon Intertie.

72 The ISO intends to make a change to this section in a subsequent filing to allow the data to be released the next day instead of three days out.

C. Extension of the Full Network Model Will Enhance Market Operations

As noted above, the enhanced modeling now possible due to the availability of additional data on day-ahead conditions in other parts of the WECC is the foundation on which the benefits of the ISO's proposal rests. To reflect this improved modeling framework, the ISO proposes to revise tariff section 27.5.1.1 to state that, in the base market model, external balancing authority areas and external transmission systems are modeled to the extent necessary to improve the accuracy of the ISO market solutions for purposes of reliable operations, in addition to the existing authority to be able to do so in support of the "commercial requirements of the CAISO Markets."

The ISO notes that in certain circumstances it has been able to reflect the topology, *i.e.*, the transmission lines and transformers, of the external systems in its market models and model flows from such systems in the ISO's markets today. The ISO has been able to do so reliably in these circumstances. However, the ISO has been limited in its ability to model external systems because it previously lacked sufficient visibility into the specific locations of sources and sinks in the external system.

The ISO proposes to amend section 27.5.1.1 to clarify that the ISO may extend visibility into the extended network to support reliable operation of its grid. The April 2012 report provided clear guidance and support for the principle that, in operating one's own balancing authority area, a balancing authority cannot ignore the external systems to which it is interconnected. The ISO operates its system reliably through its markets and has been unable to take into account the topology of external systems in the day-ahead timeframe due to the lack of available data. However, with the provision of the necessary data by Peak Reliability, the ISO can now enhance its modeling efforts, and thereby improve congestion management and market efficiency.

The ISO will include the sources and sinks of the external balancing authority areas in the West in the base market model in both the day-ahead and real-time markets. As discussed above, the current limitations of the model create schedules and prices that at times may not reflect how the power actually flows, thereby requiring the ISO to resort to out of market measures to manage congestion reliably. Reflecting the extended topology will eliminate these blinders and enhance the ISO's management of transmission congestion.

One stakeholder commented that the ISO should prove that the pricing changes that will result from this change will be just and reasonable. It has been just and reasonable for the ISO to manage its system without full consideration of day-ahead system conditions and the topology of external systems (and their impacts on flows on the ISO grid) given the data limitations. It logically follows that if it has been just and reasonable for the ISO to model system conditions without having the full benefit of relevant data, it certainly must be just and reasonable to model such conditions using more accurate data. This stakeholder is essentially claiming that a market based on less transparency and information is better than a market based on more transparency and information. That is contrary to the Commission's findings regarding the benefits of using the most accurate network model in markets based on locational marginal pricing.[73] With the removal of the aforementioned data limitations, the ISO should not be forced to operate its system and administer its markets without clear recognition of the external system. Under the ISO's proposal, day-ahead prices will reflect the realities of the topology of the integrated system; these are the correct price signals that the ISO should establish. Prices and schedules established in the ISO's markets should reflect the redispatches necessary to clear the markets and produce feasible schedules that the ISO does through its security constrained economic dispatches and unit commitments.

D. Use of Transaction Identifiers for Intertie Resources Not Associated with Actual Physical Resources Will Enhance the ISO's Ability to Track Such Transactions

The ISO currently uses resource identifiers (resource IDs) for the purposes of tracking bids, resource information and other information utilized in the market clearing and settlement processes. Currently, resource IDs are used for the purposes of tracking non-resource specific transactions at the interties as well. This system is problematic as the resource ID system is designed and more appropriate for purposes of tracking specific resources. This poses a constraint because the system has to create multiple resource IDs for non-resource specific resources. In enhancing its modeling efforts, the ISO has determined that it is more appropriate to utilize a different transaction tracking system for non-resource specific transactions. Under the new system the ISO proposes to adopt, rather than assigning resource IDs to non-resource specific transactions, the ISO will instead assign a transaction identifier (transaction ID). The ISO will apply the transaction ID to any transaction that is not associated with an intertie resource registered in the master file, which is where the ISO stores all the physical characteristics utilized through the ISO market systems. Those include bids at the interties for system resources that are not dynamic, pseudo ties, or resource specific system resources, and virtual bids.[74]

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[73] *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 45 ("[W]hile we agree that the CAISO should operate the California grid using the most accurate model of internal and external areas that it can and direct the CAISO to work with external control areas to develop the model more fully in the future, we understand that the CAISO can only model external areas to the extent it has the information to do so.").

[74] System resources are resources located outside of the ISO balancing authority area that are capable of providing energy and ancillary services to the ISO balancing authority area. Tariff appendix A, definition of "system resource."

Each transaction ID will not be registered in the ISO's master file but will be generated when bids are submitted. Such transaction ID will persist through the ISO market systems, from bid validation through market clearing and settlements. The transaction ID will help the ISO to identify bids and schedules, enforce scheduling limits, and facilitate intertie schedule tagging of physical bids and intertie referencing for virtual bids, without the need to register an unbounded number of resources in the master file. Further, the use of a transaction ID as the main means to identify bids and schedules will require only minimal changes to market participants' existing systems because they can simply substitute the transaction ID for the resource ID in those existing systems.[75]

This will not affect dynamic resources that undertake dynamic transfers, which are transfers (imports and exports) of energy or ancillary services from such resources interconnected in one balancing authority area into another balancing authority area pursuant to a dynamic signal in the balancing authorities' energy management systems. Dynamic resources may participate in the day-ahead market as well as the 15-minute and 5-minute real-time markets. After the modeling enhancements go into effect, the ISO will continue to model dynamic resources at resource-specific locations as it does today. Each dynamic resource is registered with the ISO and assigned a unique resource ID registered in the ISO's master file.

Similarly, this will not affect bids from static (non-dynamic) resources that are certified to provide ancillary service imports or exports in the day-ahead market and/or the 15-minute real-time market, but cannot do so in the 5-minute real-time market. These static intertie bids will continue to be eligible for submission at the current scheduling points on the interties.[76]

Unlike dynamic resources, static intertie bids or schedules are not associated with a specific resource and are not required to have a resource ID registered in the master file. Therefore, the ISO proposes to implement the use of a new transaction ID that will serve as a surrogate resource ID to uniquely identify these bids and any resulting schedules for system resources.

However, for static intertie bids associated with resource adequacy

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[75] Draft final proposal at 24-25. The ISO proposes to define the new term "Transaction ID" in tariff appendix A consistent with the discussion above. The ISO also proposes to include the transaction ID as a component of energy bids and ancillary services bids for system resources. *See* revised tariff sections 30.5.2.1 and 30.5.2.4.

[76] Participants in the energy imbalance market and resources pursuant to a market efficiency enhancement agreement or an interchange scheduling agreement are subject to different modeling of imports and exports. Draft final proposal at 24.

capacity, existing transmission contracts, transmission ownership rights, ancillary services certification, or other contractual arrangements, as is the case today, it will still be necessary to set up a resource ID in the master file to link those bids to their contract information. For each resource registered in the master file, the transaction ID will be its resource ID.[77]

E. Incorporating the Modeling Enhancements into the Network Models Used for Allocation and Auction of Congestion Revenue Rights Will Ensure Feasible Entitlements

The ISO also proposes to incorporate the modeling enhancements that will be used in the operation of the day-ahead market into the development of the modeling assumptions and full network model for congestion revenue rights.

In implementing the enhancements, the ISO's goal is to maintain revenue adequacy in the congestion revenue right allocation and auction processes. To achieve that goal, the enhanced full network model for congestion revenue rights will track, to the extent possible, the enhanced full network model as utilized in the day-ahead market. In particular, the ISO will incorporate the schedules described above into the enhanced full network model for congestion revenue rights on a seasonal time-of-use or monthly time-of-use basis.[78] The ISO proposes to revise tariff section 36.4 to state that adjustments for possible unscheduled flow at the interties will be taken into consideration in determining the monthly available congestion revenue right capacity that is based on the direct current full network model.

The ISO will also continue to use the most up-to-date full network model when the ISO conducts its congestion revenue right allocations and auctions.[79] The ISO updates the full network model which it draws from the WECC network model at scheduled intervals throughout the year. The ISO then produces the full network model used in the allocation and auction of the congestion revenue rights (*i.e.*, the "CRR FNM") from the most recently created full network model the ISO has built at the time it conducts the allocations or auctions, which occur annually for seasonal congestion revenue rights and monthly for monthly congestion revenue rights. Therefore, once the ISO has updated the full network model with the expanded topology as discussed in Section III.C above, the congestion revenue right allocations and auctions that occur after that will also include the extended topology.

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77 *Id.* at 26.

78 *Id.* at 29. Pursuant to the further tariff revisions to be developed in the second stakeholder process on modeling enhancements, congestion revenue rights will be modeled at the new scheduling hubs. *Id.* at 50-53.

79 *See* tariff section 36.4.

A few stakeholders expressed concern that including flows from interconnected balancing authority areas will render currently held congestion revenue rights infeasible. The ISO expects previously released congestion revenue rights to remain feasible because the ISO conservatively released these rights only up to 75 percent of the system transmission capacity. If, despite this conservative approach, some small subset of the congestion revenue rights that are currently held by market participants turns out to be infeasible, the existing ISO tariff includes procedures to address such infeasibility.[80]

F. Miscellaneous Tariff Revisions

In addition to the tariff revisions discussed above, the ISO proposes miscellaneous revisions to its tariff to reflect the implementation of the real-time market design enhancements and to make minor clarifying changes.[81] The ISO is also submitting a table describing all of the tariff changes as attachment H to this filing, which reflects any ministerial changes it is making as well.

The ISO proposes to revise the definition of the term "Intertie" in tariff appendix A to mean a transmission corridor that interconnects the ISO balancing authority area with another balancing authority area. The revised definition will be more accurate and consistent with other tariff revisions reflecting the ISO's improved modeling.

IV. Additional Issues Raised by Stakeholders

There is broad support for the ISO's goal of enhancing the full network model and accurately modeling unscheduled flow in the day-ahead market. Stakeholders did raise concerns with certain aspects of the ISO's proposal, many of which were resolved in the extensive stakeholder process the ISO conducted. The ISO addressed several stakeholder concerns in the detailed discussion of its proposal above. The following discussion addresses some generic concerns raised by stakeholders, as well as some suggestions that are beyond the scope of the ISO's proposal.

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[80] Tariff sections 24.4.6.4, 36.4.1, 36.4.2, 36.8.7.1, 36.8.7.2. These existing provisions ensure full funding of the released congestion revenue right entitlements, which are funded through a revenue account that tracks any shortages and funds such shortages through charges to ISO demand.

[81] *See* revised tariff sections 6.5.10.1.4, 11.2, 27.1.2.2, 27.4, 27.4.3, 27.4.3.1, 27.4.3.5, 27.5.1.1, 30.5.2.6.2, 30.5.2.6.3, 31.8.1.

A. The ISO Will Analyze the Impacts of the Modeling Enhancements Before Implementing the Modeling of Unscheduled Flows and Enforcement of Physical Constraints

Some stakeholders requested additional analysis validating the ISO's proposed methodology. Specifically, the stakeholders expressed concern that the external load, generation, and interchange data at the time the day-ahead market is run will not reflect all the transactions that are finalized later in the day and therefore will not produce accurate results.

Such concerns are misplaced. While no methodology can guarantee perfect predictions, the ISO's methodology will provide the best possible estimate of unscheduled flow based on available external load, generation, and interchange data prior to running the day-ahead market. That data will also be validated.[82] It is true that some transactions may be finalized after the close of the day-ahead market, but the ISO's methodology will take into account trends in such transactions to project likely transactions. The alternative would be for the ISO to disregard the data now available on external system conditions and to develop no estimates of unscheduled flows in the day-ahead market. Such an alternative would prevent the ISO and its market participants from realizing the numerous reliability and market efficiency benefits of the ISO's proposal.

Also, based on stakeholder feedback, the ISO has committed to certain additional steps to alleviate the concerns raised by stakeholders. As discussed in the addendum to the draft final proposal, the ISO will analyze the results of the ISO's approach to estimating unscheduled flow on the interties, including the ISO's methodology for creating base schedules, and demonstrate its accuracy prior to implementing the modeling of unscheduled flows and enforcement of physical constraints in the day-ahead market. This analysis will be conducted in the summer of 2014 once the ISO receives software code from its vendors.[83]

Specifically, the analysis will be a power flow-based modeling assessment that will use the methodologies described generally below, as applied to market data for actual days prior to implementation to show the differences between the ISO's current modeling approach and the proposed modeling enhancements. The metric the ISO will use to measure whether the modeling enhancements are functioning as intended will be a comparison between day-ahead modeled and

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[82] See Section III.A above.

[83] This analysis will not be focused on the study the expansion of the ISO's full network model, which consists of more detailed modeling of the topology and sources and sinks on the external system. Rather, the analysis is focused on evaluating the ISO's ability to model unscheduled flow at the interties, which is a distinct and separate modeling enhancement proposed herein. As such, the expanded topology can be implemented on September 8 2014, before the report of this analysis will be finalized.

actual unscheduled flows. The modeling assessment will make that comparison for a set of representative days for four interties: (1) California-Oregon Intertie, (2) Palo Verde, (3) Eldorado-Mead, and (4) Victorville-Lugo.[84] ISO management will provide the results in a briefing to the ISO Board.

The ISO has provided stakeholders with a detailed plan for this pre-implementation analysis. The milestones in the pre-implementation plan will include:

- In May, start to compile the data and establish processes necessary for the pre-implementation analysis;

- Initiate power flow-based analysis when the ISO has stabilized the new software code on its systems (coincides with the start of market simulation on or about July 8, 2014);

- Rerunning of historical market runs through mid- to late-August 2014;

- ISO reporting of the results of the pre-implementation analysis to stakeholders and to the Board at its September 18-19, 2014 meeting.[85]

The ISO commits to submit the results of its analysis to the Commission for informational purposes after its analysis is presented to the Board at the September 18-19, 2014 Board meeting and prior to the October 1 go-live date for implementing the modeling of unscheduled flow and enforcement of power flow constraints in the day-ahead market.[86] The Market Surveillance Committee agrees with the ISO's proposal to perform a modeling assessment before the modeling enhancements are implemented and to put ongoing benchmarking metrics into effect.[87]

There is no need to make the acceptance of the proposed tariff revisions contingent on the results of the pre-implementation analysis, because the ISO's requested authority includes the discretion to make adjustments to certain implementation details (that will be reflected in the business practice manual) where justified by this analysis. Specifically, proposed tariff section 31.8.2

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[84] Addendum to draft final proposal at 1-3.

[85] Board memorandum at 5; draft final proposal at 38-39; addendum to draft final proposal at 2-3.

[86] As discussed above, the ISO requests authority to implement the expanded full network model topology on September 8, 2014, *i.e.*, prior to the October 1, 2014 date on which the ISO proposes to implement the modeling enhancements described in Sections III.A and III.B above.

[87] MSC opinion at 9-10.

provides that the ISO:

> may enforce a physical flow constraint limit at each internal and Intertie location in the IFM taking into account the total power flow contributions, which include internal schedules and import/export schedules, which can be physical or virtual, and the CAISO's estimates of unscheduled flow at the Interties.

Under the ISO's proposal, the ISO will have the flexibility to make adjustments to net scheduled interchange(s) and/or schedule(s) as the situation requires. Therefore, the ISO will be able to make needed adjustments if the external load, generation, and interchange data at the time the day-ahead market is run do not reflect all the transactions that are finalized later in the day. As noted above, the ISO's discretion includes the ability to fine-tune demand forecasts based on a historical analysis of actual demand and to adjust net scheduled interchanges and/or entire schedules.

After the implementation of the modeling enhancements, the ISO will track ongoing benchmarking metrics including: (1) comparison of day-ahead and real-time market flows versus actual flows, (2) analysis of compensating injections in the real-time, and (3) tracking of real-time congestion offset uplift costs. These ongoing metrics will enable market participants to evaluate the performance of the modeling enhancements and will help the ISO to improve modeling for the reliable, efficient operation of its markets.[88] The ISO's proposal also contains a number of safeguards to prevent inappropriate results.

As discussed above, the ISO's approach to the modeling of unscheduled flow at the interties permits the ISO to avoid modeling the unscheduled flow by simply not including the base schedules in the day-ahead market and setting the net-interchange schedules to zero in the affected external balancing authority areas. As explained above, the ISO needs this flexibility in order to deal with the possibility that it might receive unreliable data and therefore would be unable to use the data in operating the markets. Thus, should the analysis uncover the need for further refinements of the base schedule approach, the ISO will take such steps until it is confident that it can model unscheduled flow at the interties reliably.

Similarly, if the ISO receives inaccurate or inconsistent data it may not be appropriate to enforce power flow constraints in the day-ahead market. Again, the ISO's proposal includes an appropriate "safety valve" that allows the ISO to assess the accuracy of input data and not enforce the power flow constraints if there is a problem.

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[88] Draft final proposal at 39.

Market participants will have full visibility on what unscheduled flows that are modeled through the data the ISO proposes to provide to participants stipulated in proposed section 6.5.10.1.5. Through this data, parties can also see how well the ISO is modeling unscheduled flows.

Therefore, despite the ISO's commitment to undertake the additional analysis described above, the Commission can safely approve the ISO's proposal without creating the risk that the ISO will be forced to use inaccurate information in modeling the unscheduled flow or enforcing the power flow constraints.

B. The Proposed Modeling Enhancements Are Expected to Provide Overall Market Efficiency Benefits

As noted above, the modeling enhancements proposed in this filing would be justified on reliability grounds alone and are appropriate to address the recommendations of Commission and NERC staff following the September 8, 2011, outage event. A number of stakeholders, however, raised concerns that the improved modeling of external balancing authority areas in the day-ahead timeframe could cause day-ahead market prices to increase. These concerns disregard the overall market efficiency benefits which are expected from the modeling enhancements.

As shown in the discussion and examples provided in Section II.C.2, the ISO's existing day-ahead market processes ignore unscheduled flow. Having the market run with such blinders on in the day-ahead causes the ISO to have to account for unscheduled flow in real-time when the cost of resources often is higher and when the ISO may be required to rely on non-market mechanisms such as exceptional dispatch to address the system needs created by unscheduled flow. This results in increased real-time congestion offset uplift costs.

Now, however, data are available to model such unscheduled flow. Modeling loop flow in the day-ahead market will provide efficiency benefits even if the best day-ahead information on anticipated unscheduled flow is not a perfect predictor of actual unscheduled flow in real-time. It is preferable for the ISO to attempt to do something to better address unscheduled flow in the day-ahead, and address any remaining unscheduled flow issue in the real-time to the extent the day-ahead solution did not fully resolve unscheduled flow, than to simply bury its head in the sand and ignore system issues likely to result in unscheduled flow until the real-time. As the Market Surveillance Committee notes:

> Forecasts are rarely perfect. Some market participants have predicted that it will be harder to accurately project loopflows in the WECC than in the eastern interconnection, for example due to

> difficulties in predicting hydro operations. It is possible that this will turn out to be the case. But the issue is not whether the CAISO's loopflow projections will always be perfect but whether they will be more accurate, on average, than no forecast at all.[89]

The ISO believes that the loop flow projections to be used in the day-ahead market as a result of the modeling enhancements will be more accurate than no loop flow forecast at all. As the Market Surveillance Committee explains, loop flows are "predictable to some degree" and the enhancements "will provide another incremental improvement in the modeling of loopflows that impact transmission constraints on the CAISO grid."[90]

The fact that unscheduled flow is not accounted for in the full network model used in today's day-ahead market, but is addressed in the real-time, creates an arbitrage possibility that exists solely because of the current limitations in day-ahead modeling. In other words, differences between day-ahead and real-time modeling result in differences between day-ahead and real-time market prices that convergence bidders can exploit. The proposed modeling enhancements will eliminate or reduce such arbitrage possibilities. The Market Surveillance Committee supports this goal of the proposed enhancements.[91]

Some stakeholders questioned why the ISO and its market participants should address unscheduled flow from other parts of the West before the rest of the region takes steps to address unscheduled flow issues. The ISO is uniquely positioned as the only organized market in the western United States and must take measures to ensure that its modeling creates feasible schedules that support both the reliable operation of the ISO controlled grid and efficient operation of the ISO markets. The modeling enhancements will benefit ISO market participants by providing them better day-ahead pricing and more transparent market information.

This does not mean, however, that the ISO will disregard efforts to address unscheduled flow issues in other parts of the West. The ISO is active in regional coordination efforts. The enhanced modeling will take advantage of WECC's unscheduled flow mitigation procedure as it applies to the California Oregon Intertie. It is also important to recognize that the ISO markets already are impacted by unscheduled flow. Accordingly, it would be imprudent for the ISO to delay making modeling improvements to its own markets until the rest of

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89 MSC opinion at 10.

90 *Id.* at 10 & n.19.

91 *Id.* at 14-15.

the region takes similar steps.

Moreover, the modeling enhancements will not cause any issues related to transmission use and expansion. In response to stakeholder concerns, the Market Surveillance Committee stated that it did not believe the enhancements will result in the ISO choosing to forgo use of the transmission system paid for by ISO transmission customers in order to accommodate use of the ISO transmission system by external balancing authority areas.[92] Further, the Market Surveillance Committee was unable to identify any adverse impact on transmission expansion incentives from any element of the enhancements.[93]

C. The ISO's Proposal Is Not Inconsistent with Commission Orders Concerning the Use of Transmission Reliability Margin to Accommodate Unscheduled Flow

One stakeholder suggests that the ISO's proposal is inconsistent with the approach for addressing loop flow set forth in Order No. 890. The stakeholder suggested that Order No. 890[94] expressly directs the use of transmission reliability margin ("TRM") to accommodate unscheduled flow and requires the coordination of available transmission capacity ("ATC") calculations among adjacent transmission providers. Order No. 890 does not mandate the use of TRM to account for loop flow. Instead, the Commission has simply indicated that transmission providers **may** set aside transmission reliability margin to account for loop flow impacts:

> Transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process.[95]

The ISO has been willing to apply transmission reliability set asides where justified. In 2012, the Commission accepted a voluntary ISO proposal to amend

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[92] *Id.* at 7.

[93] *Id.* at 15-16.

[94] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[95] Order No. 890 at P 273.

its tariff to allow it to use transmission reliability margin values in real-time to address the following three conditions: (1) forecast uncertainty in transmission system topology (including but, not limited to, forced or unplanned outages and maintenance outages); (2) allowances for parallel path (loop flow) impacts; and (3) allowances for simultaneous path interactions.[96]

It is important to remember that transmission reliability margin is a scheduling tool, not a tool designed for modeling physical flows. Therefore, the ISO does not believe transmission reliability margin is appropriate to address unscheduled flows resulting from day-ahead system conditions in the West.

Based on its consideration of the best way to respond to recommendations of the April 2012 report, the ISO has concluded that calculating the unscheduled flow from base schedules in the rest of the West is a more systematic, comprehensive, and effective approach to account for day-ahead system conditions in the West. First, given the complexity of calculating flows through the Western Interconnection, modeling the base schedules will mean modeling interactions that will, at some basic level, occur every day, unlike events that cause forced outages. For example, a demand forecast for one balancing authority area may be 10,000 MW, but actual demand was 10,200 MW. While the forecast accuracy can be improved, it is more reasonable to assume the balancing authority area has 10,000 MW of demand rather than zero. Second, the transmission reliability margin procedure would only apply to interties, but the intent of the unscheduled flow calculation is to understand the impact of such flows for the entire ISO market, including internal transactions. Lastly, modeling unscheduled flow may lead to redispatch that does not result in any impact on the ATC (*i.e.*, the scheduling limit). The ISO believes its proposed approach provides greater consistency.

This stakeholder suggests that the ISO is pursuing (1) a physical limit approach on interties that departs from regional ATC practices and (2) pricing of external awards based on physical flow in a manner inconsistent with contract-based scheduling in the West. These claims are incorrect. Consistent with the objective of ongoing regional coordination, the ISO's proposal retains the use of scheduling limits at the interties even though the ISO's internal market is flow-based. The ISO intends to continue its practice of coordinating ATC with neighboring regions and providing this information on the ISO's OASIS.[97] The physical flow constraint is separate from the ATC calculation and reflects actual congestion when it is binding. It is also incorrect to suggest that the ISO should

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[96] *See* June 5, 2012, Commission letter order in Docket No. ER12-1468.

[97] The ISO notes that Commission precedent does not impose a "one-size-fits-all" approach to ATC calculation, but instead allows variations in ATC calculation methodology as long as such variations are shown to be just and reasonable.

be required to price transactions in a manner consistent with contract-based scheduling. The ISO's Commission-approved tariff has never been based on contract-based scheduling or the *pro forma* open access transmission tariff.

This stakeholder also argued that the ISO should require that recipients of awards that clear the ISO's day-ahead market submit e-tags for those awards. As the Commission has recognized in a recent order rejecting this same stakeholder's arguments for a day-ahead e-tagging requirement, day-ahead e-tagging is not mandatory in the West:

> as stated in both the WECC and WSPP master agreements, day-ahead e-tagging, while perhaps customary, is not required for all contracts in the West. Counterparties to these contracts, and not CAISO, are in the best position to manage financial risks associated with the receipt of day-ahead e-tags.[98]

D. No Changes Should Be Made to the Current Methodology for Allocating Real-Time Congestion Offset Uplift

Several stakeholders requested that, in connection with the modeling enhancements, the ISO should revise the current methodology for allocating real-time congestion offset uplift based on cost causation principles. Such proposal is not only far beyond the scope of the ISO's proposed tariff amendments, and hence the subject matter of this proceeding, it also is not justified. There is nothing in the ISO's proposal that causes the existing cost allocation methodology for real-time congestion offset to become unjust and unreasonable. Indeed, as explained above, the modeling enhancements merely seek to enforce physical flow constraints on the interties in the day-ahead so that they are consistent with enforcement of those constraints in the real-time. The ISO's proposal will improve the ISO's modeling of unscheduled flow in the day-ahead market, addressing one of the underlying causes of real-time congestion offset and thus reducing the amount of real-time congestion offset uplift that must be allocated. As such, this request is unnecessary and beyond the scope of this proceeding.

Even if a change to the cost allocation methodology for real-time congestion offset were justified, it would be premature to make such a change now. One of the root causes of real-time congestion offset uplift is the lack of unscheduled flow modeling in the day-ahead market. To the extent a change is considered through the ISO's stakeholder process, the ISO believes it is important to assess the impact of the proposed modeling enhancements on such costs and to use the data collected from the enhanced full network model efforts, at a minimum, to inform any future change to the cost allocation for this

98 *California Independent System Operator Corp.*, 146 FERC ¶ 61,204, at P 102.

uplift charge.[99]

V. Effective Dates and Request for Waiver

The ISO respectfully requests that the Commission issue an order by July 31, 2014, that (1) accepts the proposed revisions to tariff sections 11.2, 27.5.1.1, 30.5.2.1, and 30.5.2.4, and the new defined term "Transaction ID," effective September 8, 2014, and (2) accepts the balance of the tariff revisions contained in this filing effective October 1, 2014. The ISO requests waiver of the Commission's notice requirement to permit the requested October 1 effective date.[100]

As discussed above, the revisions to tariff section 27.5.1.1 concern improvements to the base network model used in the ISO markets. The ISO intends to implement these improvements in September 2014 so that the ISO will have sufficient time to integrate the new model into its markets prior to the October 1, 2014, *i.e.,* the release date of new functionality, including the energy imbalance market, which relies on the extended topology of the base market model. Granting the requested September 8, 2014, effective date for those revisions will facilitate the ISO's implementation of the rest of the tariff revisions effective October 1.

An effective date of October 1 for the remaining tariff revisions is appropriate to ensure that the schedule for implementing the proposed modeling enhancements aligns with the schedule for implementing the ISO's new energy imbalance market. As noted above, the extension of the topology of the base market model is necessary to support the extended energy imbalance market. This will be beneficial for accurately modeling the balancing authority areas that will participate in the energy imbalance market.

The modeling of unscheduled flow and enforcement of flow-based constraints in the day-ahead market will also contribute to the accuracy of the energy imbalance market solutions. While the ISO can proceed with the energy imbalance market without these two modeling enhancements, they would significantly enhance the quality of the energy imbalance market solution. As such, the modeling enhancements as a whole reflect an important complement to the energy imbalance market that will significantly improve the quality of market solutions. Delaying the proposed modeling enhancements could result in less

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[99] Board memorandum at 6.

[100] Specifically, pursuant to section 35.11 of the Commissions regulations (18 C.F.R. § 35.11), the ISO requests waiver of the notice requirement contained in section 35.3 of the Commission's regulations (18 C.F.R. § 35.3) to allow the requested effective date.

accurate dispatch and pricing as to those balancing authority areas once the energy imbalance market is implemented.

The ISO has two major releases per year for new market functionality. This allows the ISO to manage numerous changes to its processes and software in a streamlined and controlled manner. By scheduling two predictable and staged releases, the ISO can support a larger volume of enhancements, while minimizing both technical and financial impacts to the ISO and its market participants. The fall market release, which includes the new energy imbalance market, is scheduled for October 1. As discussed in Section II.C.4 above, as of October 1 the modeling enhancements will include the detailed modeling of PacifiCorp East and PacifiCorp West, which are the two balancing authority areas that will begin to take part in the energy imbalance market on that date; detailed modeling of Bonneville Power Administration and Idaho Power Company, through which PacifiCorp has contractual rights that it will make available to the energy imbalance market; detailed modeling of Bonneville Power Administration and Idaho Power Company, through which PacifiCorp has contractual rights that it will make available to the energy imbalance market; detailed modeling of other balancing authority areas in the Pacific Northwest that are highly interconnected with Bonneville Power Administration and Idaho Power Company; and use of a common network model in the ISO's markets and energy management system for balancing authority areas that contain parallel paths between the ISO's and PacifiCorp's balancing authority areas. The Commission's acceptance of the energy imbalance market tariff revisions in Docket No. ER14-1386 will allow the ISO to model these balancing authority areas consistent with its existing tariff authority to model external balancing authority areas, and the tariff revisions proposed in this filing will allow the ISO to make the best use of recently available data on these balancing authority areas to enhance its ability to operate the system reliably.

The ISO requests that the Commission issue an order by July 31, 2014 accepting the proposed tariff revisions in order to allow the ISO to perform the testing and make the system changes required to implement the modeling enhancements by October 1. Prior to implementing the modeling enhancements, the ISO must complete testing, staging, and production of the market software. First, the ISO and its market participants must evaluate the impact of the Commission's order prior to starting the code promotion to its stage environment to orchestrate the promotion and communicate its plans to market participants so that they too can prepare for the transition. The ISO must then promote the software to the stage environment to perform the final performance testing. The ISO's testing phase will evaluate the completeness and quality of the delivered software solution. The testing will include functional testing of software to determine if the software product meets the business and system requirements identified by the ISO during the requirements and design phases, as well as how the software performs with the integration of downstream applications, including the ISO's settlement system. This level of testing is standard practice when deploying new software code or changes in any software code. Financial risks to market participants and the potential for issues with overall market solution quality caused by insufficient testing of the software are not acceptable outcomes from a software deployment perspective. Issuance of an order by July 31 will allow the ISO to complete all of these steps as well as to conduct the pre-implementation analysis described above.

For these reasons, the Commission should find that good cause exists for the Commission to grant waiver and permit the requested effective date of October 1, 2014 for the proposed tariff revisions other than the revisions to tariff sections 11.2, 27.5.1.1, 30.5.2.1, and 30.5.2.4, and the new defined term "Transaction ID," to reflect improvements in the ISO's base market model, for which the ISO requests a September 8, 2014, effective date.

VI. Communications

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VII. Service

The ISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the ISO tariff. In addition, the ISO has posted a copy of the filing on the ISO website.

VIII. Contents of this Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean ISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Draft final proposal
Attachment D	Addendum to draft final proposal
Attachment E	Market Surveillance Committee opinion
Attachment F	Board memorandum
Attachment G	List of key dates in the stakeholder process
Attachment H	Table of proposed tariff revisions

IX. Conclusion

For the reasons set forth in this filing, the ISO respectfully requests that the Commission issue an order by July 31, 2014, that accepts the proposed revisions to tariff sections 11.2, 27.5.1.1, 30.5.2.1, and 30.5.2.4, and the new defined term "Transaction ID," to reflect improvements in the ISO's base market model effective September 8, 2014, and that accepts the balance of the tariff revisions contained in this filing effective October 1, 2014.

Respectfully submitted,

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Attachment A – Clean Tariff Sheets

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

6.5.10 Protected Communications with Market Participants

6.5.10.1 Protected Data

The CAISO will provide to parties that have signed a Non-Disclosure Agreement in accordance with Section 6.5.10, the following Protected Data:

6.5.10.1.1 Transmission Constraints Enforcement List

After the results of the Day-Ahead Market are posted, the CAISO will provide the daily post-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the list of Transmission Constraints, including Contingencies and Nomograms that are enforced and not enforced in that day's Day-Ahead Market. Subsequently and prior to the next Day-Ahead Market, the CAISO will provide to parties the pre-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the daily list of information for the Transmission Constraints, including Contingencies and Nomograms, the CAISO plans to enforce or not enforce for the next day's Day-Ahead Market. To the extent that the CAISO does not make either of these two reports available on any given Operating Day, the CAISO will instead provide within the next thirty (30) days only the list of Transmission Constraints, including Contingencies and Nomograms, that were enforced or not enforced for the applicable Day-Ahead Market, after which the information will not be provided.

6.5.10.1.2 Load Distribution Factors

Three (3) days after the applicable Trading Day, the CAISO will provide the actual Load Distribution Factors used in the Integrated Forward Market for the applicable Trading Day. The CAISO will provide the Load Distribution Factors for each of the Default LAPs' underlying Pricing Nodes for all Pricing Nodes that are identified by the responsible Utility Distribution Company as Pricing Nodes at which there is more than just a single customer. For Pricing Nodes that the responsible Utility Distribution Company has not identified as Pricing Nodes at which there is more than just a single customer, the ISO will publish the respective Load Distribution Factors in a single aggregated location capturing all such nodes. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report within the next thirty (30) days for the applicable Integrated Forward Market, after which the information will not be provided.

6.5.10.1.3 Power Transfer Distribution Factors

Three (3) days after the applicable Trading Day, the CAISO will provide the Integrated Forward Market, HASP and Real-Time Dispatch Power Transfer Distribution Factors for each binding Transmission Constraint in the respective markets. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report for any given successful Integrated Forward Market, HASP and Real-Time Dispatch run within the next thirty (30) days, after which the information will not be provided.

6.5.10.1.4 Transmission Constraints Limits

6.5.10.1.4 Transmission Constraints Limits

Three (3) days after the applicable Trading Day, the CAISO will provide a report on the limits associated with all Transmission Constraints, including Nomograms, branch groups, and individual transmission facilities, under both base case and contingencies, that are enforced in the Integrated Forward Market, FMM and Real-Time Dispatch, and that based on the flows in the respective market runs are approaching the limits. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report within the next thirty (30) days for any given successful Integrated Forward Market, FMM and Real-Time Dispatch run, after which the information will not be provided.

6.5.10.1.5 Unscheduled Flow Estimates

After the results of the Day-Ahead Market are posted, the CAISO will provide the hourly unscheduled flow at each Intertie considered in the Day-Ahead Market. After the results of the Real-Time Market are posted, the CAISO will provide the unscheduled flow at each Intertie considered in the Real-Time Market. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report within the next thirty (30) days for the applicable Day-Ahead Market and Real-Time Market, after which the information will not be provided.

6.5.10.2 Requirements to Obtain the Protected Data

The CAISO shall provide the Protected Data only to those Market Participants and non-Market

Participants that satisfy the following requirements.

(a) To obtain access to the Protected Data, a Market Participant that is a member of the WECC that requests the Protected Data must: (i) execute and submit to the CAISO the Non-Disclosure Agreement for Protected Data that is posted on the CAISO Website; and (ii) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the Market Participant, executed by each employee and consultant of the Market Participant who will have access to the Protected Data.

(b) To obtain access to the Protected Data, a Market Participant that is not a member of the WECC that requests the Protected Data must: (i) execute and submit to the CAISO the Non-Disclosure Agreement for Protected Data that is posted on the CAISO Website, (ii) provide to the CAISO a fully executed WECC Non-Member Confidentiality Agreement for WECC Data, and (iii) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the non-WECC Market Participant, executed by each employee and consultant of the non-WECC Market Participant who will have access to the Protected Data.

(c) To obtain access to the Protected Data a non-Market Participant that is a member of the WECC that requests the Protected Data must: (i) reasonably demonstrate a legitimate business or governmental interest in the CAISO Markets, (ii) execute the Non-Disclosure Agreement for Protected Data posted on the CAISO Website, and (iii) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the non-Market Participant, executed by each employee and consultant of the non-Market Participant who will have access to the Protected Data.

(d) To obtain access to the Protected Data , a non-Market Participant that is not a member of the WECC that requests the Protected Data must: (i) reasonably demonstrate a legitimate business or governmental interest in the CAISO Markets, (ii) execute the Non-Disclosure Agreement for Protected Data that is posted on the CAISO Website, (iii) provide to the CAISO a fully executed WECC Non-Member Confidentiality Agreement for WECC Data, and (iv) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the non-Market Participant, executed by each employee and consultant of the non-Market Participant who will have access to the Protected Data.

6.5.10.3 Obligation to Report Violations of Section 6.5.10

Each Market Participant, non-Market Participant, employee of a Market Participant, employee of a non-Market Participant, consultant, and employee of a consultant to whom the CAISO distributes the Protected Data shall be obligated to immediately report to the CAISO any violation of the requirements of Section 6.5.10.

11.2 Settlement Of Day-Ahead Market Transactions

All transactions in the IFM and RUC as specified in the Day-Ahead Schedule, AS Awards and RUC Awards, respectively, are financially binding and will be settled based on the Day-Ahead LMP, ASMP or RUC Price for the relevant Location for the specific resource or transaction identified for the Bid. The CAISO will settle the costs of Demand, capacity, Energy and Ancillary Services as separate Settlement charges and payments for each Settlement Period of the Day-Ahead Schedule, Day-Ahead AS Award or RUC Award, as appropriate.

27.1.2 Ancillary Service Prices

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM and the FMM, and the CAISO also accepts and awards HASP Block Intertie Schedules for Ancillary Services in HASP. Ancillary Services awarded through HASP are made financially binding in the FMM. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO accepts and awards Ancillary Services from HASP Block Intertie Schedules for the next Trading Hour as described in Section 34.2. The CAISO calculates the price for the settlement of Ancillary Services accepted and awarded in HASP based on the FMM ASMP as described herein and further described in Section 34.4. The FMM process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

27.1.2.2 Opportunity Cost in ASMP

The Ancillary Services Shadow Price, which, as described above, is a result of the Energy and Ancillary Service co-optimization, includes the foregone opportunity cost of the marginal resource, if any, for not providing Energy or other types of Ancillary Services the marginal resource is capable of providing in the relevant market. The ASMPs determined by the IFM or FMM optimization process for each resource whose Ancillary Service Bid is accepted will be no lower than the sum of (i) the Ancillary Service capacity Bid price submitted for that resource, and (ii) the foregone opportunity cost of Energy in the IFM or FMM for that resource. The foregone opportunity cost of Energy for this purpose is measured as the positive difference between the IFM or FMM LMP at the resource's Pricing Node and the resource's Energy Bid price. If the resource's Energy Bid price is higher than the LMP, the opportunity cost measured for this calculation is $0. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is under an obligation to offer Energy in the Day-Ahead Market (e.g. a non-hydro Resource Adequacy Resource), its Default Energy Bid will be used, and its opportunity cost will be calculated accordingly. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is not under an obligation to offer Energy in the Day-Ahead Market, its Energy opportunity cost measured for this calculation is $0 since it cannot be dispatched for Energy. For Self-Scheduled Hourly Block Bids for Ancillary Services awarded in the Real-Time Market, the opportunity cost measured for this purpose is $0 because, as provided in Section 34.2.3**,** the CAISO cannot Schedule Energy in the Real-Time Market from the Energy Bid under the same Resource ID as the submitted Ancillary Service Bid.

27.1.2.3 Ancillary Services Pricing – Insufficient Supply

The CAISO will develop Scarcity Reserve Demand Curves as further described in an applicable Business Practice Manual that will apply to both the Day-Ahead Market and the Real-Time Market during periods in which supply is insufficient to meet the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up as required by Section 8.3. During the first three (3) years in which the CAISO's Scarcity Reserve Demand Curves are effective, the CAISO shall conduct an annual review of the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary, with the exception that the ISO will not conduct this assessment in any year in which the Scarcity Reserve Demand Curves are not triggered. Thereafter, the CAISO shall review the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary every three (3) years or more frequently, if the CAISO determines more frequent reviews are appropriate. When supply is insufficient to meet any of the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up, the Scarcity Reserve Demand Curve Values for the affected Ancillary Services, as set forth in this Section 27.1.2.3 and as reflected in the in the Scarcity Demand Curve Value table below, shall apply to determine the Shadow Prices of the affected Ancillary Services. ASMPs for an Ancillary Service type will not sum these Shadow Prices across Ancillary Service Regions, if there is insufficient supply for the Ancillary Service type in both the Expanded System Region and an Ancillary Service Sub-Region.

Reserve	**Scarcity Demand Curve Value ($/MWh)**					
	Percent of Energy Max Bid Price		**Max Energy Bid Price = $750/MWh**		**Max Energy Bid Price = $1000/MWh**	
	Expanded System Region	**System Region and Sub-Region**	**Expanded System Region**	**System Region and Sub-Region**	**Expanded System Region**	**System Region and Sub-Region**

Regulation Up	20%	20%	$150	$150	$200	$200
Spinning	10%	10%	$75	$75	$100	$100
Non-Spinning						
Shortage > 210 MW	70%	70%	$525	$525	$700	$700
Shortage > 70 & ≤ 210 MW	60%	60%	$450	$450	$600	$600
Shortage ≤ 70 MW	50%	50%	$375	$375	$500	$500
Upward Sum	**100%**	**100%**	**$750**	**$750**	**$1000**	**$1000**
Regulation Down						
Shortage > 84 MW	70%	70%	$525	$525	$700	$700
Shortage > 32 & ≤ 84 MW	60%	60%	$450	$450	$600	$600
Shortage ≤ 32 MW	50%	50%	$375	$375	$500	$500

27.1.2.3.1 Regulation Down Pricing – Insufficient Supply

When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be fifty (50) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is less than or equal to eighty-four (84) MW but greater than thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be sixty (60) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is greater than eighty-four (84) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be seventy (70) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.2 Non-Spinning Reserve Pricing – Insufficient Supply

When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be fifty (50) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is less than or equal to two-hundred ten (210) MW but greater than seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be sixty (60) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is greater than two-hundred ten (210) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be seventy (70) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.3 Spinning Reserve Pricing – Insufficient Supply

The Scarcity Reserve Demand Curve Value for Spinning Reserve in the Expanded System Region or in an Ancillary Service Sub-Region shall be ten (10) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.4 Regulation Up Pricing – Insufficient Supply

The Scarcity Reserve Demand Curve Value for Regulation Up in the Expanded System Region or in an Ancillary Service Sub-Region shall be twenty (20) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.4 Opportunity Cost in LMPs for Energy

In the event that there is insufficient supply to meet an Ancillary Services procurement requirement in a particular Ancillary Service Region or Sub-Region, the Ancillary Services Shadow Prices will rise automatically to the Scarcity Reserve Demand Curve Values in that

Ancillary Service Region or Sub-Region. LMPs for Energy will reflect the forgone opportunity cost of the marginal resource, if any, for not providing the scarce Ancillary Services consistent with the CAISO's co-optimization design.

27.4 Optimization In The CAISO Markets Processes

The CAISO runs the Day-Ahead Market and Real-Time Market and their component CAISO Markets Processes utilizing a set of integrated optimization programs, including SCUC and SCED.

27.4.3 CAISO Markets Scheduling And Pricing Parameters

The SCUC and SCED optimization software for the CAISO Markets utilize a set of configurable scheduling and pricing parameters to enable the software to reach a feasible solution and set appropriate prices in instances where Effective Economic Bids are not sufficient to allow a feasible solution. The scheduling parameters specify the criteria for the software to adjust Non-priced Quantities when such adjustment is necessary to reach a feasible solution. The scheduling parameters are configured so that the SCUC and SCED software will utilize Effective Economic Bids as far as possible to reach a feasible solution, and will skip Ineffective Economic Bids and perform adjustments to Non-priced Quantities pursuant to the scheduling priorities for Self-Schedules specified in Sections 31.4 and 34.10. The scheduling parameters utilized for relaxation of enforced internal and Intertie Transmission Constraints are specified in Section 27.4.3.1. The pricing parameters specify the criteria for establishing market prices in instances where one or more Non-priced Quantities are adjusted by the Market Clearing software. The pricing parameters are specified in Sections 27.1.2.3, 27.4.3.2, 27.4.3.3 and 27.4.3.4. The complete set of scheduling and pricing parameters used in all CAISO Markets is maintained in the Business Practice Manuals.

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an enforced internal and Intertie Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5,000 per MWh or less for the IFM (or $1,500 per MWh or less for the RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5,000 per MWh in the IFM (or $1,500 per MWh for the RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1,250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

27.4.3.3 Insufficient Supply to Meet Self-Scheduled Demand in IFM

In the IFM, when available supply is insufficient to meet all self-scheduled Demand, self-scheduled Demand is reduced to the point where the available supply is sufficient to clear the market. For price-setting purposes in such cases, the cleared self-scheduled Demand is deemed to be willing to pay the maximum Energy Bid price specified in Section 39.6.1.1.

27.4.3.4 Insufficient Supply to Meet CAISO Forecast of CAISO Demand in the RTM

In the RTM, in the event that Energy offers are insufficient to meet the CAISO Forecast of CAISO Demand, the SCUC and SCED software will relax the system energy-balance constraint. In such cases the software utilizes a pricing parameter set to the maximum Energy Bid price specified in Section 39.6.1.1 for price-setting purposes.

27.4.3.5 Protection of TOR, ETC and Converted Rights Self-Schedules in the IFM

In accordance with the submitted and accepted TRTC Instructions, valid Day-Ahead TOR Self-Schedules, Day-Ahead ETC Self-Schedules and Day-Ahead Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. The scheduling parameters associated with the TOR, ETC, or Converted Rights Self-Schedules will be set to values higher than the scheduling parameter associated with relaxation of an enforced internal and Intertie Transmission Constraint as specified in Section 27.4.3.1, so that when there is a congested Transmission Constraint that would otherwise subject a Supply or Demand resource submitted in a valid and balanced ETC, TOR or Converted Rights Self-Schedule to adjustment in the IFM, the IFM software will relax the Transmission Constraint rather than curtail the TOR, ETC, or Converted Rights Self-Schedule. This priority will be adhered to by the operation of the IFM Market Clearing software, and if necessary, by adjustment of Schedules after the IFM has been executed and the results have been reviewed by the CAISO operators.

27.4.3.6 Effectiveness Threshold

The CAISO Markets software includes a lower effectiveness threshold setting which governs whether the software will consider a bid "effective" for managing congestion on a congested Transmission Constraint. The CAISO will set this threshold at two (2) percent.

27.5.1 Network Models used in CAISO Markets

The FNM is a representation of the WECC network model including the CAISO Balancing Authority Area that enables the CAISO to produce a Base Market Model that the CAISO then uses as the basis for formulating the individual market models used to conduct power flow analyses to manage Transmission Constraints for the optimization of each of the CAISO Markets.

27.5.1.1 Base Market Model used in the CAISO Markets

Based on the FNM the CAISO creates the Base Market Model, which is used as the basis for formulating, as described in section 27.5.6, the individual market models used in each of the CAISO Markets to establish, enforce, and manage the enforced internal and Intertie Transmission Constraints associated with network facilities. The Base Market Model is derived from the FNM by (1) introducing locations for modeling Intertie Schedules; and (2) introducing market resources that do not currently exist in the FNM due to their size and lack of visibility. In the Base Market Model, external Balancing Authority Areas and external transmission systems are modeled to the extent necessary to 1) improve the accuracy of the CAISO Market solutions for purposes of reliable operations, and 2) support the commercial requirements of the CAISO Markets. For those portions of the FNM that are external to the CAISO Balancing Authority Area, the Base Market Model may model the resistive component for accurate modeling of Transmission Losses, but accounts for losses in the external portions of the market model separately from Transmission Losses within the CAISO Balancing Authority Area. As a result, the Marginal Cost of Losses in the LMPs is not affected by external losses. For portions of the Base Market Model that are external to the CAISO Balancing Authority Area, the CAISO Markets only enforce Transmission Constraints that reflect limitations of the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating Transmission Owner, or that affect Congestion Management within the CAISO Balancing Authority Area or on Interties. External connections are retained between Intertie branches within Transmission Interfaces. Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. The CAISO Markets' optimizations also factor in forecasted unscheduled flow at the Interties consistent with the requirements specified in the Business Practice Manuals. Resources are modeled at the appropriate network Nodes. The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Unit is connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid. Based on the Base Market Model, the market models used in each of the CAISO Markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, FMM Schedules, Dispatch Instructions, and LMPs resulting from each CAISO Markets Process. The Dispatch, Schedule, and LMP of a Dynamic System Resource or Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area refer to a PNode, or Aggregated Pricing Node, if applicable, of the resource at its physical location in the external transmission systems that are modeled in the Base Market Model, subject to the modeling of Transmission Losses in the portions of the FNM and exclusion of such Transmission Losses' effects on the LMPs that are external to the CAISO Balancing Authority Area described in this Section 27.5.1.1. The LMP price thus associated with a Dynamic System Resource or Pseudo-Tie Generating Unit will be used for Settlement of Energy and will include the Marginal Cost of Congestion and Marginal Cost of Losses components of the LMP to that Dynamic System Resource or Pseudo-Tie Generating Unit point, excluding losses and congestion external to the CAISO Balancing Authority Area, in accordance with this Section 27.5.1.1. Further, in formulating the market models for the CAISO Market processes, except for specific Intertie locations as specified in the BPM, power flow parameters developed from applicable data sources, including available outage information, system status data, and the State Estimator for the Real-Time Dispatch, are applied to the Base Market Model.

30.5.2 Supply Bids

30.5.2.1 Common Elements for Supply Bids

In addition to the resource-specific Bid requirements of this Section, all Supply Bids must contain the following components: Scheduling Coordinator ID Code; Resource Location or Resource ID, as appropriate; MSG Configuration ID, as applicable; PNode or Aggregated Pricing Node as applicable; Energy Bid Curve; Self-Schedule component; Ancillary Services Bid; RUC Availability Bid as applicable, the CAISO Market to which the Bid applies; Trading Day to which the Bid applies; Priority Type (if any), and a Transaction ID as created by the CAISO. Supply Bids offered in the CAISO Markets must be monotonically increasing. Energy Bids in the RTM must also contain a Bid for Ancillary Services to the extent the resource is certified and capable of providing Ancillary Service in the RTM up to the registered certified capacity for that Ancillary Service less any Day-Ahead Ancillary Services Awards.

Scheduling Coordinators must submit the applicable Supply Bid components, including Self-Schedules, for the submitted MSG Configuration.

Scheduling Coordinators submitting Bids for Scheduling Points must adhere to the e-Tagging requirements outlined in Section 30.6.2.

30.5.2.2 Supply Bids for Participating Generators

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Participating Generators shall contain the following components as applicable: Start-Up Bid, Minimum Load Bid, Ramp Rate, Minimum and Maximum Operating Limits; Energy Limit, Regulatory Must-Take/Must-Run Generation; Contingency Flag; and Contract Reference Number (if any). Scheduling Coordinators submitting these Bid components for a Multi-Stage Generating Resource must do so for the submitted MSG Configuration. Scheduling quantities that a Scheduling Coordinator schedules as Regulatory Must-Take Generation for a CHP Resource shall be limited to the quantity necessary in any hour to meet the reasonably anticipated industrial host's thermal requirements and shall not exceed any established RMTMax values. The CHP Resource owner or operator shall provide its Scheduling Coordinator with the Regulatory Must-Take Generation values and is solely responsible for the accuracy of the information. The

Scheduling Coordinator for the CHP Resource will schedule the quantities consistent with information provided subject to any contract rights between the CHP Resource Generating Unit owner or operator and its counter-party to any power purchase agreement regarding curtailment or dispatchability of the CHP Resource. If the CHP Resource Generating Unit has a power purchase agreement and its counter-party is not the Scheduling Coordinator for the resource, the parties to the agreement share the responsibility for ensuring that the Scheduling Coordinator schedules the resource consistent with contractual rights of the counter-parties. A Scheduling Coordinator for a Physical Scheduling Plant or a System Unit may include Generation Distribution Factors as part of its Supply Bid. If the Scheduling Coordinator has not submitted the Generation Distribution Factors applicable for the Bid, the CAISO will use default Generation Distribution Factors stored in the Master File. All Generation Distribution Factors used by the CAISO will be normalized based on Outage data that is available to the automated market systems. A Multi-Stage Generating Resource and its MSG Configurations are registered under a single Resource ID and Scheduling Coordinator for the Multi-Stage Generating Resource must submit all Bids for the resource's MSG Configurations under the same Resource ID. For a Multi-Stage Generating Resources Scheduling Coordinators may submit bid curves for up to ten individual MSG Configurations of their Multi-Stage Generating Resources into the Day-Ahead Market and up to three individual MSG Configurations into the Real-Time Market. Scheduling Coordinators for Multi-Stage Generating Resources must submit a single Operational Ramp Rate for each MSG Configuration for which it submits a supply Bid either in the Day-Ahead Market or Real-Time Market. For Multi-Stage Generating Resources the Scheduling Coordinator may submit the Transition Times, which cannot be greater than the maximum Transition Time registered in the Master File. To the extent the Scheduling Coordinator does not submit the Transition Time that is a registered feasible transition the CAISO will use the registered maximum Transition Time for that MSG Transition for the specific Multi-Stage Generating Resource.

30.5.2.3 Supply Bids for Participating Loads, Including Pumped-Storage Hydro Units and Aggregated Participating Loads

In addition to the common elements listed in Section 30.5.2.1, Scheduling Coordinators submitting Supply Bids for Participating Loads, which includes Pumping Load or Pumped-Storage

Hydro Units, may include the following components: Pumping Level (MW), Minimum Load Bid (Generation mode only of a Pumped-Storage Hydro Unit), Load Distribution Factor, Ramp Rate, Energy Limit, Pumping Cost, and Pump Shut-Down Costs. If no values for Pumping Cost or Pump Shut-Down Costs are submitted, the CAISO will generate these Bid components based on values in the Master File. Scheduling Coordinators may only submit Supply Bids for Aggregated Participating Loads by using a Generating Unit or Physical Scheduling Plant Resource ID for the Demand reduction capacity represented by the Aggregated Participating Load as set forth in a Business Practice Manual. The CAISO will use Generation Distribution Factors provided by the Scheduling Coordinator for the Aggregated Participating Load.

30.5.2.4 Supply Bids for System Resources

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for System Resources shall also contain: the relevant Ramp Rate; Start-Up Costs; and Minimum Load Costs. Resource-Specific System Resources may elect the Proxy Cost option or Registered Cost option for Start-Up Costs and Minimum Load Costs as provided in Section 30.4, and Transaction ID as created by the CAISO. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the HASP and RTM on an equivalent basis as Generating Units. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the HASP or RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted.

30.5.2.4.1 Intertie Block Bids

Intertie Block Bids must contain the same energy Bid price for all hours of the period for which the Intertie Block Bid is submitted. Intertie Block Bids may only be submitted in the DAM.

30.5.2.5 Supply Bids for Metered Subsystems

Consistent with the bidding rules specified in this Section 30.5, Scheduling Coordinators that represent MSS Operators may submit Bids for Energy and Ancillary Services, including Self-Schedules and Submissions to Self-Provide an Ancillary Service, to the DAM. All Bids to supply Energy by MSS Operators must identify each Generating Unit on an individual unit basis. The CAISO will not accept aggregated Generation Bids without complying with the requirements of Section 4.9.12 of the CAISO Tariff. All Scheduling Coordinators that represent MSS Operators must submit Demand Bids at the relevant MSS LAP. Scheduling Coordinators that represent MSS Operators must comply with Section 4.9 of the CAISO Tariff. Scheduling Coordinators that represent MSS Operators that have opted out of RUC participation pursuant to Section 31.5 must Self-Schedule one hundred percent (100%) of the Demand Forecast for the MSS. For an MSS that elects Load following, the MSS Operator shall also self-schedule or bid Supply to match the Demand Forecast. All Bids for MSSs must be identify each Generating Unit on an individual unit basis or a System Unit. For an MSS that elects Load following consistent with Section 4.9.13.2, the Scheduling Coordinator for the MSS Operator must include the following additional information with its Bids: the Generating Unit(s) that are Load following; the range of the Generating Unit(s) being reserved for Load following; whether the quantity of Load following capacity is either up or down; and, if there are multiple Generating Units in the MSS, the priority list or distribution factors among the Generating Units. The CAISO will not dispatch the resource within the range declared as Load following capacity, leaving that capacity entirely available for the MSS to dispatch. The CAISO uses this information in the IFM runs and the RUC to simulate MSS Load following. The Scheduling Coordinator for the MSS Operator may change these characteristics through the Bid submission process in the RTM.

If the Load following resource is also an RMR Unit, the MSS Operator must not specify the Maximum Net Dependable Capacity specified in the RMR Contract as Load following up or down capacity to allow the CAISO to access such capacity for RMR Dispatch.

30.5.2.6 Ancillary Services Bids

There are four distinct Ancillary Services: Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. A resource shall be eligible to provide Ancillary Service if it has complied with the CAISO's certification and testing requirements as contained in Appendix K and the CAISO's Operating Procedures. Scheduling Coordinators may use Dynamic System Resources to Self-Provide Ancillary Services as specified in Section 8. All System Resources, including Dynamic System Resources and Non-Dynamic System Resources, will be charged the Shadow Price as prescribed in Section 11.10, for any awarded Ancillary Services. A Scheduling Coordinator may submit Ancillary Services Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve for the same capacity by providing a separate price in $/MW per hour as desired for each Ancillary Service. The Bid for each Ancillary Services is a single Bid segment. Only resources certified by the CAISO as capable of providing Ancillary Services are eligible to provide Ancillary Services and submit Ancillary Services Bids. In addition to the common elements listed in Section 30.5.2.1, all Ancillary Services Bid components of a Supply Bid must contain the following: (1) the type of Ancillary Service for which a Bid is being submitted; (2) Ramp Rate (Operating Reserve Ramp Rate and Regulation Ramp Rate, if applicable); and (3) Distribution Curve for Physical Scheduling Plant or System Unit. A Scheduling Coordinator may only submit an Ancillary Services Bid or Submission to Self-Provide an Ancillary Service for Multi-Stage Generating Resources for the Ancillary Service for which the specific MSG Configurations are certified. For any such certified MSG Configurations the Scheduling Coordinator may submit only one Operating Reserve Ramp Rate and Regulation Ramp Rate. An Ancillary Services Bid submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but is not required to be, accompanied by an Energy Bid that covers the capacity offered for the Ancillary Service. Submissions to Self-Provide an Ancillary Services submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but are not required to be, accompanied by an Energy Bid that covers the capacity to be self-provided. If a Scheduling Coordinator's Submission to Self-Provide an Ancillary Service is qualified as specified in Section 8.6, the Scheduling Coordinator must submit an Energy Bid that covers the self-provided capacity prior to the close of the Real-Time Market for the day immediately following the Day-Ahead Market in which the Ancillary Service Bid was submitted. Except as provided below, the Self-Schedule for Energy need not include a Self-Schedule for Energy from the resource that will be self-providing the Ancillary Service. If a Scheduling Coordinator is self-providing an Ancillary Service from a Fast Start Unit, no Self-Schedule for Energy for that resource is required. If a Scheduling Coordinator proposes to self-provide Spinning Reserve, the Scheduling Coordinator is obligated to submit a Self-Schedule for Energy for that particular resource, unless as discussed above the particular resource is a Fast Start Unit. When submitting Ancillary Service Bids in the Real-Time Market, Scheduling Coordinators for resources that either have been awarded or self-provide Spinning Reserve or Non-Spinning Reserve capacity in the Day-Ahead Market must submit an Energy Bid for at least the awarded or self-provided Spinning Reserve or Non-Spinning Reserve capacity, otherwise the CAISO will apply the Bid validation rules described in Section 30.7.6.1. As provided in Section 30.5.2.6.4, a Submission to Self-Provide an Ancillary Service shall contain all of the requirements of a Bid for Ancillary Services with the exception of Ancillary Service Bid price information. In addition, Scheduling Coordinators must comply with the Ancillary Services requirements of Section 8. Scheduling Coordinators submitting Self-Schedule Hourly Blocks for Ancillary Services Bids for the Real-Time Market must also submit an Energy Bid for the associated Ancillary Services Bid under the same Resource ID, otherwise the bid validation rules in Section 30.7.6.1 will apply to cover any portion of the Ancillary Services Bid not accompanied by an Energy Bid. As described in Section 34.2.3, if the resource submits a Self-Scheduled Hourly Block, the CAISO will only use the Ancillary Services Bid in the RTM optimization and will not use the associated Energy Bid for the same Resource ID to schedule Energy from the Non-Dynamic System Resource in the RTM. Scheduling Coordinators must also comply with the bidding rules associated with the must offer requirements for Ancillary Services specified in Section 40.6.

30.5.2.6.1 Regulation Up or Regulation Down Bid Information

In the case of Regulation Up or Regulation Down, the Ancillary Services Bid or submission to self-provide must also contain: (a) the upward and downward range of generating capacity over which the resource is willing to provide Regulation in ten (10) minutes; (b) the Bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($/MW) and (c) the Bid price ($) of the Mileage stated separately for Regulation Up and Regulation Down. For submissions to self-provide Regulation Up or Regulation Down, the price for the capacity reservation shall be $0/MWh and the price for Mileage shall be $0. In the case of Regulation Up or Regulation Down from Dynamic System Resources, the Ancillary Services Bid must also contain the Contract Reference Number, if applicable. Scheduling Coordinators may include inter-temporal opportunity costs in their Regulation capacity bids, but these inter-temporal opportunity costs must be verifiable. Ancillary Services Bids submitted to the Day-Ahead or Real-Time Market for Regulation need not be accompanied by an Energy Supply Bid that covers the Ancillary Services capacity being offered. A Regulation Down Bid will be erased unless there is an Energy Supply Bid or Energy Self-Schedule at a level that would permit the resource to provide Regulation Down to its lower Regulation Limit. A submission to self-provide Regulation Down will be erased unless there is an Energy Self-Schedule at a level that would permit the resource to provide Regulation Down to its lower Regulation Limit. A Regulation Up Bid will be erased unless there is an Energy Supply Bid or Energy Self-Schedule at a level that would permit the resource to provide Regulation Up within its Regulation Limit. A submission to self-provide Regulation Up will be erased unless there is an Energy Self-Schedule at a level that would permit the resource to provide Regulation Up within its Regulation Limit.

30.5.2.6.2 Spinning Reserve Capacity Bid Information

In the case of Spinning Reserve capacity, the Ancillary Services Bid must also contain: (a) MW of additional capability synchronized to the system, immediately responsive to system frequency, and available within ten (10) minutes; (b) Bid price of capacity reservation, and (c) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency (Contingency Flag). In the case of Spinning Reserve capacity from System Resources, the Ancillary Services Bid must also contain: (a) Schedule ID (NERC ID number), and (b) a Contract Reference Number, if applicable. Ancillary Services Bids and Submissions to

Self-Provide an Ancillary Services submitted to the Real-Time Market for Spinning Reserves must also submit an Energy Bid that covers the Ancillary Services capacity being offered into the Real-Time Market.

30.5.2.6.3 Non-Spinning Reserve Capacity

In the case of Non-Spinning Reserve, the Ancillary Service Bid must also contain: (a) the MW capability available within ten (10) minutes; (b) the Bid price of the capacity reservation; (c) time of synchronization following notification (minutes); and (d) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency (Contingency Flag). In the case of Non-Spinning Reserve Capacity from System Resources, the Ancillary Services Bid must also contain: (a) Schedule ID (NERC ID number); and (b) a Contract Reference Number, if applicable. In the case of Non-Spinning Reserve Capacity from Participating Load within the CAISO Balancing Authority Area, the Ancillary Service Bid must also contain: (a) a Load identification name and Location Code, (b) Demand reduction available within ten (10) minutes, (c) time to interruption following notification (minutes), and (d) maximum allowable curtailment duration (hour). In the case of Aggregated Participating Load, and Proxy Demand Resources, Scheduling Coordinators must submit Bids using a Generating Unit, Physical Scheduling Plant Resource ID, or Resource ID for the Proxy Demand Resource for the Demand reduction capacity of the Aggregated Participating Load through a Bid to provide Non-Spinning Reserve or a Submission to Self-Provide an Ancillary Service for Non-Spinning Reserve. Ancillary Services Bids and Submissions to Self-Provide an Ancillary Services submitted to the Real-Time Market for Non-Spinning Reserves must also submit an Energy Bid that covers the Ancillary Services capacity being offered into the Real-Time Market.

30.5.2.6.4 Additional Rules For Self-Provided Ancillary Services

Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in this Section 30.5 in relation to each Ancillary Service to be self-provided, excluding the capacity price information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades. The portion of the Energy Bid that corresponds to the high end of the resource's operating range, shall be allocated to any awarded or Self-Provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; and (c) Non-Spinning Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Energy.

30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units capacity that is not Resource Adequacy Capacity or CPM Capacity in the DAM. Scheduling Coordinators for Resource Adequacy Capacity or CPM Capacity must participate in RUC to the extent that such capacity is not reflected in an IFM Schedule but need not submit RUC Availability Bids. Resource Adequacy Capacity participating in RUC will be optimized using a zero dollar ($0/MW-hour) RUC Availability Bid. For Multi-Stage Generating Resources, the RUC Availability Bids shall be submitted at the MSG Configuration. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour.

31.8 Constraints Enforced at Interties

31.8.1 Scheduling Constraint

Within the IFM and RTM optimizations, the CAISO enforces a constraint at each CAISO Intertie such that physical and virtual imports net of physical and virtual exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. The CAISO incorporates the Shadow Price of this IFM constraint into the CAISO Market runs used to establish LMPs for both physical and virtual awards. Within the RUC process, the CAISO enforces a constraint at each Intertie such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this RUC constraint the CAISO determines what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead. Day-Ahead Schedules precluded from submitting an E-Tag in the Day-Ahead on this basis are exempt from the charges described in Section 11.32.

31.8.2 Physical Flow Constraint

The CAISO may enforce a physical flow constraint limit at each internal and Intertie location in the IFM taking into account the total power flow contributions, which include internal schedules and import/export schedules, which can be physical or virtual, and the CAISO's estimates of unscheduled flow at the Interties. The physical flow constraint limit at each Intertie is less than or equal to the Transmission Constraints, including Nomograms and Contingencies, affecting the Intertie. At each Intertie the scheduling and physical flow constraint limits may differ. In the RUC and RTM processes, the same physical flow constraint limit is applied and internal schedules and import/export schedules, which can only be physical, are considered along with the CAISO's estimates of unscheduled flow at the Interties. The CAISO will not enforce physical flow constraints at Interties for which the CAISO (1) is subject to contractual arrangements that provide for the management of unscheduled flows using other procedures; (2) has determined it cannot enforce the power flow constraints due to modeling inaccuracies, including inaccuracies in available data; or (3) has otherwise determined that enforcing the power flow constraints could result in adverse reliability impacts.

36.4 FNM For CRR Allocation And CRR Auction

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) TTC adjusted for any long-term scheduled derates, (iii) a downward adjustment due to TOR or ETC as determined by the CAISO, and (iv) the impact on transmission elements used in the annual CRR Allocation and Auction of (a) transmission Outages or derates that are not scheduled at the time the CAISO conducts the Seasonal CRR Allocation or Auction determined through a methodology that calculates the breakeven point for revenue adequacy based on historical Outages and derates, and (b) known system topology changes, both as further defined in the Business Practice Manuals. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month as submitted for approval consistent with the criteria specified in Section 36.4.3, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages, (iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) TTC adjusted for any scheduled derates or Outages for that month, (vi) a downward adjustment due to TOR or ETC as determined by the CAISO; and (vii) adjustments for possible unscheduled flow at the Interties. For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits, based on statistical factors determined as provided in the Business Practice Manuals.

- Intertie

A transmission corridor that interconnects the CAISO Balancing Authority Area with another Balancing Authority Area.

- Scheduling Point

A location in the Base Market Model at which Scheduling Coordinators may submit Intertie Bids in the CAISO Markets.

- Transaction ID

Identification characters generated by the CAISO when Bids are submitted by Scheduling Coordinators at Interties for resources whose characteristics are not registered in the Master File such as Non-Dynamic System Resources. The Transaction IDs remain associated with specific transactions represented in the Bid from Bid validation through Settlement of the Bid if cleared through the CAISO Markets. Transaction IDs are not assigned to Bids associated with resources whose characteristics are registered in the Master File such as Resource Adequacy Capacity, Transmission Ownership Rights, Existing Transmission Contracts, resources certified for Ancillary Services or other contractual agreements that the CAISO is required to honor.

Attachment B – Marked Tariff Sheets

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

6.5.10 Protected Communications with Market Participants

6.5.10.1 Protected Data

The CAISO will provide to parties that have signed a Non-Disclosure Agreement in accordance with Section 6.5.10, the following Protected Data:

6.5.10.1.1 Transmission Constraints Enforcement List

After the results of the Day-Ahead Market are posted, the CAISO will provide the daily post-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the list of Transmission Constraints, including Contingencies and Nomograms that are enforced and not enforced in that day's Day-Ahead Market. Subsequently and prior to the next Day-Ahead Market, the CAISO will provide to parties the pre-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the daily list of information for the Transmission Constraints, including Contingencies and Nomograms, the CAISO plans to enforce or not enforce for the next day's Day-Ahead Market. To the extent that the CAISO does not make either of these two reports available on any given Operating Day, the CAISO will instead provide within the next thirty (30) days only the list of Transmission Constraints, including Contingencies and Nomograms, that were enforced or not enforced for the applicable Day-Ahead Market, after which the information will not be provided.

6.5.10.1.2 Load Distribution Factors

Three (3) days after the applicable Trading Day, the CAISO will provide the actual Load Distribution Factors used in the Integrated Forward Market for the applicable Trading Day. The CAISO will provide the Load Distribution Factors for each of the Default LAPs' underlying Pricing Nodes for all Pricing Nodes that are identified by the responsible Utility Distribution Company as Pricing Nodes at which there is more than just a single customer. For Pricing Nodes that the responsible Utility Distribution Company has not identified as Pricing Nodes at which there is more than just a single customer, the ISO will publish the respective Load Distribution Factors in a single aggregated location capturing all such nodes. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report within the next thirty (30) days for the applicable Integrated Forward Market, after which the information will not be provided.

6.5.10.1.3 Power Transfer Distribution Factors

Three (3) days after the applicable Trading Day, the CAISO will provide the Integrated Forward Market, HASP and Real-Time Dispatch Power Transfer Distribution Factors for each binding Transmission Constraint in the respective markets. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report for any given successful Integrated Forward Market, HASP and Real-Time Dispatch run within the next thirty (30) days, after which the information will not be provided.

6.5.10.1.4 Transmission Constraints Limits

6.5.10.1.4 Transmission Constraints Limits

Three (3) days after the applicable Trading Day, the CAISO will provide a report on the limits associated with all Transmission Constraints, including Nomograms, branch groups, and individual transmission facilities, under both base case and contingencies, that are enforced in the Integrated Forward Market, FMM~~, HASP~~ and Real-Time Dispatch, and that based on the flows in the respective market runs are approaching the limits. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report within the next thirty (30) days for any given successful Integrated Forward Market, FMM~~HASP~~ and Real-Time Dispatch run, after which the information will not be provided.

6.5.10.1.5 Unscheduled Flow Estimates

After the results of the Day-Ahead Market are posted, the CAISO will provide the hourly unscheduled flow at each Intertie considered in the Day-Ahead Market. After the results of the Real-Time Market are posted, the CAISO will provide the unscheduled flow at each Intertie considered in the Real-Time Market. To the extent that the CAISO fails to provide this report on any given Operating Day, the CAISO will endeavor to provide this report within the next thirty (30) days for the applicable Day-Ahead Market and Real-Time Market, after which the information will not be provided.

6.5.10.2 Requirements to Obtain the Protected Data

The CAISO shall provide the Protected Data only to those Market Participants and non-Market

Participants that satisfy the following requirements.

(a) To obtain access to the Protected Data, a Market Participant that is a member of the WECC that requests the Protected Data must: (i) execute and submit to the CAISO the Non-Disclosure Agreement for Protected Data that is posted on the CAISO Website; and (ii) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the Market Participant, executed by each employee and consultant of the Market Participant who will have access to the Protected Data.

(b) To obtain access to the Protected Data, a Market Participant that is not a member of the WECC that requests the Protected Data must: (i) execute and submit to the CAISO the Non-Disclosure Agreement for Protected Data that is posted on the CAISO Website, (ii) provide to the CAISO a fully executed WECC Non-Member Confidentiality Agreement for WECC Data, and (iii) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the non-WECC Market Participant, executed by each employee and consultant of the non-WECC Market Participant who will have access to the Protected Data.

(c) To obtain access to the Protected Data a non-Market Participant that is a member of the WECC that requests the Protected Data must: (i) reasonably demonstrate a legitimate business or governmental interest in the CAISO Markets, (ii) execute the Non-Disclosure Agreement for Protected Data posted on the CAISO Website, and (iii) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the non-Market Participant, executed by each employee and consultant of the non-Market Participant who will have access to the Protected Data.

(d) To obtain access to the Protected Data , a non-Market Participant that is not a member of the WECC that requests the Protected Data must: (i) reasonably demonstrate a legitimate business or governmental interest in the CAISO Markets, (ii) execute the Non-Disclosure Agreement for Protected Data that is posted on the CAISO Website, (iii) provide to the CAISO a fully executed WECC Non-Member Confidentiality Agreement for WECC Data, and (iv) provide to the CAISO a non-disclosure statement, the form of which is attached as an exhibit to the Non-Disclosure Agreement executed by the non-Market Participant, executed by each employee and consultant of the non-Market Participant who will have access to the Protected Data.

6.5.10.3 Obligation to Report Violations of Section 6.5.10

Each Market Participant, non-Market Participant, employee of a Market Participant, employee of a non-Market Participant, consultant, and employee of a consultant to whom the CAISO distributes the Protected Data shall be obligated to immediately report to the CAISO any violation of the requirements of Section 6.5.10.

11.2 Settlement Of Day-Ahead Market Transactions

All transactions in the IFM and RUC as specified in the Day-Ahead Schedule, AS Awards and RUC Awards, respectively, are financially binding and will be settled based on the Day-Ahead LMP, ASMP or RUC Price for the relevant Location for the specific resource or transaction identified ~~in~~ for the Bid. The CAISO will settle the costs of Demand, capacity, Energy and Ancillary Services as separate Settlement charges and payments for each Settlement Period of the Day-Ahead Schedule, Day-Ahead AS Award or RUC Award, as appropriate.

27.1.2 Ancillary Service Prices

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM and the FMM, and the CAISO also accepts and awards HASP Block Intertie Schedules for Ancillary Services in HASP. Ancillary Services awarded through HASP are made financially binding in the FMM. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO accepts and awards Ancillary Services from HASP Block Intertie Schedules for the next Trading Hour as described in Section 34.2. The CAISO calculates the price for the settlement of Ancillary Services accepted and awarded in HASP based on the FMM ASMP as described herein and further described in Section 34.4. The FMM process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

27.1.2.2 Opportunity Cost in ASMP

The Ancillary Services Shadow Price, which, as described above, is a result of the Energy and Ancillary Service co-optimization, includes the foregone opportunity cost of the marginal resource, if any, for not providing Energy or other types of Ancillary Services the marginal resource is capable of providing in the relevant market. The ASMPs determined by the IFM or FMM optimization process for each resource whose Ancillary Service Bid is accepted will be no lower than the sum of (i) the Ancillary Service capacity Bid price submitted for that resource, and (ii) the foregone opportunity cost of Energy in the IFM or FMM for that resource. The foregone opportunity cost of Energy for this purpose is measured as the positive difference between the IFM or FMM LMP at the resource's Pricing Node and the resource's Energy Bid price. If the resource's Energy Bid price is higher than the LMP, the opportunity cost measured for this calculation is $0. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is under an obligation to offer Energy in the Day-Ahead Market (e.g. a non-hydro Resource Adequacy Resource), its Default Energy Bid will be used, and its opportunity cost will be calculated accordingly. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is not under an obligation to offer Energy in the Day-Ahead Market, its Energy opportunity cost measured for this calculation is $0 since it cannot be dispatched for Energy. For Self-Scheduled Hourly Block Bids for Ancillary Services awarded in the Real-Time Market~~HASP~~, the opportunity cost measured for this purpose is $0 because, as provided in Section 34.2.3**,** the CAISO cannot Schedule Energy in the Real-Time Market~~HASP~~ from the Energy Bid under the same Resource ID as the submitted Ancillary Service Bid.

27.1.2.3 Ancillary Services Pricing – Insufficient Supply

The CAISO will develop Scarcity Reserve Demand Curves as further described in an applicable Business Practice Manual that will apply to both the Day-Ahead Market and the Real-Time Market during periods in which supply is insufficient to meet the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up as required by Section 8.3. During the first three (3) years in which the CAISO's Scarcity Reserve Demand Curves are effective, the CAISO shall conduct an annual review of the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary, with the exception that the ISO will not conduct this assessment in any year in which the Scarcity Reserve Demand Curves are not triggered. Thereafter, the CAISO shall review the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary every three (3) years or more frequently, if the CAISO determines more frequent reviews are appropriate. When supply is insufficient to meet any of the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up, the Scarcity Reserve Demand Curve Values for the affected Ancillary Services, as set forth in this Section 27.1.2.3 and as reflected in the in the Scarcity Demand Curve Value table below, shall apply to determine the Shadow Prices of the affected Ancillary Services. ASMPs for an Ancillary Service type will not sum these Shadow Prices across Ancillary Service Regions, if there is insufficient supply for the Ancillary Service type in both the Expanded System Region and an Ancillary Service Sub-Region.

Reserve	**Scarcity Demand Curve Value ($/MWh)**					
	Percent of Energy Max Bid Price		**Max Energy Bid Price = $750/MWh**		**Max Energy Bid Price = $1000/MWh**	
	Expanded System Region	**System Region and Sub-Region**	**Expanded System Region**	**System Region and Sub-Region**	**Expanded System Region**	**System Region and Sub-Region**

Regulation Up	20%	20%	$150	$150	$200	$200
Spinning	10%	10%	$75	$75	$100	$100
Non-Spinning						
Shortage > 210 MW	70%	70%	$525	$525	$700	$700
Shortage > 70 & ≤ 210 MW	60%	60%	$450	$450	$600	$600
Shortage ≤ 70 MW	50%	50%	$375	$375	$500	$500
Upward Sum	**100%**	**100%**	**$750**	**$750**	**$1000**	**$1000**
Regulation Down						
Shortage > 84 MW	70%	70%	$525	$525	$700	$700
Shortage > 32 & ≤ 84 MW	60%	60%	$450	$450	$600	$600
Shortage ≤ 32 MW	50%	50%	$375	$375	$500	$500

27.1.2.3.1 Regulation Down Pricing – Insufficient Supply

When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be fifty (50) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is less than or equal to eighty-four (84) MW but greater than thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be sixty (60) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is greater than eighty-four (84) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be seventy (70) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.2 Non-Spinning Reserve Pricing – Insufficient Supply

When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be fifty (50) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is less than or equal to two-hundred ten (210) MW but greater than seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be sixty (60) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is greater than two-hundred ten (210) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be seventy (70) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.3 Spinning Reserve Pricing – Insufficient Supply

The Scarcity Reserve Demand Curve Value for Spinning Reserve in the Expanded System Region or in an Ancillary Service Sub-Region shall be ten (10) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.4 Regulation Up Pricing – Insufficient Supply

The Scarcity Reserve Demand Curve Value for Regulation Up in the Expanded System Region or in an Ancillary Service Sub-Region shall be twenty (20) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.4 Opportunity Cost in LMPs for Energy

In the event that there is insufficient supply to meet an Ancillary Services procurement requirement in a particular Ancillary Service Region or Sub-Region, the Ancillary Services Shadow Prices will rise automatically to the Scarcity Reserve Demand Curve Values in that

Ancillary Service Region or Sub-Region. LMPs for Energy will reflect the forgone opportunity cost of the marginal resource, if any, for not providing the scarce Ancillary Services consistent with the CAISO's co-optimization design.

27.4 Optimization In The CAISO Markets Processes

The CAISO runs the Day-Ahead Market~~AM, HASP~~ and Real-Time Market~~TM~~ and their component CAISO Markets Processes utilizing a set of integrated optimization programs, including SCUC and SCED.

27.4.3 CAISO Markets Scheduling And Pricing Parameters

The SCUC and SCED optimization software for the CAISO Markets utilize a set of configurable scheduling and pricing parameters to enable the software to reach a feasible solution and set appropriate prices in instances where Effective Economic Bids are not sufficient to allow a feasible solution. The scheduling parameters specify the criteria for the software to adjust Non-priced Quantities when such adjustment is necessary to reach a feasible solution. The scheduling parameters are configured so that the SCUC and SCED software will utilize Effective Economic Bids as far as possible to reach a feasible solution, and will skip Ineffective Economic Bids and perform adjustments to Non-priced Quantities pursuant to the scheduling priorities for Self-Schedules specified in Sections 31.4 and 34.10. The scheduling parameters utilized for relaxation of enforced internal and Intertie Transmission Constraints are specified in Section 27.4.3.1. The pricing parameters specify the criteria for establishing market prices in instances where one or more Non-priced Quantities are adjusted by the Market Clearing software. The pricing parameters are specified in Sections 27.1.2.3, 27.4.3.2, 27.4.3.3 and 27.4.3.4. The complete set of scheduling and pricing parameters used in all CAISO Markets is maintained in the Business Practice Manuals.

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an enforced ~~internal~~ internal and Intertie Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5,000 per MWh or less for the IFM (or $1,500 per MWh or less for the RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5,000 per MWh in the IFM (or $1,500 per MWh for the RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1,250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

27.4.3.3 Insufficient Supply to Meet Self-Scheduled Demand in IFM

In the IFM, when available supply is insufficient to meet all self-scheduled Demand, self-scheduled Demand is reduced to the point where the available supply is sufficient to clear the market. For price-setting purposes in such cases, the cleared self-scheduled Demand is deemed to be willing to pay the maximum Energy Bid price specified in Section 39.6.1.1.

27.4.3.4 Insufficient Supply to Meet CAISO Forecast of CAISO Demand in the RTM

In the RTM, in the event that Energy offers are insufficient to meet the CAISO Forecast of CAISO Demand, the SCUC and SCED software will relax the system energy-balance constraint. In such cases the software utilizes a pricing parameter set to the maximum Energy Bid price specified in Section 39.6.1.1 for price-setting purposes.

27.4.3.5 Protection of TOR, ETC and Converted Rights Self-Schedules in the IFM

In accordance with the submitted and accepted TRTC Instructions, valid Day-Ahead TOR Self-Schedules, Day-Ahead ETC Self-Schedules and Day-Ahead Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. The scheduling parameters associated with the TOR, ETC, or Converted Rights Self-Schedules will be set to values higher than the scheduling parameter associated with relaxation of an enforced internal and Intertie Transmission Constraint as specified in Section 27.4.3.1, so that when there is a congested Transmission Constraint that would otherwise subject a Supply or Demand resource submitted in a valid and balanced ETC, TOR or Converted Rights Self-Schedule to adjustment in the IFM, the IFM software will relax the Transmission Constraint rather than curtail the TOR, ETC, or Converted Rights Self-Schedule. This priority will be adhered to by the operation of the IFM Market Clearing software, and if necessary, by adjustment of Schedules after the IFM has been executed and the results have been reviewed by the CAISO operators.

27.4.3.6 Effectiveness Threshold

The CAISO Markets software includes a lower effectiveness threshold setting which governs whether the software will consider a bid "effective" for managing congestion on a congested Transmission Constraint. The CAISO will set this threshold at two (2) percent.

27.5.1 Network Models used in CAISO Markets

The FNM is a representation of the WECC network model including the CAISO Balancing Authority Area that enables the CAISO to produce a Base Market Model that the CAISO then uses as the basis for formulating the individual market models used to conduct power flow analyses to manage Transmission Constraints for the optimization of each of the CAISO Markets.

27.5.1.1 Base Market Model used in the CAISO Markets

Based on the FNM the CAISO creates the Base Market Model, which is used as the basis for formulating, as described in section 27.5.6, the individual market models used in each of the CAISO Markets to establish, enforce, and manage the enforced internal and Intertie Transmission Constraints associated with network facilities. The Base Market Model is derived from the FNM by (1) introducing locations for modeling Intertie Schedules; and (2) introducing market resources that do not currently exist in the FNM due to their size and lack of visibility. In the Base Market Model, external Balancing Authority Areas and external transmission systems are modeled to the extent necessary to 1) improve the accuracy of the CAISO Market solutions for purposes of reliable operations, and 2) support the commercial requirements of the CAISO Markets. For those portions of the FNM that are external to the CAISO Balancing Authority Area, the Base Market Model may model the resistive component for accurate modeling of Transmission Losses, but accounts for losses in the external portions of the market model separately from Transmission Losses within the CAISO Balancing Authority Area. As a result, the Marginal Cost of Losses in the LMPs is not affected by external losses. For portions of the Base Market Model that are external to the CAISO Balancing Authority Area, the CAISO Markets only enforce Transmission Constraints that reflect limitations of the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating Transmission Owner, or that affect Congestion Management within the CAISO Balancing Authority Area or on Interties. External connections are retained between Intertie branches within Transmission Interfaces. Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. The CAISO Markets' optimizations also factor in forecasted unscheduled flow at the Interties consistent with the requirements specified in the Business Practice Manuals. Resources are modeled at the appropriate network Nodes. The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Unit is connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model~~-~~ for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid. Based on the Base Market Model, the market models used in each of the CAISO ~~markets~~ Markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, FMM Schedules, Dispatch Instructions, and LMPs resulting from each CAISO Markets Process. The Dispatch, Schedule, and LMP of a Dynamic System Resource or Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area refer to a PNode, or Aggregated Pricing Node, if applicable, of the resource at its physical location in the external transmission systems that are modeled in the Base Market Model, subject to the modeling of Transmission Losses in the portions of the FNM and exclusion of such Transmission Losses' effects on the LMPs that are external to the CAISO Balancing Authority Area described in this Section 27.5.1.1. The LMP price thus associated with a Dynamic System Resource or Pseudo-Tie Generating Unit will be used for Settlement of Energy and will include the Marginal Cost of Congestion and Marginal Cost of Losses components of the LMP to that Dynamic System Resource or Pseudo-Tie Generating Unit point, excluding losses and congestion external to the CAISO Balancing Authority Area, in accordance with this Section 27.5.1.1. Further, in formulating the market models for the ~~RTM~~ CAISO Market processes, except for specific Intertie locations as specified in the BPM,~~the Real-Time~~ power flow parameters developed from applicable data sources, including available outage information, system status data, and the State Estimator for the Real-Time Dispatch, are applied to the Base Market Model.

30.5.2 Supply Bids

30.5.2.1 Common Elements for Supply Bids

In addition to the resource-specific Bid requirements of this Section, all Supply Bids must contain the following components: Scheduling Coordinator ID Code; Resource Location or Resource ID, as appropriate; MSG Configuration ID, as applicable; PNode or Aggregated Pricing Node as applicable; Energy Bid Curve; Self-Schedule component; Ancillary Services Bid; RUC Availability Bid as applicable, the CAISO Market to which the Bid applies; Trading Day to which the Bid applies; Priority Type (if any), and a Transaction ID as created by the CAISO. Supply Bids offered in the CAISO Markets must be monotonically increasing. Energy Bids in the RTM must also contain a Bid for Ancillary Services to the extent the resource is certified and capable of providing Ancillary Service in the RTM up to the registered certified capacity for that Ancillary Service less any Day-Ahead Ancillary Services Awards.

Scheduling Coordinators must submit the applicable Supply Bid components, including Self-Schedules, for the submitted MSG Configuration.

Scheduling Coordinators submitting Bids for Scheduling Points must adhere to the e-Tagging requirements outlined in Section 30.6.2.

30.5.2.2 Supply Bids for Participating Generators

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Participating Generators shall contain the following components as applicable: Start-Up Bid, Minimum Load Bid, Ramp Rate, Minimum and Maximum Operating Limits; Energy Limit, Regulatory Must-Take/Must-Run Generation; Contingency Flag; and Contract Reference Number (if any). Scheduling Coordinators submitting these Bid components for a Multi-Stage Generating Resource must do so for the submitted MSG Configuration. Scheduling quantities that a Scheduling Coordinator schedules as Regulatory Must-Take Generation for a CHP Resource shall be limited to the quantity necessary in any hour to meet the reasonably anticipated industrial host’s thermal requirements and shall not exceed any established RMTMax values. The CHP Resource owner or operator shall provide its Scheduling Coordinator with the Regulatory Must-Take Generation values and is solely responsible for the accuracy of the information. The

Scheduling Coordinator for the CHP Resource will schedule the quantities consistent with information provided subject to any contract rights between the CHP Resource Generating Unit owner or operator and its counter-party to any power purchase agreement regarding curtailment or dispatchability of the CHP Resource. If the CHP Resource Generating Unit has a power purchase agreement and its counter-party is not the Scheduling Coordinator for the resource, the parties to the agreement share the responsibility for ensuring that the Scheduling Coordinator schedules the resource consistent with contractual rights of the counter-parties. A Scheduling Coordinator for a Physical Scheduling Plant or a System Unit may include Generation Distribution Factors as part of its Supply Bid. If the Scheduling Coordinator has not submitted the Generation Distribution Factors applicable for the Bid, the CAISO will use default Generation Distribution Factors stored in the Master File. All Generation Distribution Factors used by the CAISO will be normalized based on Outage data that is available to the automated market systems. A Multi-Stage Generating Resource and its MSG Configurations are registered under a single Resource ID and Scheduling Coordinator for the Multi-Stage Generating Resource must submit all Bids for the resource's MSG Configurations under the same Resource ID. For a Multi-Stage Generating Resources Scheduling Coordinators may submit bid curves for up to ten individual MSG Configurations of their Multi-Stage Generating Resources into the Day-Ahead Market and up to three individual MSG Configurations into the Real-Time Market. Scheduling Coordinators for Multi-Stage Generating Resources must submit a single Operational Ramp Rate for each MSG Configuration for which it submits a supply Bid either in the Day-Ahead Market or Real-Time Market. For Multi-Stage Generating Resources the Scheduling Coordinator may submit the Transition Times, which cannot be greater than the maximum Transition Time registered in the Master File. To the extent the Scheduling Coordinator does not submit the Transition Time that is a registered feasible transition the CAISO will use the registered maximum Transition Time for that MSG Transition for the specific Multi-Stage Generating Resource.

30.5.2.3 Supply Bids for Participating Loads, Including Pumped-Storage Hydro Units and Aggregated Participating Loads

In addition to the common elements listed in Section 30.5.2.1, Scheduling Coordinators submitting Supply Bids for Participating Loads, which includes Pumping Load or Pumped-Storage

Hydro Units, may include the following components: Pumping Level (MW), Minimum Load Bid (Generation mode only of a Pumped-Storage Hydro Unit), Load Distribution Factor, Ramp Rate, Energy Limit, Pumping Cost, and Pump Shut-Down Costs. If no values for Pumping Cost or Pump Shut-Down Costs are submitted, the CAISO will generate these Bid components based on values in the Master File. Scheduling Coordinators may only submit Supply Bids for Aggregated Participating Loads by using a Generating Unit or Physical Scheduling Plant Resource ID for the Demand reduction capacity represented by the Aggregated Participating Load as set forth in a Business Practice Manual. The CAISO will use Generation Distribution Factors provided by the Scheduling Coordinator for the Aggregated Participating Load.

30.5.2.4 Supply Bids for System Resources

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for System Resources shall also contain: the relevant Ramp Rate; Start-Up Costs; and Minimum Load Costs. Resource-Specific System Resources may elect the Proxy Cost option or Registered Cost option for Start-Up Costs and Minimum Load Costs as provided in Section 30.4, and Transaction ID as created by the CAISO. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the HASP and RTM on an equivalent basis as Generating Units. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the HASP or RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted.

30.5.2.4.1 Intertie Block Bids

Intertie Block Bids must contain the same energy Bid price for all hours of the period for which the Intertie Block Bid is submitted. Intertie Block Bids may only be submitted in the DAM.

30.5.2.5 Supply Bids for Metered Subsystems

Consistent with the bidding rules specified in this Section 30.5, Scheduling Coordinators that represent MSS Operators may submit Bids for Energy and Ancillary Services, including Self-Schedules and Submissions to Self-Provide an Ancillary Service, to the DAM. All Bids to supply Energy by MSS Operators must identify each Generating Unit on an individual unit basis. The CAISO will not accept aggregated Generation Bids without complying with the requirements of Section 4.9.12 of the CAISO Tariff. All Scheduling Coordinators that represent MSS Operators must submit Demand Bids at the relevant MSS LAP. Scheduling Coordinators that represent MSS Operators must comply with Section 4.9 of the CAISO Tariff. Scheduling Coordinators that represent MSS Operators that have opted out of RUC participation pursuant to Section 31.5 must Self-Schedule one hundred percent (100%) of the Demand Forecast for the MSS. For an MSS that elects Load following, the MSS Operator shall also self-schedule or bid Supply to match the Demand Forecast. All Bids for MSSs must be identify each Generating Unit on an individual unit basis or a System Unit. For an MSS that elects Load following consistent with Section 4.9.13.2, the Scheduling Coordinator for the MSS Operator must include the following additional information with its Bids: the Generating Unit(s) that are Load following; the range of the Generating Unit(s) being reserved for Load following; whether the quantity of Load following capacity is either up or down; and, if there are multiple Generating Units in the MSS, the priority list or distribution factors among the Generating Units. The CAISO will not dispatch the resource within the range declared as Load following capacity, leaving that capacity entirely available for the MSS to dispatch. The CAISO uses this information in the IFM runs and the RUC to simulate MSS Load following. The Scheduling Coordinator for the MSS Operator may change these characteristics through the Bid submission process in the RTM.

If the Load following resource is also an RMR Unit, the MSS Operator must not specify the Maximum Net Dependable Capacity specified in the RMR Contract as Load following up or down capacity to allow the CAISO to access such capacity for RMR Dispatch.

30.5.2.6 Ancillary Services Bids

There are four distinct Ancillary Services: Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. A resource shall be eligible to provide Ancillary Service if it has complied with the CAISO's certification and testing requirements as contained in Appendix K and the CAISO's Operating Procedures. Scheduling Coordinators may use Dynamic System Resources to Self-Provide Ancillary Services as specified in Section 8. All System Resources, including Dynamic System Resources and Non-Dynamic System Resources, will be charged the Shadow Price as prescribed in Section 11.10, for any awarded Ancillary Services. A Scheduling Coordinator may submit Ancillary Services Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve for the same capacity by providing a separate price in $/MW per hour as desired for each Ancillary Service. The Bid for each Ancillary Services is a single Bid segment. Only resources certified by the CAISO as capable of providing Ancillary Services are eligible to provide Ancillary Services and submit Ancillary Services Bids. In addition to the common elements listed in Section 30.5.2.1, all Ancillary Services Bid components of a Supply Bid must contain the following: (1) the type of Ancillary Service for which a Bid is being submitted; (2) Ramp Rate (Operating Reserve Ramp Rate and Regulation Ramp Rate, if applicable); and (3) Distribution Curve for Physical Scheduling Plant or System Unit. A Scheduling Coordinator may only submit an Ancillary Services Bid or Submission to Self-Provide an Ancillary Service for Multi-Stage Generating Resources for the Ancillary Service for which the specific MSG Configurations are certified. For any such certified MSG Configurations the Scheduling Coordinator may submit only one Operating Reserve Ramp Rate and Regulation Ramp Rate. An Ancillary Services Bid submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but is not required to be, accompanied by an Energy Bid that covers the capacity offered for the Ancillary Service. Submissions to Self-Provide an Ancillary Services submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but are not required to be, accompanied by an Energy Bid that covers the capacity to be self-provided. If a Scheduling Coordinator's Submission to Self-Provide an Ancillary Service is qualified as specified in Section 8.6, the Scheduling Coordinator must submit an Energy Bid that covers the self-provided capacity prior to the close of the Real-Time Market for the day immediately following the Day-Ahead Market in which the Ancillary Service Bid was submitted. Except as provided below, the Self-Schedule for Energy need not include a Self-Schedule for Energy from the resource that will be self-providing the Ancillary Service. If a Scheduling Coordinator is self-providing an Ancillary Service from a Fast Start Unit, no Self-Schedule for Energy for that resource is required. If a Scheduling Coordinator proposes to self-provide Spinning Reserve, the Scheduling Coordinator is obligated to submit a Self-Schedule for Energy for that particular resource, unless as discussed above the particular resource is a Fast Start Unit. When submitting Ancillary Service Bids in the Real-Time Market, Scheduling Coordinators for resources that either have been awarded or self-provide Spinning Reserve or Non-Spinning Reserve capacity in the Day-Ahead Market must submit an Energy Bid for at least the awarded or self-provided Spinning Reserve or Non-Spinning Reserve capacity, otherwise the CAISO will apply the Bid validation rules described in Section 30.7.6.1. As provided in Section 30.5.2.6.4, a Submission to Self-Provide an Ancillary Service shall contain all of the requirements of a Bid for Ancillary Services with the exception of Ancillary Service Bid price information. In addition, Scheduling Coordinators must comply with the Ancillary Services requirements of Section 8. Scheduling Coordinators submitting Self-Schedule Hourly Blocks for Ancillary Services Bids for the Real-Time Market must also submit an Energy Bid for the associated Ancillary Services Bid under the same Resource ID, otherwise the bid validation rules in Section 30.7.6.1 will apply to cover any portion of the Ancillary Services Bid not accompanied by an Energy Bid. As described in Section 34.2.3, if the resource submits a Self-Scheduled Hourly Block, the CAISO will only use the Ancillary Services Bid in the RTM optimization and will not use the associated Energy Bid for the same Resource ID to schedule Energy from the Non-Dynamic System Resource in the RTM. Scheduling Coordinators must also comply with the bidding rules associated with the must offer requirements for Ancillary Services specified in Section 40.6.

30.5.2.6.1 Regulation Up or Regulation Down Bid Information

In the case of Regulation Up or Regulation Down, the Ancillary Services Bid or submission to self-provide must also contain: (a) the upward and downward range of generating capacity over which the resource is willing to provide Regulation in ten (10) minutes; (b) the Bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($/MW) and (c) the Bid price ($) of the Mileage stated separately for Regulation Up and Regulation Down. For submissions to self-provide Regulation Up or Regulation Down, the price for the capacity reservation shall be $0/MWh and the price for Mileage shall be $0. In the case of Regulation Up or Regulation Down from Dynamic System Resources, the Ancillary Services Bid must also contain the Contract Reference Number, if applicable. Scheduling Coordinators may include inter-temporal opportunity costs in their Regulation capacity bids, but these inter-temporal opportunity costs must be verifiable. Ancillary Services Bids submitted to the Day-Ahead or Real-Time Market for Regulation need not be accompanied by an Energy Supply Bid that covers the Ancillary Services capacity being offered. A Regulation Down Bid will be erased unless there is an Energy Supply Bid or Energy Self-Schedule at a level that would permit the resource to provide Regulation Down to its lower Regulation Limit. A submission to self-provide Regulation Down will be erased unless there is an Energy Self-Schedule at a level that would permit the resource to provide Regulation Down to its lower Regulation Limit. A Regulation Up Bid will be erased unless there is an Energy Supply Bid or Energy Self-Schedule at a level that would permit the resource to provide Regulation Up within its Regulation Limit. A submission to self-provide Regulation Up will be erased unless there is an Energy Self-Schedule at a level that would permit the resource to provide Regulation Up within its Regulation Limit.

30.5.2.6.2 Spinning Reserve Capacity Bid Information

In the case of Spinning Reserve capacity, the Ancillary Services Bid must also contain: (a) MW of additional capability synchronized to the system, immediately responsive to system frequency, and available within ten (10) minutes; (b) Bid price of capacity reservation, and (c) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency (Contingency Flag). In the case of Spinning Reserve capacity from System Resources, the Ancillary Services Bid must also contain: (a) ~~Interchange ID code of the selling entity, (b)~~ Schedule ID (NERC ID number), and (~~c~~b) a Contract Reference Number, if applicable.

Ancillary Services Bids and Submissions to Self-Provide an Ancillary Services submitted to the Real-Time Market for Spinning Reserves must also submit an Energy Bid that covers the Ancillary Services capacity being offered into the Real-Time Market.

30.5.2.6.3 Non-Spinning Reserve Capacity

In the case of Non-Spinning Reserve, the Ancillary Service Bid must also contain: (a) the MW capability available within ten (10) minutes; (b) the Bid price of the capacity reservation; (c) time of synchronization following notification (minutes); and (d) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency (Contingency Flag). In the case of Non-Spinning Reserve Capacity from System Resources, the Ancillary Services Bid must also contain: (a) ~~Interchange ID code of the selling entity, (b)~~ Schedule ID (NERC ID number); and (~~c~~b) a Contract Reference Number, if applicable. In the case of Non-Spinning Reserve Capacity from Participating Load within the CAISO Balancing Authority Area, the Ancillary Service Bid must also contain: (a) a Load identification name and Location Code, (b) Demand reduction available within ten (10) minutes, (c) time to interruption following notification (minutes), and (d) maximum allowable curtailment duration (hour). In the case of Aggregated Participating Load, and Proxy Demand Resources, Scheduling Coordinators must submit Bids using a Generating Unit, Physical Scheduling Plant Resource ID, or Resource ID for the Proxy Demand Resource for the Demand reduction capacity of the Aggregated Participating Load through a Bid to provide Non-Spinning Reserve or a Submission to Self-Provide an Ancillary Service for Non-Spinning Reserve. Ancillary Services Bids and Submissions to Self-Provide an Ancillary Services submitted to the Real-Time Market for Non-Spinning Reserves must also submit an Energy Bid that covers the Ancillary Services capacity being offered into the Real-Time Market.

30.5.2.6.4 Additional Rules For Self-Provided Ancillary Services

Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in this Section 30.5 in relation to each Ancillary Service to be self-provided, excluding the capacity price information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades. The portion of the Energy Bid that corresponds to the high end of the resource's operating range, shall be allocated to any awarded or Self-Provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; and (c) Non-Spinning Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Energy.

30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units capacity that is not Resource Adequacy Capacity or CPM Capacity in the DAM. Scheduling Coordinators for Resource Adequacy Capacity or CPM Capacity must participate in RUC to the extent that such capacity is not reflected in an IFM Schedule but need not submit RUC Availability Bids. Resource Adequacy Capacity participating in RUC will be optimized using a zero dollar ($0/MW-hour) RUC Availability Bid. For Multi-Stage Generating Resources, the RUC Availability Bids shall be submitted at the MSG Configuration. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour.

31.8 Constraints Enforced at Intertie<u>s</u> ~~Scheduling Points~~

~~Within the IFM optimization, the CAISO enforces a constraint at each Intertie Scheduling Point such that Physical and virtual imports net of physical and virtual exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. The CAISO incorporates the Shadow Price of this IFM constraint into the CAISO Market runs used to establish LMPs for both physical and virtual awards. Within the RUC process, the CAISO enforces a constraint at each Intertie Scheduling Point such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this RUC constraint the CAISO determines what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead. Day-Ahead Schedules precluded from submitting an E-Tag in the Day-Ahead on this basis are exempt from the charges described in Section 11.32.~~

31.8.1 Scheduling Constraint

Within the IFM and RTM optimizations, the CAISO enforces a constraint at each CAISO Intertie ~~Scheduling Point~~ such that p~~P~~hysical and virtual imports net of physical and virtual exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. The CAISO incorporates the Shadow Price of this IFM constraint into the CAISO Market runs used to establish LMPs for both physical and virtual awards. Within the RUC process, the CAISO enforces a constraint at each Intertie ~~Scheduling Point~~ such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this RUC constraint the CAISO determines what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead. Day-Ahead Schedules precluded from submitting an E-Tag in the Day-Ahead on this basis are exempt from the charges described in Section 11.32.

31.8.2 Physical Flow Constraint

The CAISO may enforce a physical flow constraint limit at each internal and Intertie location in the IFM taking into account the total power flow contributions, which include internal schedules and import/export schedules, which can be physical or virtual, and the CAISO's estimates of unscheduled flow at the Interties. The physical flow constraint limit at each Intertie is less than or equal to the Transmission Constraints, including Nomograms and Contingencies, affecting the Intertie. At each Intertie the scheduling and physical flow constraint limits may differ. In the RUC and RTM processes, the same physical flow constraint limit is applied and internal schedules and import/export schedules, which can only be physical, are considered along with the CAISO's estimates of unscheduled flow at the Interties. The CAISO will not enforce physical flow constraints at Interties for which the CAISO (1) is subject to contractual arrangements that provide for the management of unscheduled flows using other procedures; (2) has determined it cannot enforce the power flow constraints due to modeling inaccuracies, including inaccuracies in available data; or (3) has otherwise determined that enforcing the power flow constraints could result in adverse reliability impacts.

36.4 FNM For CRR Allocation And CRR Auction

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) TTC adjusted for any long-term scheduled derates, (iii) a downward adjustment due to TOR or ETC as determined by the CAISO, and (iv) the impact on transmission elements used in the annual CRR Allocation and Auction of (a) transmission Outages or derates that are not scheduled at the time the CAISO conducts the Seasonal CRR Allocation or Auction determined through a methodology that calculates the breakeven point for revenue adequacy based on historical Outages and derates, and (b) known system topology changes, both as further defined in the Business Practice Manuals. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month as submitted for approval consistent with the criteria specified in Section 36.4.3, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages, (iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) TTC adjusted for any scheduled derates or Outages for that month, ~~and~~ (vi) a downward adjustment due to TOR or ETC as determined by the CAISO; and (vii) adjustments for possible unscheduled flow at the Interties. For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits, based on statistical factors determined as provided in the Business Practice Manuals.

- Intertie

A transmission corridor that ~~Scheduling Point at a point of~~ interconnects~~ion between~~ the CAISO Balancing Authority Area with another ~~and an interconnected~~ Balancing Authority Area.

- Scheduling Point

A location in the Base Market Model at which Scheduling Coordinators may submit Intertie Bids in the CAISO Markets. ~~the CAISO Controlled Grid or a transmission facility owned by a Transmission Ownership Right holder is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the CAISO's Operational Control.~~

- Transaction ID

Identification characters generated by the CAISO when Bids are submitted by Scheduling Coordinators at Interties for resources whose characteristics are not registered in the Master File such as Non-Dynamic System Resources. The Transaction IDs remain associated with specific transactions represented in the Bid from Bid validation through Settlement of the Bid if cleared through the CAISO Markets. Transaction IDs are not assigned to Bids associated with resources whose characteristics are registered in the Master File such as Resource Adequacy Capacity, Transmission Ownership Rights, Existing Transmission Contracts, resources certified for Ancillary Services or other contractual agreements that the CAISO is required to honor.

Attachment C – Draft Final Proposal

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

Full Network Model Expansion

Draft Final Proposal

December 30, 2013

Table of Contents

1 Changes from 10/30/2013 second revised straw proposal

This is the draft final proposal in this initiative.[1] Significant changes were made in the third revised straw proposal and are summarized here. Based on stakeholder feedback, the full proposal will be addressed and implemented in phases. This will allow the ISO to gain experience with the proposed improvements incrementally, analyze and learn from data collected, and propose refinements when appropriate. The ISO envisions two major phases with elements of the full proposal included in Phase 1 to be presented to the ISO Board of Governors at the February 2014 meeting with the intent of filing with the Federal Energy Regulatory Commission (FERC) for implementation in Fall 2014. The remaining elements will be included in Phase 2 which will continue in the stakeholder process and presented to the Board at a later time. There may be additional phases as not yet identified at this time. The table below summarizes the elements envisioned for each phase and the approximate timing for major milestones.

Phase	Elements of proposal	Timing for milestones
Phase 1	1. Expansion of the full network model topology 2. Modeling of base schedules - fully modeling September 8th entities and BAAs such as BPA to support modeling of the EIM entities 3. Introduction of Transaction IDs 4. Enforce constraints for both scheduled and physical flow 5. Incorporating base schedules into CRR model for consistency 6. Import and export bids will continue to be submitted, modeled, and priced at the current scheduling points at the interties (except for EIM entities) 7. Improvements to the HVDC modeling	Elements will be presented to Board of Governors in February 2014 and submitted to FERC as tariff amendment for Fall 2014 implementation.
Phase 2	1. Allow for the modeling of physical sources and sinks in the WECC for ISO market transactions through the creation of scheduling hubs 2. Consideration of additional tagging or settlement rules associated with scheduling at hubs 3. Remapping CRRs to scheduling hubs for consistency 4. Modeling of additional BAAs	Stakeholder process will restart after experience under Phase 1 implementation.
Future phases (TBD)	1. Modeling of additional BAAs	TBD

[1] The revised straw and straw proposals can be accessed at: http://www.caiso.com/Documents/StrawProposal-FullNetworkModelExpansion.pdf and the issue paper was provided as a presentation at the April 10, 2013 Market Performance and Planning Forum (starting page 40) and can be accessed at: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForumApr10_2013.pdf.

Overall, stakeholders are supportive of the objectives of this initiative which is to increase reliability and market efficiency by expanding the full network model. In order to achieve these objectives in the necessary timeframe, the most critical elements of the proposal were selected for inclusion in Phase 1. In order to address stakeholder comments, the remaining elements were moved to Phase 2 for further discussion. The elements in Phase 2 would further improve the ISO's modeling and market efficiency.

First, phasing the proposal addresses numerous stakeholder concerns that the original proposal was too expansive and that there was insufficient time to review and vet all the details. While the ISO has kept critical elements in Phase 1, Phase 2 elements will be addressed in a subsequent stakeholder process so that there is additional time for discussion. Moreover, Phase 1 performance can be reported back to stakeholders to inform the Phase 2 discussion.

Second, stakeholders voiced concern over implementing scheduling hubs for intertie transactions because this would be a major modeling change and affect congestion revenue rights (CRRs). The ISO now proposes to address this in Phase 2 so that the ISO can collect data from the Phase 1 implementation and create an analysis to compare the difference between the current use of scheduling points at the interties and the proposed scheduling hubs. Currently, there are also three major scheduling hubs proposed and this may also be refined based on observations or analysis from Phase 1. Importantly, the Phase 1 elements need to be implemented in order to create many of the analyses that stakeholders have requested.

Third, stakeholders objected to the proposed tagging rule that would accompany the implementation of scheduling hubs. Since the scheduling hub approach has moved to Phase 2, the ISO can work with stakeholders to develop an appropriate tagging or settlement rule. Stakeholders have suggested various alternatives and these can now be discussed in the continuing stakeholder process and perhaps be informed by data collected from Phase 1.

Fourth, stakeholders have asked that the implementation for the full proposal be delayed. The ISO believes that with the phased approach, Phase 1 can move towards Fall 2014 implementation while Phase 2's timing can be decided later. There has been, even before the September 8th, 2011 event, a desire to expand the ISO's full network model. The September 8th event provided both the urgency to accomplish this as well as an opportunity as this engendered greater cooperation from various parties throughout the WECC. However, the importance of the Fall 2014 implementation date is related to the Energy Imbalance Market (EIM) implementation. Though the impetus to expand the full network model did not come from EIM implementation, it has become clear to the ISO over the last several months that accurate modeling of the EIM Entities will also depend on modeling systems in which they are embedded, for which they are transmission-dependent, or with which they are highly interconnected. In addition, it will be important to include base flows in the ISO day-ahead market so the market can incorporate flows resulting from EIM Entity base schedules submitted in the day-ahead timeframe. Delaying Phase 1 elements may also delay EIM implementation. We discuss this in Section 5.

Lastly, stakeholders have requested an analysis showing that the Phase 1 elements would be an improvement over today's modeling. The ISO commits to conduct such an analysis before implementation but would not be able to do so until we receive the software code around the market simulation timeframe. We discuss this in Section 11.

All Phase 1 elements are in the body of this proposal whereas Phase 2 elements have been moved to the appendix. The summaries below highlight the major changes or clarifications between this and the third revised straw proposal.

Section 6.1 – The ISO provides additional clarification on the treatment of demand forecasts and the net scheduled interchange data. The ISO also provides a link to the WECC Reliability Coordinator's data request for hourly demand forecasts.

Section 6.3 – The ISO corrected a link to the WECC Unscheduled Flow Mitigation Procedure.

Section 11 – The ISO provides details on a pre-implementation analysis with a potential for a more robust analysis.

2 Executive summary

On September 8, 2011, a system disturbance in Arizona caused cascading outages and blackouts through Arizona, Southern California, and the Baja peninsula portion of Mexico. Given the severity and rapid propagation of the outages, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation conducted an inquiry to determine the causes of the outages and develop recommendations to prevent such events in the future. Two of the major recommendations from this inquiry included the need for greater visibility and modeling of external networks in the day-ahead timeframe leading to reliable real-time operation. Pursuant to these recommendations, this stakeholder process seeks to enhance the ISO's modeling of electrical flows throughout the Western Interconnection by expanding the Full Network Model to reflect both the ISO and its neighboring balancing authority areas. The external visibility provided by the expansion will improve market efficiency and reliability when the ISO uses its market processes to dispatch and schedule resources on the ISO-controlled grid.

These improvements include a reduction in unscheduled loop flow on the ISO system. Unscheduled loop flows occur because the rest of the Western Electricity Coordinating Council relies on contract path scheduling, which assumes that electricity flows along a designated point-to-point path, when in fact electricity flows over the path of least resistance. These flows are currently not captured in the ISO's Full Network Model, resulting in day-ahead modeled flows that do not match real-time conditions and can lead to infeasible schedules that need to be managed in the real-time. In addition, the current market model does not take into account the actual flow resulting from intertie dispatches in the real-time market – leading to inefficient pricing. Therefore, this stakeholder process seeks to better align modeled and actual flows by accounting for loop flows in the day-ahead timeframe and by more accurately modeling the flows resulting from intertie dispatches in the real-time market. Improved day-ahead modeling should decrease real-time congestion imbalance offset costs and exceptional dispatches.

Pursuant to federal recommendations after the September 8th, 2011 southwest outage, the ISO proposes to model external balancing authority areas in the WECC in phases. This first phase, targeted for an implementation date of Fall 2014, largely consists of entities involved in the September 8th event and entities that are highly integrated with the Energy Imbalance Market entity. Additional balancing authorities to model can be identified in later phases. Both the day-ahead and real-time modeling will be reflected at the balancing authority area level and include the native demand and generation to both serve native demand and support any net scheduled interchange. Exchanges between balancing authority areas will also be modeled. The collective modeling of these external balancing authority areas is to calculate a “base schedule” that will provide to the ISO an indication of the loop flow we can expect from all external transactions (*i.e.,* transactions that do not involve the ISO). Incorporating base schedules will result in feasible schedules for the real-time because the modeling will incorporate loop flows. Moreover, calculating the loop flows in the day-ahead timeframe will provide the ISO with more time to position the necessary resources to address expected real-time conditions. The modeling framework will also be able to reflect the most recent information on outages, derates, and contingencies.

Once we have the base schedules, we can then model cleared import and export bids with the ISO. The current model uses the simplifying assumption that some of the interties have a radial connection with the ISO and all of the sources and sinks of these imports and exports are assumed to be located at the interties, even when there is no generation or load located there. With full network model expansion, we can eliminate both of these simplifying assumptions by expanding the network topology and mapping the import and export bids to sources or sinks throughout the Western Electricity Coordinating Council. In previous papers, the ISO proposed to address both assumptions simultaneously. Based on stakeholder feedback, we will phase these two changes by incorporating the network topology expansion and base flow functionality first and addressing modeling ISO market imports and exports back to physical sources and sinks in a separate stakeholder process. For now, the ISO will continue to model imports and exports and market participants will continue to bid at the current scheduling points at the interties.

In Phase 2, the ISO the ISO will propose to schedule and price imports and exports at physical points external to the ISO. In pricing import and export bids, the external WECC system will be reflected via two major hubs, with some exceptions such as the Energy Imbalance Market entities and the integrated balancing authority areas. These North and South hubs were created to reflect the different flow impacts on Path 66 (or COI), a major WECC path under the ISO’s control. While modeling is at the balancing authority area level, the hubs are aggregations of the underlying balancing authority areas. Scheduling coordinators will be allowed to schedule from either hub to any intertie, pursuant to obtaining the necessary transmission to support the schedule and adhering to settlement or tagging rules to be developed.

The ISO will model the flow resulting from the base schedules and import and export bids cleared in the ISO market to generate a congestion component of the locational marginal price due to physical flow for each scheduling point under Phase 1. Under Phase 2, this will be modeled to reflect each scheduling hub. This additional congestion component will be incorporated into the locational marginal price for imports/exports in addition to the existing congestion component that reflects congestion relative to an intertie's contract path scheduling limit. Thus, the price at an intertie will include two congestion components: (1) a new congestion component that reflects congestion due to modeled physical flow, and (2) the existing congestion component based on each intertie's scheduling limit.

Lastly, this initiative proposes improvements to the ISO's current modeling of high voltage direct current transmission lines, which can be implemented in Phase 1.

3 Introduction and purpose

This stakeholder process is to enhance the ISO's modeling of the electrical system (*i.e.*, network model) for operating the ISO controlled grid through its market process used for dispatching and scheduling resources on the grid. These changes will improve the ISO's modeling of electrical flows throughout the Western Interconnection, which will result in improved reliability and market solutions. More accurate modeling will allow the ISO to better reflect and more consistently enforce constraints between the day-ahead and real-time markets. This should reduce the incidences of infeasible schedules, including physical and virtual schedules, which result in real-time congestion offset charges. Finally, more accurate modeling is a necessary compliment to the EIM market design.

On September 8, 2011, a system disturbance in Arizona caused cascading outages and blackouts through Arizona, Southern California, and the Baja peninsula portion of Mexico, which affected the following five balancing authorities: ISO, Arizona Public Service Company (APS), Imperial Irrigation District (IID), Western Area Power Administration-Lower Colorado (WALC), and Comision Federal de Electricidad (CFE).[2] The outages resulted in the loss of more than 7,000 MW of firm load.[3] In the ISO, all of the San Diego area lost power. ISO markets were temporarily suspended and prices were set administratively. Markets were not fully restored to normal operations until about 12 hours later.[4]

[2] Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations*, April 2012. Available at: http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf
[3] Department of Market Monitoring, *California ISO: Q3 Report on Market Issues and Performance*, November 8, 2011, page 4.
[4] The disturbance occurred at about 3:27 p.m., leading to power outages at 3:38 p.m., and the ISO market was fully restored at 4:00 a.m.

Given the severity and rapid propagation of the outages, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) conducted an inquiry to determine the causes of the outages and develop recommendations to prevent such events in the future. Following review of data, on-site visits at entities involved in the outages, and interviews and depositions, FERC and NERC issued a joint staff report in April 2012 that found that certain aspects of systems within the Western Interconnection were not operated in a secure state. The joint report offered 27 findings and recommendations for improvement. The findings and recommendations apply to various aspects of the operation of the Western Interconnection.

Two of these findings and recommendations in the joint report are the subject of this stakeholder process. The ISO is considering them together because both address the need for greater visibility and modeling of external networks leading to reliable real-time operation. The findings are: Finding 2 – Lack of Updated External Networks in Next-Day Study Models and Finding 11 – Lack of Real-Time External Visibility: Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. The two findings and recommendations are set forth in their entirety in Table 1.

Table 1
FERC/NERC Joint Staff Report Findings and Recommendations
September 8th Event

Finding 2 – Lack of Updated External Networks in Next-Day Study Models: When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.	Recommendation 2: TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.
Finding 11 – Lack of Real-Time External Visibility: Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems.	Recommendation 11: TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.

Source: Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations, April 2012. Available at: http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf

BA = Balancing Authority
BPS = Bulk Power System
RC = Reliability Coordinator
RTCA = Real-Time Contingency Analysis
TOP = Transmission Operators
SOL = System Operating Limit

In Finding 2, the joint staff report determined there was a failure to effectively share and coordinate next-day studies within the Western Interconnection. Although the Western WECC reliability coordinator receives some next-day study data, the joint staff report found that there was a need for greater sharing of such data among transmission operators and balancing authorities.

In Finding 11, the joint staff report found that entities lacked sufficient real-time situational awareness of their neighbors. While many transmission operators had the appropriate tools for internal analysis, the joint staff report found that improvements should be made to deal with external contingencies.

The modeling improvements resulting from this stakeholder initiative will also improve the reliability of the ISO grid and market solution accuracy. For the ISO, ensuring reliability and operating efficient markets are inter-dependent. For example, the ISO uses the market to reliably manage congestion on its transmission system and in turn account for transfers and uses of the grid so that we can achieve a reliable and efficient market dispatch. Resources on the ISO grid are dispatched and scheduled through the ISO markets. Only in exceptional circumstances does the ISO dispatch resources outside of its market processes. Therefore, the feasibility and accuracy of the market solution is an important element in the ISO's ability to operate the system reliably. To do this, it is essential we increase the accuracy of our day-ahead and real-time market solutions. As the September 8^{th} event demonstrated, events outside of the ISO can significantly impact the reliability of the ISO grid and market operations. Therefore, the ISO's efforts to improve reliability and market operations encompass improved modeling of our surrounding balancing authority areas and incorporating that information in the market models. This aligns with Finding 2 and Finding 11, and related recommendations, in the joint staff report.

While this initiative seeks to improve modeling of areas external to the ISO, we will in the first instance rely on data that exists with the WECC reliability coordinator. To the extent neighboring entities wish to share more information, we look forward to and appreciate further cooperation.

4 Plan for stakeholder engagement

The proposed schedule for stakeholder engagement is provided below. In April, we brought our initial ideas to the ISO's Market Performance and Planning Forum.[5] Typically we publish an issue paper to discuss the scope of the stakeholder process but since the recommendations in the FERC/NERC joint staff report are clear, the ISO directly published a straw proposal after that presentation. ISO management plans to presents its draft final proposal in this initiative to the Board of Governors at its February meeting for elements of the proposal included in Phase 1. The tariff development process will follow the Board meeting leading to a FERC filing for implementing the Phase 1 elements in Fall 2014. Elements not brought forth to the February meeting will be discussed in a subsequent stakeholder process

[5] See: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForumApr10_2013.pdf

Date	Event
Wed 4/10/13	Presentation at Market Performance and Planning Forum
Tue 6/11/13	Straw proposal posted
Tue 6/18/13	Stakeholder call
Tue 6/25/13	Stakeholder comments due
Wed 9/11/13	Revised straw proposal posted
Wed 9/18/13	Stakeholder in-person meeting
Wed 9/25/13	Stakeholder comments due on revised straw proposal
Wed 10/30/13	Second revised straw proposal posted
Mon 11/4/13	Stakeholder call
Wed 11/13/13	Stakeholder comments due on second revised straw proposal
Thu 12/5/13	Third revised straw proposal posted
Tue 12/10/13	Stakeholder call
Thu 12/19/13	Stakeholder comments due on third revised straw proposal
Mon 12/30/13	Draft final proposal posted
Tue 1/7/14	Stakeholder call
Tue 1/14/14	Stakeholder comments due on draft final proposal
Thu-Fri 2/6-2/7	February Board of Governors meeting for Phase 1

5 Scope of initiative

Given the recommendations in the FERC and NERC joint staff report, the ISO's ultimate goal in this stakeholder initiative is to improve reliability and market solution accuracy. The ISO can achieve this by accurately modeling day-ahead and real-time conditions inside and outside of the ISO to minimize the impact of loop flows. Loop flows can be particularly challenging to manage if they create a significant divergence from day-ahead schedules. Within the WECC, loop flows occur naturally because of the difference between scheduled flows over contract paths and the resultant physical flows that abide by Kirchhoff's circuit laws. However, loop flows can be countered through heightened situational awareness from accurate day-ahead and real-time market solutions. For the ISO, increased awareness and improved modeling can help us decrease the use of exceptional dispatch to manage real-time flows. Improved modeling should also tend to reduce real-time congestion offset charges. This is accomplished by reducing the amount of schedules awarded in the day-ahead market that are infeasible in real-time because of loop flows. These infeasible schedules, including physical schedules and virtual schedules, result in real-time congestion offset because generation on either side of the constraint causing the infeasibility has to be dispatched up in the real-time market at a relatively higher price and dispatched down at a relatively lower price.

To meet our goal and effectuate the recommendations by the joint staff report, the ISO will enhance its full network model (FNM). The FNM is the logical point of change because it provides a detailed and accurate representation of the power system for operational purposes. It contains both physical and commercial data for the reliable and efficient operation of our day-ahead market (including the integrated forward market and residual unit commitment process), the real-time market, and the congestion revenue rights auction and allocation process. The FNM includes:[6]

- ISO physical transmission system reflecting planned outages for each market;
- ISO generation and pumped storage resources reflecting planned outages for each market;
- ISO loads;
- Balancing authority areas embedded or adjacent to ISO;
- Resources external to ISO;
- Resources using dynamic schedules or pseudo-ties;
- Groupings of generation or loads to reflect commercial arrangements; and
- Aggregation of generation or load pricing nodes for bidding and settlement purposes.

Table 2 below lists four major objectives of this stakeholder process and the activities to support them. The objectives and activities seek to address reliability concerns while still respecting each balancing authorities' current operations and processes.

Table 2
Objectives and Activities for Full Network Model Expansion

Objectives	**Activities to support objectives**
• Accurate loop flow modeling • Enhanced security analysis • Better analysis and outage coordination • Accurate high voltage direct current modeling	1. Model external balancing authority area generation, load, and transmission facilities (Phase 1), and scheduling point and hub definitions (Phase 2) 2. Enforce constraints for both scheduled and physical flow (Phase 1) 3. Include variables in high voltage direct current transmission modeling (Phase 1)

Expansion of the FNM will take place in phases, conditioned on the availability of data such as telemetry and outage information, time and resources, and priority. Phase 1 is targeted for implementation by Fall 2014 and includes modeling of: i) the external balancing authority areas involved in the September 8th event; ii) the entities that have signed an EIM agreement to participate in the energy imbalance market when it goes live on October 1, 2014 (PacifiCorp East and PacifiCorp West); and iii) an additional balancing authority area that is highly

[6] See the Full Network Model Business Practice Manual at:
http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Managing%20Full%20Network%20Model

integrated with the EIM entity, Bonneville Power Authority (BPA). If time and data allows, we would like to additionally model Idaho Power, which is integrated with the EIM entity, and Salt River Project, which is integrated with the September 8th entities.[7] The ISO has closely cooperated with the September 8th entities and the EIM entities in data exchanges. This proposal will help the ISO to use this data to accurately account for loop flows and get reasonably accurate state estimator solutions for these areas. The ISO's ultimate goal is to improve the modeling of the entire WECC in later phases. The exact timing and scope of these later phases has not been decided. Selection of additional areas to model may be driven by where unscheduled flows are more significant.

The FNM expansion project is being undertaken to enhance the ISO's modeling of its system. The FNM expansion could be implemented independent of the Energy Imbalance Market (EIM).[8] If the ISO did not create an EIM, it would still pursue this initiative. Also, the policy decisions under each initiative can be considered separately – one for creating an EIM framework and another for addressing ISO's reliability and market efficiency needs. However, improvements provided by the FNM expansion are necessary for reliable modeling of the EIM entities. The FNM expansion will provide improved power flow solutions with greater awareness of external impacts on the combined ISO and EIM entity footprints. This is especially the case for PacifiCorp West, which relies on BPA's transmission system. Therefore, it is critical that Phase 1 of the FNM expansion is implemented in Fall 2014, at the same time as the EIM. Over the last several months, the ISO has worked closely with the EIM Entities to refine and prioritize our modeling needs and we may find that additional BAAs will need to be included.[9] From a process point of view, simultaneously implementing these two initiatives can also provide efficiency gains as they will require changes to similar systems, software, processes, and business practices.

6 Activity 1: model external balancing authority area generation, load, and transmission facilities

To accurately model the loop flow from other balancing authority areas (BAAs), the ISO must first expand the FNM by modeling these BAAs in the day-ahead and real-time markets. Figure 1 below shows the approximate difference between the current and expanded FNM.

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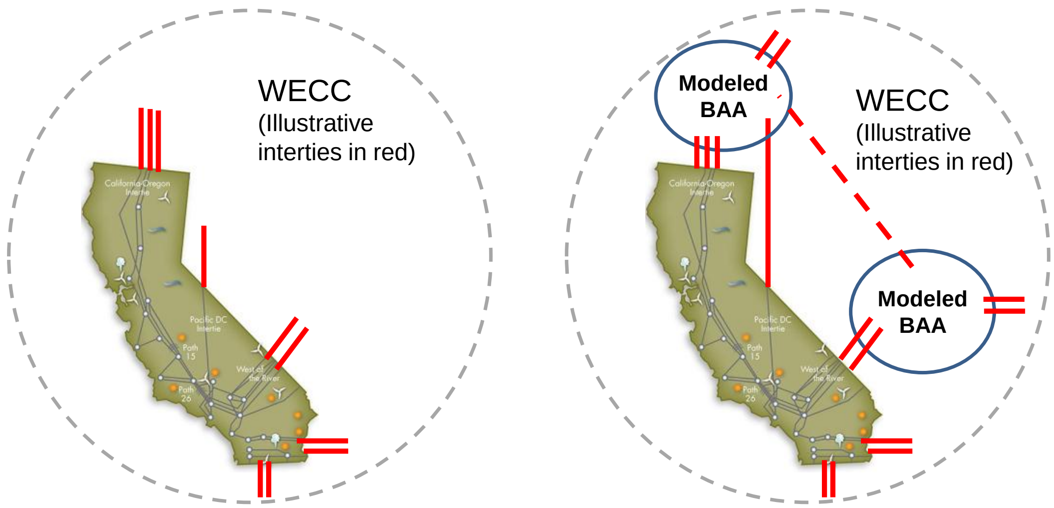
[7] Additional high voltage transmission facilities may need to be added to the market FNM in other neighboring BAAs, to maintain accuracy of power flow calculations, although such areas would not be modeled at the same detail in the initial phase. For example, Nevada has interties with the following: (1) BAAs in Arizona that were affected by the September 8th outage; (2) PacifiCorp; (3) BPA; (4) Idaho Power; and (5) the ISO.

[8] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx

[9] As we have stated in Section 11, the ISO will provide a technical bulletin or similar announcement of the final list of BAAs modeled in the expanded FNM.

Figure 1
Current and expanded full network model



The ISO's scheduling points are currently at the ISO interties, both near the boundary of the ISO's BAA and at more remote scheduling points where the ISO controlled grid extends outside the ISO's BAA. Scheduling points are used by scheduling coordinators to submit physical and virtual bids and schedule energy and ancillary services for imports and exports in the day-ahead and real-time markets. The existing market FNM includes the looped network topology in the Southwest between the scheduling points, although it does not model injections and withdrawal (*i.e.*, sources and sinks) outside the ISO's BAA except for the ISO's market schedules. With the expansion of the FNM to include surrounding BAAs, the ISO proposes to model external systems in the FNM to include non-ISO injections and withdrawals as well as the transmission topology in additional areas. Table 3 below summarizes the changes.

Table 3
Current and proposed modeling, scheduling and pricing

Current		**Full Network Model Expansion Proposals**	
Modeling, scheduling and pricing		**Modeling**	**Scheduling and pricing**
Scheduling points at the ISO interties; systems outside of ISO only partially modeled	Phase 1	• External generation , and load not involving ISO market transactions, as well as external transmission facilities will be modeled at external balancing authority areas • ISO imports/exports will be modeled at existing intertie scheduling points.	• Remains at the current scheduling points at the interties unless an interchange scheduling agreement is signed

6.1 Data for modeling the base schedules

The ISO will model for each BAA a base schedule which is comprised of the demand, generation, and scheduled net interchange of that BAA. The ISO proposes to create these base schedules because they will reflect energy flows in the WECC resulting from energy schedules not involving the ISO. These schedules are important to model because they create physical flow impacts on the ISO system. To the extent possible and as a default option, the ISO will rely on existing data sources such as the WECC region's Reliability Coordinator (Peak Reliability), the WECC Interchange Tool, and available historical data from the ISO's state estimator. However, this may not be sufficient data to directly use to model the BAAs accurately. Therefore, the ISO welcomes balancing authorizes to provide and/or share data with the ISO to improve the collective modeling. This can be achieved through a voluntary agreement to be developed at a later point (potentially outside of the scope of this policy stakeholder process). The ISO will use the best available data and can use its own analyses to develop or modify base schedules if and when necessary.

The following six data sets represent our priority list for FNM expansion:

1. Telemetry
2. Load and generation distribution factors
3. Demand forecasts
4. Net interchange schedules
5. Generation forecasts
6. Generation and transmission outages

In the list above both telemetry and load and generation distribution factors will be based on the ISO's state estimator. For example, the default generation and load distribution factors will be adapted from the state estimator solution and maintained in an electronic library for various seasons, day types (e.g., workday, weekday/holiday), and day periods (e.g., on-peak, off-peak), and normalized for known outages. Demand forecasts can be provided by the Reliability Coordinator. In addition to daily updates, the Reliability Coordinator will also have demand forecasts for the next several days for each BAA so there should consistently be data available to pull by the ISO. Nonetheless the ISO will rely on its own analysis and validation, for example, to true up or estimate missing information. In addition, compared to a historical analysis of actual demand, the ISO can further fine tune the demand forecasts if needed by scaling the forecast up or down. The net interchange schedules can be pulled via the WECC Interchange Tool, which provides information by tie for each BAA. The ISO can use this data source as a starting point and as we collect more information, we can compare the completeness of this data at different reporting times. This can be accomplished via an historical statistical analysis such as a regression technique to create the best available modeling input by scaling or estimating the expected interchange levels. We discuss the difference in reporting times in greater detail below. Since generation in a BAA must equal the sum of demand and net schedule interchange, the generation can be derived from this simple equation.[10] Lastly, generation and transmission outages reported to the Reliability Coordinator or known to the ISO can be included in the base schedule modeling. For all of the data points listed above, BAAs can also directly provide the information to the ISO.

Another area that will require ISO estimation is the discrepancy between data submission deadlines at the Reliability Coordinator at noon and the start of the ISO's day-ahead market at 10 a.m. Since the Reliability Coordinator will not have a complete data set available by 10 a.m., the ISO will estimate schedules based on historical supply/demand schedules obtained from a saved power flow solution with supply, demand, and any known or historical net interchange. Once the data is obtained, the ISO can create base schedules for each BAA by distributing the demand, net of tagged scheduled intertie transactions, to supply resources in each BAA using generation distribution factors, normalized for known outages. Similarly, the ISO will derive base schedules in the real-time market in a similar fashion for future intervals beyond the next trading hour. However, by 3 p.m. when the ISO is ready to pull the data again in preparation for the real-time market, the Reliability Coordinator will have data from all of the balancing authorities based on its 10 a.m. deadline.[11] Alternatively, the ISO can use more accurate

[10] For example, if a BAA has 10,000 MW of native demand and 500 MW of net export, then its native generation must be 10,500 MW in order to meet demand and support the energy export.

[11] The deadline for reporting to the Reliability Coordinator is 10 a.m. prevailing Pacific time. However, this data may not be available to the ISO in time to incorporate into the day-ahead market. To the extent it is, we may use it. If not, we can rely on the methodology described above. The reporting requirement is created by the WECC Reliability Coordinator pursuant to NERC Reliability Standard IRO-010-1a. See the data request from the WECC Reliability Coordinator available at: http://www.wecc.biz/awareness/Reliability/Documents/WECC%20RC%20Data%20Request%20Specification.pdf

information for the current trading hour from the state estimator solution for these areas. If data is provided directly from a BAA, that information can be used for both day-ahead and real-time.

While the ISO intends to leverage the data made available by the Reliability Coordinator, we will also reserve the right to create, modify, or select amongst different data sources as appropriate. Under the most drastic scenario, the base schedules can be "set" to zero, which would be similar to our current FNM without base schedule modeling. To do this, we may adjust the net schedule interchange up or down to better match the amount of unscheduled loop flow that affects the ISO system. As described in the benchmarking analysis in Section 11, the ISO will be tracking the difference between scheduled and actual flows to understand whether or not the base schedules are effective. Based on these results, the ISO can calibrate the net scheduled interchange. In a more extreme approach, all of the base schedule (demand, generation, and net scheduled interchange) can be set to zero. This would occur in the most extreme scenario because it would likely decrease the accuracy of the market solutions for the EIM entities. Given these two options to "set" the base schedules, we believe this is a good starting point for our proposal and the ISO can learn from the outcome of this modeling methodology. The ISO will have the flexibility to further refine and adjust this methodology as we gain more experience with the expanded FNM. As explained in Section 11, the ISO intends to test for the accuracy of the base schedule modeling before implementation.

6.2 Methodology for modeling the base schedules

The ISO intends to model the networks and base schedules of all of the BAAs in the WECC so that our modeling can reflect as much of the unscheduled loop flows as possible. However, modeling the networks can be very data intensive and needs to be developed in phases with sufficient time and resources. As noted in Section 5, Phase 1's priority is the full modeling of the September 8th entities and those BAAs needed for accurate modeling of the EIM entities. To the extent time and resources allow, we can model additional BAAs. Either way, Phase 1 implementation will result in modeled and non-modeled BAAs. For external BAAs that are modeled in the FNM, the ISO will define generation aggregation points comprised of the generation distribution factors reflecting all supply resources in the respective BAAs. For load, each modeled BAA will have defined a load aggregation point and, similar to generation, the ISO can use historical load patterns to develop default load distribution factors to distribute the demand forecast throughout the BAA.

For external BAAs that are <u>not</u> modeled in the FNM, the ISO will define a boundary point at the FNM boundary at each intertie with these external BAAs. These boundary points, similar to the existing scheduling points at the ISO interties, will be eventually replaced with the relevant generation and load aggregation points after these external BAAs are included in the FNM.[12] In the interim, these boundary points will be modeled as injections and withdrawals to a single point.

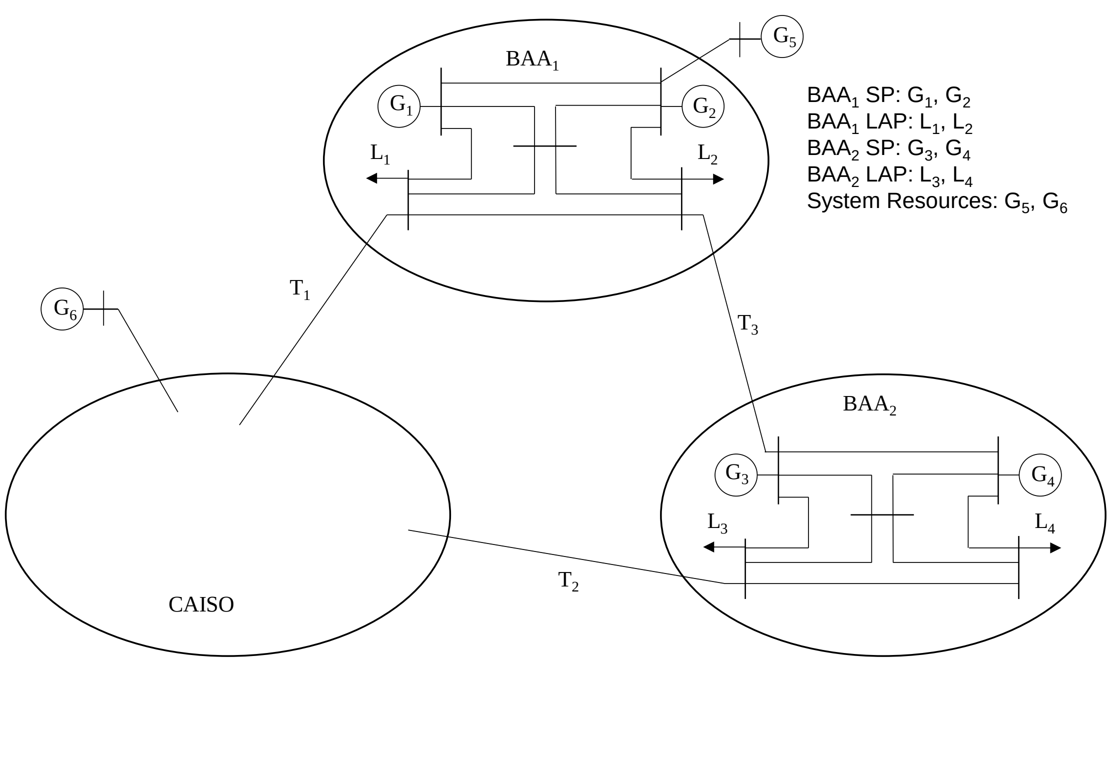
[12] If the FNM encompasses the entire WECC, there would be no need for these boundary points or the associated generic system resources.

Figure 2 below shows a simplified example of FNM expansion. The ISO is shown in the lower left and it is connected to two modeled balancing authority areas (BAA_1 and BAA_2). There is a generation aggregation point composed of generators G_1 and G_2 for BAA_1. Similarly, there is a generation aggregation point composed of G_3 and G_4 for BAA_2. A load aggregation point composed of loads L_1 and L_2 is defined for BAA_1, and a load aggregation point composed of L_3 and L_4 is defined for BAA_2.

Under Phase 1, the demand forecast of each balancing authority area is distributed to the loads in the respective load aggregation point using default load distribution factors. Consequently BAA_1's load is allocated to L_1 and L_2 using load distribution factors the ISO developed for BAA_1 and BAA_2's load is allocated to L_3 and L_4 using load distribution factors the ISO developed for BAA_2. The example also shows two system resources G_5 and G_6, where G_5 is connected to the FNM through an intertie with BAA_1. These resources are used to model compensating injections from/to external BAAs to represent BAAs that have not yet been modeled in the FNM. These are FNM boundary points. The FNM boundary points will be used in the base schedule modeling effort to model exchanges with non-modeled, non-ISO BAAs to reflect unscheduled loop flows through the ISO.

In Section 10.1 we use this model as the foundation for numeric examples that step through how base schedules are developed (to be implemented in Phase 1).

Figure 2
FNM Expansion Modeling Example



With these elements defined within the FNM, the ISO will be able to get a much more accurate power flow solution based on day-ahead schedules and real-time dispatch starting with Phase 1.

6.3 Impact of base schedules and separate treatment for COI

Base schedules will be reflected as fixed schedules in the market optimization software under both Phase 1 and 2 (but to be implemented with Phase 1). Some stakeholders have voiced a concern that assuming all base schedules as fixed within the optimization "solves" other BAAs' unscheduled flow problems. The central premise of the ISO's proposal to model base flows, as it relates to reducing real-time congestion uplift costs, is to protect the ISO market against establishing schedules in the day-ahead market, and these schedules' associated financial entitlements, that exceed the transfer capability that is likely to be available in real-time. While this entails accommodating other BAAs' loop flow in the day-ahead market, the alternative is for the ISO market to be left with the costs of re-dispatch to accommodate this unscheduled flow in real-time. If real-time unscheduled flows are less than expected, the ISO will dispatch generation up above the day-ahead market schedules and generate congestion rent surpluses that will offset the days when it underestimates loop flows. It is also very important to note that other BAAs are affected by the ISO's unscheduled flows and will similarly need to redispatch units to accommodate these flows in most instances.

Some stakeholders have also voiced a concern that assuming all base schedules as fixed within the optimization is contrary to current WECC region practices for managing unscheduled flows. This is incorrect. First, WECC's agreement to provide relief for unscheduled flow stems from WECC standard IRO-006-WECC-1, which allows for relief only on qualified transfer paths to the extent that flows exceed or are anticipated to exceed limits.[13] In all other instances, the WECC procedure requires 100% accommodation of unscheduled flow. There are six qualified transfer paths and the ISO is a path operator for only one, Path 66 (COI).[14] The WECC standard does not apply to ISO internal transmission constraints, which the FNM expansion proposal will address and is likely contributing the most to the real-time congestion imbalance offset costs. In the prescribed methods available to path operators to manage flows through WECC's procedure when scheduled and unscheduled flows exceed the transfer capability of a qualified transfer path, curtailment of schedules is only one of the approved methods and only occurs *after* the use of phase shifters and accommodating unscheduled flows has occurred up to a certain percent.[15] The current WECC procedures have been reaffirmed by the FERC in a

[13] http://www.nerc.com/files/IRO-006-WECC-1.pdf

[14] http://www.wecc.biz/committees/StandingCommittees/OC/UFAS/Shared%20Documents/USF%20Qualified%20Path%20Listing.pdf

[15] http://www.wecc.biz/committees/standingcommittees/oc/ufas/shared%20documents/ufas%20mitigation%20plan.pdf; see Attachment 1.

recent order on the subject.[16] For other interties, the ISO is solely responsible for accommodating schedule adjustments. As noted above, other BAAs are affected by the ISO's unscheduled flows and unless the flows are on one of the qualified paths, these BAAs also provide 100% accommodation.

For COI only (and the Pacific AC Intertie (PACI), which is the major portion of COI that is within the ISO's market area), we can adjust our approach by not enforcing the *proxy* flow limit in the day-ahead market. Instead, we will enforce the *actual physical flow limits of COI's underlying system* and the scheduling limit in the day-ahead market, which is what we do today. In other words, this separate treatment will not change our existing practice with regard to steady state limits and allows us to extend the current practice for paths where the ISO has sole responsibility for flow management in the real-time to the day-ahead. This separate treatment of COI is reinforced by the confluence of three factors: 1) enforcement of physical and scheduling constraints in the FNM; 2) the availability of WECC's unscheduled flow mitigation procedure for COI; and 3) recognition that the proxy flow limits on COI do not accurately reflect a physical limit.[17] The separate treatment for COI addresses stakeholders' comments regarding adherence to WECC practices. As described in Section 7, one of the activities for the FNM expansion initiative is to enforce both the scheduled and physical flow constraints. But as noted above, ISO can take advantage of WECC's unscheduled flow mitigation procedure for COI in real-time so that would allow the ISO to not enforce the proxy flow limit in the day-ahead. Instead, the ISO would only enforce the scheduling limit and the actual physical flow limits of COI's underlying system. If the proxy flow limit were enforced on COI in the day-ahead, it would reduce all schedules in our market and basically function as 100% accommodation. On the other hand, the separate treatment for COI will allow the ISO to use the WECC procedure by accommodating up to the specified percentages, using phase shifters, and then curtailing ISO market schedules as well as off-path schedules that contribute to COI flow but are outside of the ISO market. There are established WECC rules for cost allocation of phase shifter use which the ISO already participates in and we should not ignore the value they provide. For other interties besides COI, we are responsible for 100% accommodation of loop flow in real-time, and enforcing the flow limits in the day-ahead makes our day-ahead and real-time processes more consistent.

WECC's Path Operator Task Force recognizes that the flow capacities of the lines comprising Path 66 itself are not the actual limit (being, in fact, much greater than the path limit) and instead are essentially a proxy for the real transmission limits.[18] Previously, the COI rating has been

[16] See Federal Energy Regulatory Commission Docket No. EL13-11-000, "Order Denying Compliant," issued February 1, 2013.

[17] This proposal also continues the existing consistency between constraints enforced in the day-ahead and real-time markets. In real-time, the ISO manages its portion of physical flows on COI using nomograms on transmission within the ISO controlled grid, and monitors real-time flows across COI as part of the WECC unscheduled flow mitigation plan, which is a non-market mechanism, rather than using market dispatches to manage the COI path rating. The ISO uses the same nomograms near COI in the day-ahead and real-time markets, and will continue to do so.

[18] See http://www.wecc.biz/committees/StandingCommittees/JGC/POTF/Documents/Forms/AllItems.aspx.

used as a proxy limit that represented findings from off-line studies using assumed conditions. With access now to more modern reliability assessment tools, the Path Operator Task Force has observed that the result of enforcing the path rating as a flow limit, instead of modeling the actual underlying constraints, has been both the reduction of schedules when no reliability condition actually existed, and reliability risks at lower flow levels than the proxy limit. The actual transmission constraints include limits within the ISO's BAA, and have been represented by nomograms with factors such as Northern California hydro output that are taken as fixed inputs rather than being optimized against imports across COI and PACI. The modeling improvements provided by the FNM expansion will now allow the underlying limits to be directly modeled, thus eliminating the need for the proxy limit. This treatment for COI will also bring us in line with how the BPA treats COI.[19] BPA enforces several flow-based limits for scheduling within its BAA, but does not enforce a flow limit on COI in the day-ahead timeframe. Instead, BPA manages its side of COI using the scheduling limit, which the ISO will continue to use in both day-ahead and real-time. Lastly, the Second Amended COI Path Operating Agreement "requires unscheduled flow to be deducted from Operational Transfer Capability Limit and Available transfer Capability only on a real-time basis, or for the hour-ahead pre-scheduling period" unless an alternative procedure is established.[20] Our proposed approach is line with this agreement.

In summary, the ISO proposes to use the unscheduled flow mitigation procedure to curtail schedules in the real-time beyond our required minimum accommodation percentage. The ISO would still enforce the scheduling limit on PACI and both the scheduling and physical flow limits in the day-ahead market for other interties that are not WECC qualified paths, where the flow limits are typically equal to the intertie line's thermal capacity and where the ISO is currently required to provide 100% accommodation of unscheduled flow rather than being able to use WECC's unscheduled flow mitigation plan.

As is currently the case, the ISO will adhere to FERC's ruling that losses will not be double-charged on specific imports and exports from the existing IBAA users that demonstrate they pay Transmission Agency of Northern California or the Western Area Power Administration for losses.

For the future, the WECC has proposed to evaluate schedule curtailment based on transmission priority in a new Unscheduled Flow Reduction Guideline. However, a recent memo from WECC notes that the FERC has expressed some concerns with WECC's proposal.[21] WECC staff considered four options ranging from: (1) a full filing at the FERC for the proposed guideline with transmission priority curtailment; (2) modifications to the guideline and file; (3) file the guideline

[19] See Appendix 3 in WECC Path Concept White Paper, September 20, 2013.
http://www.wecc.biz/committees/StandingCommittees/PCC/Lists/Team%20Discussion/Attachments/88/PathCpnceptWhitepaper_clean_draft_2013-09-20_V0.pdf
[20] Second Amended COI Path Operating Agreement, Section 8.2.
[21] WECC Staff memo to WECC Operating Committee, "Unscheduled Flow Reduction Guideline Filing Discussion," April 5, 2013, p. 1.
http://www.wecc.biz/committees/StandingCommittees/OC/20130423/Lists/Minutes/1/UFMP%20Memo%20on%20Options.pdf

as information only; or (4) not file at all. WECC decided to file the guideline as informational only.[22] In addition, WECC is also working on an Enhanced Curtailment Calculator, which has not yet been finalized or approved by FERC.

Given this regulatory uncertainty, we propose to move forward with the FNM proposal to model base schedules as fixed schedules in the market optimization. The ISO is an active participant in WECC discussions. If and when these new procedures are implemented and approved by FERC, the ISO could potentially make adjustments to the base schedule methodology to reflect that portion of unscheduled flow that could be reduced through the WECC procedures.

6.4 Modeling imports and exports and Transaction IDs

As discussed at the September 18th stakeholder meeting, the current scheduling points at the interties do not reflect where generation is actually located. In other words, the current FNM represents imports as if generation is increasing at the interties when in fact there may not be any generators located there. This is the case for Victorville, as discussed at the meeting. Under Phase 1, the ISO will continue to reflect cleared bids at the current scheduling points at the interties. The result of this modeling simplification is a decrease in the accuracy of the physical flow impact of these schedules. In other words, the ISO may assume more energy is flowing over specific interties where in reality the physical flow is more dispersed and therefore causes more unscheduled loop flow for the ISO and other BAAs in WECC.[23]

The remainder of this section will discuss the treatment of dynamic and static (*i.e.,* non-dynamic resource) bids in Phase 1 of the expanded FNM. Dynamic resources can exist within a modeled BAA or at the FNM boundary, are supported by resource-specific operating data (schedules, metering, telemetry, outage reporting, etc.), and will continue to be modeled and priced at resource-specific locations. A dynamic resource is registered with the ISO and assigned a unique resource ID registered in the ISO's Master File; it is modeled with the same level of detail, telemetry, and revenue quality meter requirements as internal generating resources. Dynamic resources may participate in the day-ahead market, as well as in the 15-minute and 5-minute real-time markets. Static intertie bids[24] may be submitted in the day-ahead market, as well as in the 15-minute real-time market, but they may not participate in the 5-minute real-time market. Static intertie bids are submitted at the current scheduling points at the interties under Phase 1.[25] FNM boundary points will not be used for scheduling. Unlike dynamic resources, static intertie bids or schedules are not associated with a specific resource

[22] http://www.wecc.biz/committees/StandingCommittees/OC/071513/Lists/Minutes/1/UFAS%20Report%20July%202013.pdf

[23] Under Phase 2, the ISO proposes to eliminate this simplifying assumption by modeling bids for imports to and exports from the ISO as originating from generators or sinks in the WECC. See Appendix 1: Phase 2 proposal for a detailed discussion.

[24] Meaning not dynamically scheduled.

[25] The ISO proposes in Phase 2 to create scheduling hubs and the Location ID would instead be used for the selected scheduling hub or other configuration based on an executed interchange scheduling agreement, EIM entity, or other agreement. See Appendix 1: Phase 2 proposal for a detailed discussion.

and are not required to have a resource ID registered in the Master File. Table 4 below summarizes the general approach to modeling types of import/export bids in the ISO markets.

Table 4
General approach to modeling intertie bids

- Intertie bids from dynamic resources are modeled at detailed registered resources with unique resource IDs
- Static intertie bids are modeled at the relevant current scheduling point at the intertie (under Phase 1)

Exceptions to the above include the EIM entities and those resources under a Market Efficiency Enhancement Agreement or an interchange scheduling agreement. The EIM entities will be modeled as hubs in the day-ahead so day-ahead intertie bids with the EIM entity will need to specify the EIM entity scheduling hub. In real-time, the EIM agreement provides the ISO with detailed modeling information so that we can provide scheduling and pricing at a nodal level. For integrated BAA entities that have signed a Market Efficiency Enhancement Agreement (MEEA), those resources will receive more granular pricing that the current integrated BAA import (Captain Jack) and export (SMUD Hub) points.

As part of this proposal, the ISO will also provide the opportunity for interested parties to provide more generation modeling data in order to receive more accurate and granular pricing. If the data is detailed enough, the ISO can provide pricing that reflects actual resource locations rather than the intertie points. There is precedent in the ISO market for such an agreement in the MEEA. MEEAs are currently only offered to IBAAs but this framework can be extended to other WECC entities, potentially with some appropriate modifications. See ISO tariff Sections 27.5.3.2 through 27.5.3.7 for the current information required to develop a MEEA (noting that this is only offered for IBAAs at the moment). The ISO proposes to develop such an interchange scheduling agreement or dynamic transfer agreement with interested and affected parties. Another alternative is available for EIM entities, which provide detailed generation data and receive nodal real-time pricing in return.

Real-time compensating injections may be needed to reflect schedules not otherwise modeled. Compensating injections are injections and withdrawals that are added to the network model at locations external to the ISO system. Currently they are used to minimize the difference between the actual flows on interties and the scheduled flows. In the FNM they will be used to minimize the difference between the actual flows and modeled flows. While compensating injections may not decrease overall with the FNM expansion, we expect this initiative to increase the overall accuracy of our model solutions. Therefore, compensating injections may be used more effectively.

Since resource IDs will not be required for static intertie bids, the ISO proposes to use a “transaction ID” that will serve as a surrogate resource ID in order to uniquely identify these bids and any resultant schedules. Table 5 below shows the bid information that will be included in the transaction ID. Unlike the resource ID, the transaction ID will not be registered in the Master File, but it will be generated when bids are submitted and will persist through the ISO market systems, from bid validation through market clearing and settlements. The transaction ID will help the ISO identify bids and schedules, honor contract paths by enforcing scheduling limits, and facilitate intertie schedule tagging of physical bids and intertie referencing for virtual bids, without the need to register an unbounded number of resources in the Master File. Furthermore, the use of a transaction ID as the main means of bid and schedule identification will present a minimal change to market participants' existing systems since it can simply replace the existing resource ID. For Phase 1, the location ID is the scheduling point name which is currently the scheduling points at the intertie.[26] As part of the transaction ID, the Scheduling Coordinator can provide an integer-based numeric ID. This numeric ID can persist through the system and can be used over and over to help the Scheduling Coordinator identify bids. The length of the numeric ID will be determined during the implementation phase. The transaction ID will be specified in the OASIS field on e-tags. Specifically for wheeling transactions, the counterpart transaction ID will be specified in the optional WECC field on e-tags.

Table 5
Transaction ID details

Category	Detail
Scheduling Coordinator ID	Same as today
Location ID	Scheduling Point (under Phase 1)
Primary Intertie ID	Used for schedule tagging and scheduling limit constraints
Alternate Intertie ID	Used for schedule tagging and scheduling limit constraints when the primary intertie is open and the Scheduling Coordinator has alternate scheduling agreement (dynamic transfer)
Bid Type	Physical or virtual, supply (import) or demand (export), firm/non-firm, wheeling, etc.
Counterpart transaction ID	For wheel through transactions only
Numeric ID	Integer-based ID provided by Scheduling Coordinator to help identify bid

[26] The ISO proposes in Phase 2 to create scheduling hubs and the Location ID would instead be used for the selected scheduling hub or other configuration based on an executed interchange scheduling agreement, EIM entity, or other agreement. See Appendix 1: Phase 2 proposal for a detailed discussion.

As an exception, for static intertie bids associated with resource adequacy capacity, existing transmission contracts, transmission ownership rights, ancillary services certification, or other contractual agreements, it will still be necessary to set-up a resource ID in the Master File to link these bids to their respective contract information. For all resources registered in the Master File, the transaction ID will be the respective resource ID.

7 Activity 2: enforce constraints for both scheduled and physical flow

As mentioned above, WECC entities use both scheduled and physical flows. The ISO proposal under this initiative is to use a dual approach that will respect both scheduled and physical flows. This, in conjunction with improved modeling of day-ahead and real-time conditions, will help to minimize and manage unscheduled loop flows.

This initiative conforms with the dual constraint methodology with that proposed as a result of the FERC Order 764 stakeholder initiative.[27] Table 6 summarizes the dual constraint methodology under FERC Order 764 market changes, which will allow virtual bids to provide counterflow for contract path limits in the integrated forward market run. This will result in consistent pricing for both physical and virtual awards. During residual unit commitment, the optimization will consider physical awards only with respect to contract path limits. Under the FERC Order 764 market design, only these physical awards that also clear the residual unit commitment process will be allowed to be tagged prior to the fifteen minute market, ensuring that tagged schedules do not exceed an intertie's capacity. The dual constraint methodology is not relevant to the real-time market as the real-time market does not consider virtual bids.

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

Table 6
FERC Order 764 and Full Network Model Expansion dual constraint methodology

	FERC Order 764 terminology and explanation	Full Network Model terminology and explanation
Integrated forward market	Not enforce physical only constraint – in other words, allow virtual bids to provide counterflow for contract path limits ➢ Impact: physical and virtual awards will have the same price	Revised straw proposal (9/11): • Scheduling constraint – considers physical bids only; does not allow virtual bids to provide counterflow for contract path limits • Physical flow constraint – considers both physical and virtual bids ➢ Impact: physical and virtual awards may have different prices – differs from FERC Order 764 market changes **Second revised straw proposal (10/30):** • Scheduling constraint – considers both physical and virtual bids • Physical flow constraint - considers both physical and virtual bids ➢ Impact: physical and virtual awards will have the same price – same as FERC Order 764 market changes
Residual Unit Commitment	Enforce physical only constraint – only consider physical awards with respect to contract path limits (*i.e.*, virtual awards cannot provide counterflow to physical awards). This determines which physical imports cleared in IFM for which the ISO will accept e-tags prior to the fifteen minute market.	Same as FERC Order 764 and no changes from previous proposal
Real-time market	Only physical schedules are considered by real-time market.	Same as FERC Order 764 and no changes from previous proposal

The ISO proposes to enforce two constraints on each ISO intertie in the day-ahead market and each EIM intertie in the real-time market to manage transmission congestion.

The **first is a scheduling constraint based on the intertie declared** in intertie bids against the operational limit of the intertie. This will ensure that contract paths are honored and will be used for tagging intertie schedules. In enforcing the constraint, the ISO will net physical and virtual import and export energy schedules against each other during the integrated forward market run, as described above in Table 6. The entire schedule or award will be constrained (*i.e.*, no shift factors). During residual unit commitment, only physical import/export energy schedules will be considered.[28] Ancillary services, on the other hand, because they require firm transmission and would not be simultaneously dispatched for energy in both directions, will not be netted. For example, a regulation down (export capacity) will not net against upward ancillary services (import capacity). Furthermore, transmission capacity reserved for ancillary services awards will not create counter flow transmission capacity for energy schedules. These scheduling limit constraints will not be different than the constraints that are currently enforced on ISO interties.

The **second is a physical flow constraint based on the modeled flows** for an intertie taking into account the actual power flow contributions from all resource schedules in the FNM against the operational limit of the intertie. The operational limit per intertie is the same in both scheduling and physical constraints. This second constraint includes both physical and virtual import/export energy schedules in the integrated forward market. Only physical import/export energy schedules are considered in the residual unit commitment process and the real-time market. This is consistent with the ISO's implementation of FERC Order 764 where virtual intertie schedules are only considered in the integrated forward market and only the physical intertie schedules that clear the residual unit commitment are allowed to submit tags prior to the fifteen minute market. Unlike the scheduling limit, the schedule contributions toward the physical flow limit will be based on the power transfer distribution factors (*i.e.* shift factors) calculated from the network topology so that we can accurately model loop flows. Refer to Section 10.2 for an illustrative numeric example of how the two constraints are enforced.

The scheduling and physical flow limit constraints collapse to the same constraint in the case of some radial interties in the current FNM, where the power transfer distribution factors are all 1 or 0 for these interties, but they need to be differentiated in the expanded FNM.

8 Activity 3: include variables in high voltage direct current transmission modeling

The ISO currently models the Trans Bay Cable high voltage direct current (HVDC) transmission line in the FNM. Since the line is internal to the ISO, the modeling is simplified so that the load at the rectifier station is equal to the generation at the inverter station, using logical resources at each converter station. Furthermore, that load and generation are fixed in the market. Under Phase 1, the ISO proposes to enhance its current model for HVDC transmission for those lines for which the ISO has and does not have direct operational control. We discuss each scenario.

For HVDC links where the ISO has direct operational control (*e.g.*, Trans Bay Cable), the ISO proposes to replace the fixed algebraic injections at the converter stations with free variables (*i.e.*, without a cost in the objective function). The ISO would no longer fix the two power injections, but will still constrain them to be equal to each other by enforcing a balancing

[28] More specifically, the residual unit commitment does not award additional exports but rather considers the exports awarded by the integrated forward market. The residual unit commitment can award additional imports.

constraint. As an additional measure of accuracy, the ISO can even approximate the associated DC losses in that balancing constraint. Furthermore, the magnitude of the algebraic power injections would be limited by the HVDC link's capacity allowing omnidirectional power flow.

For HVDC links where the ISO does not have direct operational control (*e.g.*, Pacific DC Intertie, InterMountain-Adelanto), the ISO proposes a similar model with algebraic injection variables at the converter stations constrained by a balancing constraint. However, in these cases the injections will be limited by the algebraic sum of all associated import and export schedules that declare the use of the HVDC link in the corresponding bids. Furthermore, the injections will be limited by applicable transmission rights. Verified tags for intertie schedules on the HVDC links would provide a hedge for the locational marginal price difference between the inverter and rectifier stations, in effect exempting these schedules from marginal loss and marginal congestion charges between these stations since the associated energy is flowing on the HVDC link as opposed to the AC network. Refer to Section 0 for an illustrative example.

9 Congestion revenue rights

Holders of monthly, seasonal, and long term congestion revenue rights (CRRs) with a source or sink at the interties will be impacted by the FNM expansion. Enhancements to the FNM that are incorporated into the running of the day-ahead market will be evaluated to determine how best to incorporate it into the development of the CRR FNM. One of the key principles behind maintaining revenue adequacy through the CRR allocation and auction processes is to mimic, as much as possible, the same FNM as utilized in the day-ahead market. To maintain this principle the CRR FNM will follow the objectives and activities as noted in Table 2.

9.1 Loop flow modeling

As part of the FNM expansion project one of the objectives will be to model loop flows in the day-ahead market. In the CRR model we propose to model similar "base schedules" as utilized in the day-ahead market with the exception that the CRR model will need to develop these base schedules on a monthly/TOU basis. As noted further in this section the modeling of loop flow in the CRR process will initially be done in the monthly CRR process only and can be revisited after the first year of operation to determine whether modeling loop flow in the monthly CRR processes is sufficient. The base schedules would be modeled as fixed injections and withdrawals as CRR Options. We will conservatively reflect the base schedules as CRR options at implementation of this first phase of the FNM expansion. Over time and with sufficient analysis, the ISO may reflect the base schedules as CRR options and/or obligations. The application of these base schedules into the CRR process will have some timing and possible CRR simultaneous feasibility test impacts that need to be considered since the 2015 annual allocation and auction markets will already have been completed when the expanded FNM is implemented. The first available CRR process will likely be the monthly allocation and auction period. Note that even for the monthly CRR, the typical monthly CRR process starts approximately 30-45 days prior to the first operating day of the month. After further discussion it was determined that modeling of loop flow would only be applied during the monthly process and the application of the break-even methodology[29] would be applied in the annual process, which would eventually capture the modeled loop flow from the day-ahead market. In other words, as history is developed from the day-ahead market, the capacity available to fund CRRs in the day-ahead market would be adjusted for the loop flow modeling and as such should be reflected in the break-even methodology.

By including base schedules it is possible, though unlikely, that the existing CRRs might not clear the CRR simultaneous feasibility test. We expect the CRRs to clear the test because the annual CRR process only releases 75% of system capacity, and any shifting of flows across the inter-ties should not exceed the difference between the annual release amount and the monthly release capacity. If that situation arises the ISO will perform limit expansion, as is currently done for any previously awarded CRRs that do not clear the CRR simultaneous feasibility test due to modeling differences between when the CRRs were awarded and the running of a subsequent CRR allocation or auction market. This is described in Section 36.4.2 in the tariff.

CRR "clawback" rules such as those in Section 11.2.4.6 and 11.2.4.7 in the tariff will still apply.

10 Examples

This section provides three illustrative examples of the market clearing process that will use the expanded FNM. The first example will show how the ISO determines base schedules for each BAA prior to the day-ahead and real-time market run as will be implemented in Phase 1. It then provides a brief illustration of how import and export schedules are cleared today building the foundation for the next example. The second example explains how both scheduled and physical constraints are enforced as will be implemented in Phase 1. Finally, the third example is about the HVDC modeling improvement that will be implemented in Phase 1. See also Appendix 1: Phase 2 proposal for the same examples recalculated under the Phase 2 proposed changes.

10.1 Example 1: creating base schedules

This example first describes how the base schedules are created. This process involves distributing the demand forecast for each balancing authority area to load nodes using the respective default load distribution factors. Similarly, the demand forecast net of any scheduled interchanges (e.g., day-ahead schedules with the ISO or other balancing authority areas, prior to the real-time market) will be distributed to the resources in each balancing authority area based on historical generation patterns using generation distribution factors, or based on the

[29] See http://www.caiso.com/Documents/RevisedDraftFinalProposal-CongestionRevenueRights2011Enhancements.pdf.

state estimator solution in the real-time market. The base schedule determination will include information about resource and transmission outages and other relevant data to the extent they are available. In the real-time market, the base schedules for the ISO are the day-ahead schedules.

The ISO will then run an AC power flow with net interchange control for each BAA to maintain its net schedule interchange. A distributed load slack will be used to distribute transmission losses in each balancing authority area. The resultant adjusted base schedules will be used as a reference in the subsequent market run.[30]

The ISO will then run its market performing congestion management for the ISO network and ISO interties.[31] The ISO market solution will ignore the impact of transmission losses in external balancing authority areas on the locational marginal prices.[32]

10.1.1 Establishing the base schedule

Figure 3 shows the CAISO and two modeled external balancing authority areas: BAA_1 and BAA_2. BAA_1 has a generation aggregation point composed of G_1 and G_2 and a load aggregation point composed of L_1 and L_2. BAA_2 has a generation aggregation point composed of G_3 and G_4 and a load aggregation point composed of L_3 and L_4.

[30] The process for determining and calculating adjusted base schedules is slightly different for EIM Entity BAAs in the RTM and it is described in detail in the EIM straw proposal.
[31] Congestion management is also applicable to EIM Entity BAAs in the RTM.
[32] With the exception of EIM Entity BAAs in the real-time market.

Figure 3
Modeled BAAs in the full network model

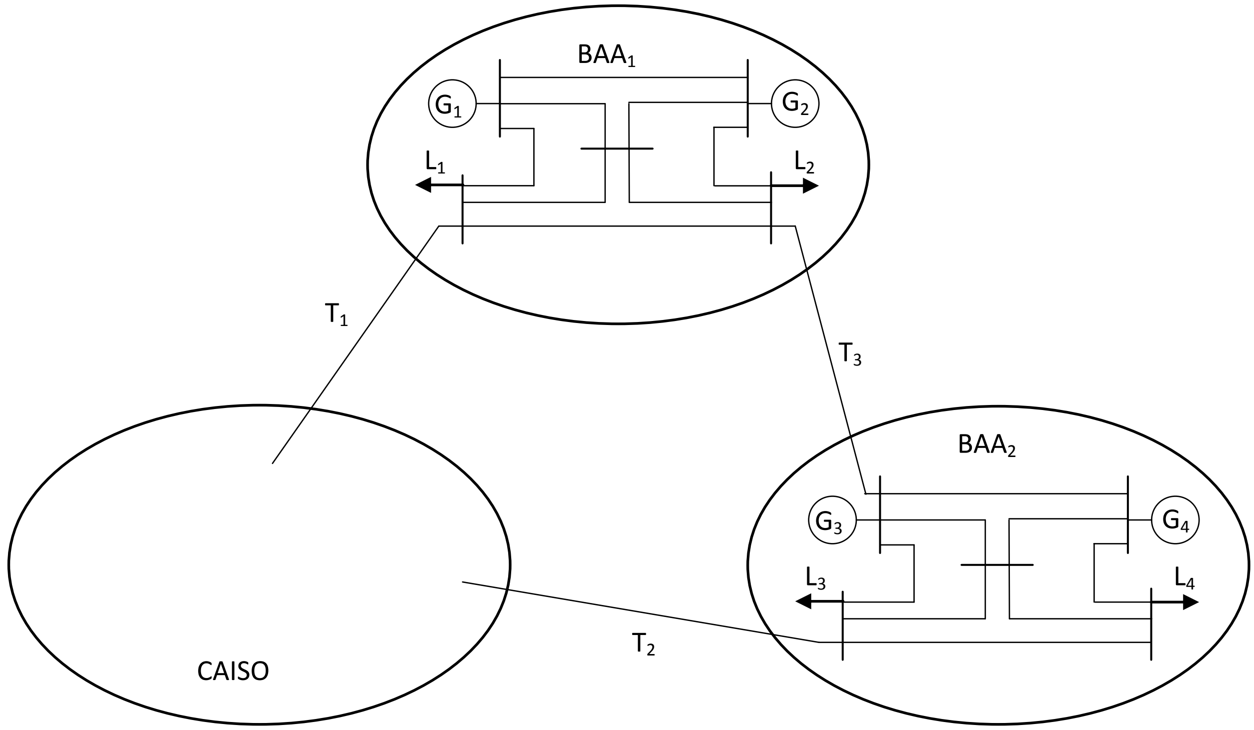


Table 7 shows the calculation of the base generation and load for the two external BAAs. A demand forecast of 1,000 MW is assumed for both BAAs; furthermore, a base net interchange of 100 MW is assumed from BAA_1 to BAA_2. Column [B] lists the total generation and load for each BAA; the total generation is equal to the demand forecast, adjusted by the net base interchange; the demand forecast includes transmission losses. Column [C] shows the historical generation distribution factors (GDF) and the historical load distribution factors (LDF) for each BAA. Column [D] shows the distribution of the total generation and the demand forecast to the resources and loads in each BAA based on the relevant historical distribution factors. As mentioned earlier, historical GDFs and LDFs can be derived from the state estimator solutions or received directly from the external BAA. Finally, column [E] shows the AC power flow solution with a distributed load slack and net interchange control. The AC power flow adjusts the load in each BAA (consistent with the LDFs) to absorb the transmission losses and maintain the net base interchange. A 3% loss (30 MW) is assumed in each BAA. The AC power flow solution yields the base generation and load schedules in each BAA at the resource level.

Table 7
Base generation and load schedules

BAA	Total generation, demand forecast, and base net interchange (MW)	GDF and LDF (%)	Distributed generation and demand using GDF/LDF (MW)	AC power flow solution (MW)
[A]	[B]	[C]	[D]	[E]
BAA_1			= [B] x [C]	
G_1	1,100	60	660	660
G_2		40	440	440
L_1	1,000	50	500	485
L_2		50	500	485
Losses	n/a			30
NSI	100		100	100
BAA_2				
G_3	900	40	360	360
G_4		60	540	540
L_3	1,000	50	500	485
L_4		50	500	485
Losses	n/a			30
NSI	–100		–100	–100

10.1.2 Import and export schedules

Assume next that Scheduling Coordinator 1 (SC_1) bids a 100 MW import over T_1 at $20/MWh, SC_2 bids a 100 MW import over T_2 at $25/MWh, SC_3 bids a 100 MW import over T_1 at $30/MWh, and SC_4 bids a 100 MW export over T_2 at $50/MWh. The four bids are identified as follows in Table 8 below. Note Resource IDs are not used to identify import/export schedules. Instead, Transaction IDs will be generated to identify each bid so that the information does not need to be kept in the Master File.

Table 8
Import and export bids at current scheduling points at the interties

Bid	SC	Bid ($/MWh)	Bid (MW)	Type	Intertie
B_1	SC_1	20	100	Import to ISO	T_1
B_2	SC_2	25	100	Import to ISO	T_2
B_3	SC_3	30	100	Import to ISO	T_1
B_4	SC_4	50	100	Export from ISO	T_2

In the day-ahead optimization, the ISO will enforce both a scheduling and a physical flow constraint for each intertie. This is discussed in detail in the next subsection.

Assume the LMP at the scheduling point for T_1 is \$26/MWh. Assume the LMP at the scheduling point for T_2 is \$28/MWh.

Given the bids submitted in Table 8 above, only bids B_1, B_2,t and B_4 clear the day-ahead market. Therefore, bid B_1 is paid the day-ahead LMP at the scheduling point for T_1 and bid B_2 is paid and bid B_4 is charged the day-ahead LMP at the scheduling point for T_2 as shown in Table 9 below. SC_1 should tag its schedule on intertie T_1, and SC_2 and SC_4 should tag their schedules on intertie T_2.

Table 9
Settlement for cleared imports and exports

Bid	SC	Type	Intertie	Schedule (MW)	LMP ($/MWh)	Charge ($)
B_1	SC_1	Import	T_1	100	26	–2,600
B_2	SC_2	Import	T_2	100	26	–2,600
B_3	SC_3	Import	T_1	0	28	0
B_4	SC_4	Export	T_2	100	28	2,800

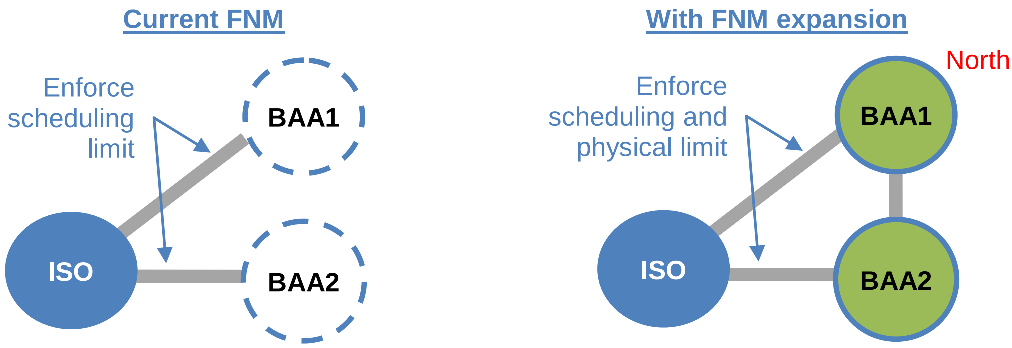
10.2 Example 2: enforcing scheduling and physical constraints on interties

Currently the ISO only enforces the scheduling constraint on interties with external BAAs as shown on the left hand side of Figure 4. With FNM expansion, the ISO will enforce both scheduling and physical constraints to improve the ISO's day-ahead and real-time intertie congestion management, as shown on the right hand side of Figure 4. The two constraints will be enforced at each ISO intertie to reflect:

a) The scheduling constraint that constrains the physical energy and ancillary services bids from scheduling hubs when these bids declare the respective intertie for schedule tagging; there are no shift factors used in these constraints. Both physical and virtual bids will be considered in this constraint in the integrated forward market. Only physical schedules will be considered in the residual unit commitment.
b) The physical flow constraint that constrains the schedule contributions from all physical and virtual energy bids inside and outside of the CAISO grid; shift factors are used in these constraints. Both physical and virtual bids will be considered in this constraint in the integrated forward market. Only physical schedules will be considered in the residual unit commitment.

Note that both the scheduling constraint and the physical constraint are limited by the same operational limit of the intertie.

Figure 4
Current and expanded FNM constraint enforcement



The following example uses the same full network model topology from the example in Section 10.1 to show the intertie constraint formulation.

For the bid quantities originally submitted and provided in Table 8 (all were assumed to be 100 MW), the scheduling limit constraints are as follows:

T_1: $OTC_{1,\text{min}} \leq B_1 + B_3 \leq OTC_{1,\text{max}}$

T_2: $OTC_{2,\text{min}} \leq B_2 - B_4 \leq OTC_{2,\text{max}}$

Where:

- $OTC_{1,min}$ is the minimum operational transfer capacity of T_1
- $OTC_{1,max}$ is the maximum operational transfer capacity of T_1
- $OTC_{2,min}$ is the minimum operational transfer capacity of T_2
- $OTC_{2,min}$ is the maximum operational transfer capacity of T_2

A positive number reflects an import into and a negative number reflects an export out of the ISO. These constraints would also include any ancillary services bids submitted at the scheduling hubs. Note that ancillary services do not provide counter flow.

The physical flow limit constraints are as follows:

T_1: $OTC_{1,\text{min}} \leq F_1 + 0.72\,B_1 + 0.72\,B_2 + 0.32\,B_3 - 0.32\,B_4 + \cdots \leq OTC_{1,\text{max}}$

T_2: $OTC_{2,\text{min}} \leq F_2 + 0.28\,B_1 + 0.28\,B_2 + 0.68\,B_3 - 0.68\,B_4 + \cdots \leq OTC_{2,\text{max}}$

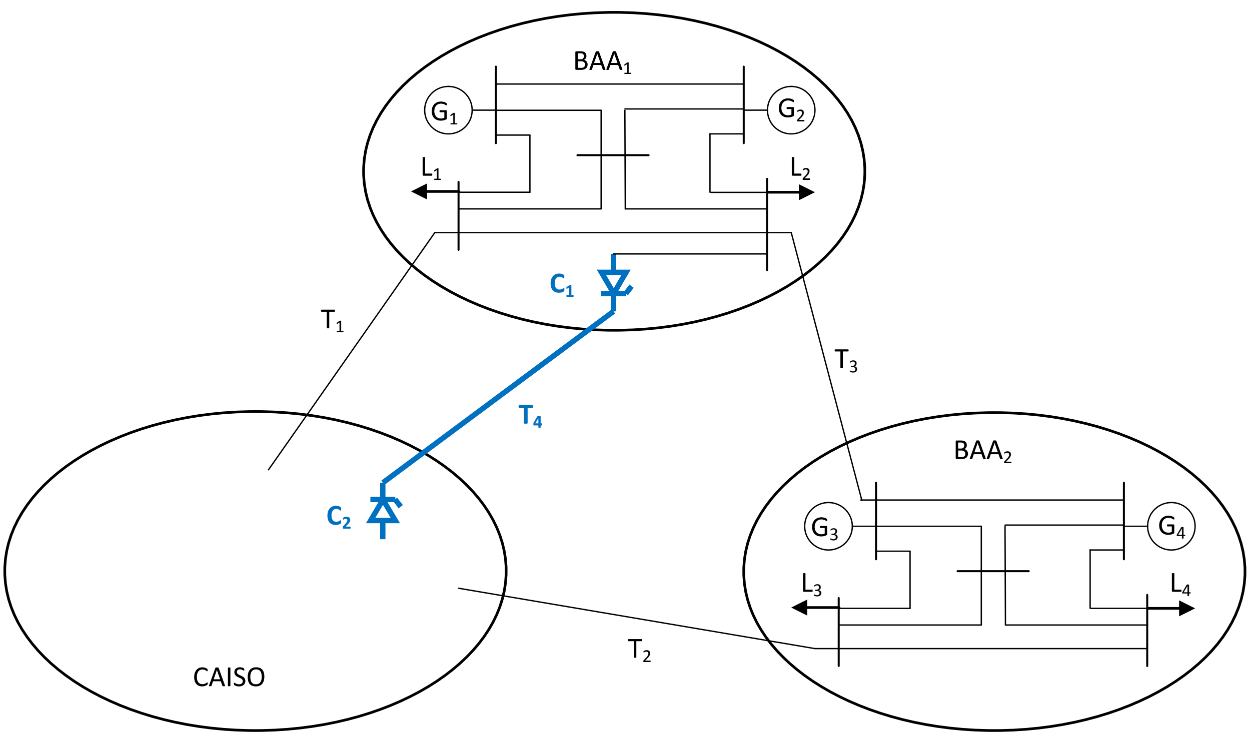
Where: F_1 and F_2 are the base power flows on T_1 and T_2, respectively. These constraints include the power flow contributions from all energy bids, physical and virtual alike, submitted at scheduling points, and internal resources (represented by the ellipsis in the equations above). The formula includes illustrative shift factors of 0.72, 0.32, 0.28. and 0.68.

As is clear from the formulation, both the scheduling constraint and the physical flow constraint are limited by the same operational limit of the specific intertie.

10.3 Example 3: high voltage direct current model

This example shows the proposed high voltage direct current (HVDC) model for scheduling imports and exports. A HVDC link (T_4 in blue) is added in the network example from Section 10.1, as shown in Figure 5 below. The converter stations C_1 and C_2 are in BAA_1 and the ISO, respectively. In other words, the HVDC link is an ISO intertie.

Figure 5
Proposed HVDC Scheduling



In this example, there are two additional 100 MW import bids, which declare the use of the HVDC link for schedule tagging as shown in Table 10 below.

Table 10
Bids on the HVDC link

Bid	SC	Type	Intertie
B_5	SC_5	Import	T_4
B_6	SC_6	Import	T_4

The power flow on the HVDC link is modeled by algebraic power injections at the converter station buses, as follows:

$$C_2 = B_5 + B_6$$

$$C_1 = -(1 + b)\ C_2$$

Where *b* is a power loss percentage estimate on the HVDC link and the converter transformers. Let us assume the following shift factors (SF) of the converter power injections on the AC interties as shown in Table 11 below.

Table 11
Shift Factors at HVDC converters

Resource	SF on T_1	SF on T_2
C_1	50%	50%
C_2	0%	0%

The intertie constraints including the new bids are now as follows:

Scheduling limits:

T_1: $OTC_{1,\text{min}} \leq B_1 + B_3 \leq OTC_{1,\text{max}}$

T_2: $OTC_{2,\text{min}} \leq B_2 - B_4 \leq OTC_{2,\text{max}}$

T_4: $OTC_{4,\text{min}} \leq B_5 + B_6 \leq OTC_{4,\text{max}}$

Physical limits:

$$OTC_{1,\text{min}} \leq F_1 + 0.72\ B_1 + 0.72\ B_2 + 0.72\ B_5 + 0.32\ B_3 - 0.32\ B_4 + 0.32\ B_6 - 0.5\ C_1\ + 0.0\ C_2 + \cdots \leq OTC_{1,\text{max}}$$

$$OTC_{2,\text{min}} \leq F_2 + 0.28\ B_1 + 0.28\ B_2 + 0.28\ B_5 + 0.68\ B_3 - 0.68\ B_4 + 0.68\ B_6 - 0.5\ C_1 + 0.0\ C_2 + \cdots \leq OTC_{2,\text{max}}$$

Assuming that both bids B_5 and B_6 clear the day-ahead market, the settlement is shown in Table 12 below.

Table 12
Settlement for cleared imports and exports including HVDC

Bid	SC	Type	Intertie	Schedule (MW)	LMP ($/MWh)	Charge ($)
B_1	SC_1	Import	T_1	100	26	–2,600
B_2	SC_2	Import	T_2	100	26	–2,600
B_3	SC_3	Import	T_1	0	28	0
B_4	SC_4	Export	T_2	100	28	2,800
B_5	SC_5	Import	T_4	100	26	–2,600
B_6	SC_6	Import	T_4	100	28	–2,800

Furthermore, assuming that the LMPs at the converter stations C_1 and C_2 are $27/MWh and $30/MWh, respectively, SC_5 and SC_6 receive the LMP difference ($3/MWh), *i.e.*, a supplemental charge of –$300 each, because their energy schedules for bids B_5 and B_6 flow on the HVDC link instead of the AC network. However, that supplemental charge is contingent on tagging the respective schedules on the HVDC intertie. SC_5 and SC_6 would also be responsible for their share on the HVDC losses, but this is not an ISO settlement.

Assuming a 1% power loss on the HVDC link (2MW), the rectifier (C_1) and inverter (C_2) power injections are fixed at –202 MW and 200 MW, respectively, in the AC power flow solution.

11 Pre-implementation analysis, benchmarking and data updates

The ISO believes the accuracy of its estimation of base schedules is the most important factor that will affect the accuracy of its loop flow modeling. The ISO plans to calibrate this estimation prior to implementing the FNM functionality and has already begun activities to support this. In addition, the ISO plans to conduct a pre-implementation analysis showing that the Phase 1 elements would be an improvement over today's modeling. This analysis would use the data and methodology proposed for creating base schedules in the day-ahead timeframe. At a minimum, the ISO envisions a conservative analysis comparing a day-ahead solution with and without the base schedules for selected BAAs to show the potential congestion caused by the unscheduled flow stemming from the base schedules. This congestion would serve as a proxy for real-time congestion imbalance offset costs from infeasible day-ahead schedules because those schedules did not account for unscheduled flow. The ISO would need to have the software code in order to complete this analysis. We are also working to provide a more robust pre-implementation analysis. This will likely involve additional requirements for our vendors and we will work with them on a plan of action. We will report the progress of any such plans to stakeholders by the February Board of Governors meeting. A more robust analysis would also require the software code. Therefore we expect to conduct the selected analysis (either the currently proposed analysis or the proposed more robust analysis if feasible) around the same time as the market simulation timeframe in Summer 2014.

The ISO proposes the following benchmarking metrics starting with Phase 1. These metrics and analyses will help the ISO improve modeling for the reliable, efficient operations of our markets and inform the stakeholder process for Phase 2.

1. **Market flows and actual flows** - As the ISO improves modeling in the expanded FNM, we expect market flows to come closer to actual (metered) flows. If they do not, we want to be able to understand the extent to which there is a mismatch, when, where, and how to improve. We propose to compare the following: (1) day-ahead market flows versus actual flows; and (2) real-time (both 15 minute and 5 minute) market flows versus actual flows.

2. **Compensating injections in real-time** – Though this initiative seeks to reduce the use of compensating injections by modeling the majority of unscheduled flows in the day-ahead, there will still be a need for compensating injections in the real-time. We propose to analyze the use of compensating injections in the real-time to better understand its effectiveness (volume used, location, timing) and the underlying reasons for its use. If the underlying reasons point to a modeling discrepancy, this can help us improve our modeling efforts and potentially account for this in the day-ahead timeframe.

3. **Real-time congestion imbalance offset cost tracking** – As mentioned in this proposal, there are several drivers of real-time congestion imbalance offset costs, one of which is the lack of unscheduled flow consideration in the day-ahead (causing congestion in the real-time). The ISO proposes to track real-time congestion imbalance offset costs by constraint that are caused by inaccurate day-head modeling of market flows, due to unscheduled flow from the interties. To the extent possible, the ISO will expand this analysis to other drivers of these costs but for the purpose of this initiative, the focus will be on improvements in day-ahead modeling.

For each of these analyses, granular data may not be available at go-live. However, we expect this to change so that we can provide more detailed analyses over time. The ISO is pro-actively analyzing the data needs and accessibility for FNM expansion go-live today. The ISO commits to release a technical bulletin or similar announcement providing the final list of modeled BAAs for Phase 1.

12 Next Steps

The ISO will discuss this third revised straw proposal with stakeholders on a conference call on January 7, 2014. Written comments are due by January 14, 2014 to FNM@caiso.com.

Appendix 1: Phase 2 proposal

The ISO is dividing the proposal into two phases. Phase 2 will continue in the stakeholder process and be brought to the ISO's Board of Governors at a later date. All of the subsections below are part of Phase 2.

13 Activity 1: scheduling point and hub definitions

Of the three major activities to support the objectives of the full network model expansion shown below in Table 13, the creation of scheduling points and hub definitions were part of Phase 2 rather than Phase 1.

Table 13
Objectives and Activities for Full Network Model Expansion

Objectives	Activities to support objectives
• Accurate loop flow modeling • Enhanced security analysis • Better analysis and outage coordination • Accurate high voltage direct current modeling	1. Model external balancing authority area generation, load, and transmission facilities (Phase 1), and scheduling point and hub definitions (Phase 2) 2. Enforce constraints for both scheduled and physical flow (Phase 1) 3. Include variables in high voltage direct current transmission modeling (Phase 1)

In Phase 2, the ISO proposes to define new scheduling hubs and points for pricing CAISO imports and exports as summarized in Table 14 below. The table shows the full transition from today's current model to Phase 1 and then Phase 2.

Table 14
Current and proposed modeling, scheduling and pricing

Current		**Full Network Model Expansion Proposals**	
Modeling, scheduling and pricing		**Modeling**	**Scheduling and pricing**
Scheduling points at the ISO interties; systems outside of ISO only partially modeled	Phase 1	• External generation , and load not involving ISO market transactions, as well as external transmission facilities will be modeled at external balancing authority areas • ISO imports/exports will be modeled at existing intertie scheduling points	• Remains at the current scheduling points at the interties unless an interchange scheduling agreement is signed
	Phase 2	• ISO imports/exports will be modeled in the same manner as they are scheduled and priced (scheduling hub, IBAA, etc.)	• Scheduling hubs: ○ North ○ South • IBAA export hub, and MEEA hubs • EIM Entity BAAs • CFE • Custom scheduling hubs at external BAA level or more granular depending on interchange scheduling agreements with the ISO

The straw proposal used the BAA footprint as the basis for modeling, scheduling, and pricing. Based on the revised straw proposal, we will keep the modeling of the expanded FNM at the BAA footprint but propose several different footprints for scheduling and pricing in Phase 2. As explained in more detail in Section 13.1, the different scheduling and pricing footprints will allow the ISO to ensure better convergence between import and export schedules and real-time flows. As we briefly explain here, the ISO's current proposal under Phase 2 will create five major categories of scheduling and pricing footprints. The first category is a scheduling hub which is an aggregation of balancing authorities in WECC. We have defined one for North and South and they are explained in detail in Section 13.2. Other scheduling points that will be used in the ISO's model for the WECC area include the existing export hub used by the integrated balancing authority areas (IBAAs) embedded in the ISO's footprint (and hubs created for modeling of Market Efficiency Enhancement Agreements within the IBAA), the energy imbalance market (EIM) entity, and the scheduling hub for the Comision Federal de Electricidad (CFE). The ISO may also define custom scheduling hubs at the external BAA level or at a more granular level depending on interchange scheduling agreements between interested and affected parties (such as scheduling coordinators or the appropriate resource owners) and the ISO. We explain our rationale for each of these in the following sections. The current scheduling points at the ISO interties would no longer be used for scheduling imports or exports.[33]

The scheduling hubs create a framework for the modeling to support Activity 1. In the next sections, we will discuss how the modeling is achieved in two "layers" under the Phase 2 approach. The first layer is the creation of a "base schedule," which reflects energy flows in the WECC resulting from energy schedules not involving the ISO. These schedules are important to model because they create physical flow impacts on the ISO system. This will be completed in Phase 1. The second layer is to superimpose on the base schedules imports from BAAs to (exports to BAAs from) the ISO. These will be modeled as incremental (or decremental) changes to the base schedule. The expanded model will also allow scheduling coordinators to submit physical or virtual import or export bids at each of the new scheduling hubs under Phase 2, as discussed below

13.1 Modeling imports and exports and Transaction IDs

The current model simplification (which will persist under Phase 1) assumes generation and load are located at exactly the ISO boundary, when this is clearly not realistic.[34] To reflect this, injections and withdrawals are modeled at the ISO interties when in fact actual generation and load are located elsewhere in WECC. The result of this modeling simplification is a decrease in the accuracy of the physical flow impact of these schedules. In other words, the ISO may assume more energy is flowing over specific interties where in reality the physical flow is more dispersed and therefore causes more unscheduled loop flow for the ISO and other BAAs in WECC. Under Phase 2, the ISO proposes to eliminate this simplifying assumption by modeling bids for imports to and exports from the ISO as originating from generators or sinks in the WECC. The distribution of the import/export schedules to the relevant supply resources is required to obtain a network solution (power flow solution) for the entire FNM to accurately represent loop flows in enforcing transmission constraints in the ISO and the ISO interties. Therefore, Phase 2 of the FNM expansion attempts to "move" the generation closer to the actual source, which will make pricing more accurate, even with aggregated scheduling hubs as discussed below.

13.1.1 Modeling imports and exports at the BAA level

Using the base schedules as the foundation, imports (exports) will be reflected as incremental (decremental) to those BAA base schedules. In other words, an import from a BAA into the ISO assumes that generation within the BAA is incrementing to support the import schedule. Conversely, an export from the ISO to the BAA assumes that generation in the BAA is

[33] However, the current scheduling points may be used to transition existing CRRs to the expanded FNM under Phase 2. See Section 13.3 for CRR discussion.
[34] See Section 6.4 for a discussion on the Victorville intertie.

decrementing from its base schedule to buy the energy from the ISO. As described above under Phase 1, the ISO will create generation and load aggregation points using default generation and load distribution factors, respectively, for each modeled BAA. The import and export schedules that clear the ISO's day-ahead or real-time market will be modeled by distributing the MW quantity to the relevant generation and load aggregation points of the relevant BAA. Refer back to Figure 2. Imports from BAA_1 are allocated to G_1 and G_2 using generation distribution factors the ISO developed for BAA_1 and imports from BAA_2 are allocated to G_3 and G_4 using generation distribution factors the ISO developed for BAA_2. As noted in Section 6.4 above, the ISO will not allow scheduling of static intertie bids at FNM boundary points so schedules will not be distributed back to these points, noted as resources G_5 and G_6 in Figure 2. In previous proposals, the ISO had allowed static intertie physical and virtual bidding at these boundary points. On further consideration, we are simplifying our approach to limit static intertie physical and virtual bidding to the scheduling hubs only. Intertie bids from dynamic resources can be placed at either scheduling hub or boundary points because these resources are under a dynamic scheduling agreement so the ISO will know where the energy is produced. Despite this simplification, including the boundary points for calculation of unscheduled loop flow will provide benefits and we can still provide to market participants pricing data at these points for informational purposes only.

13.1.2 Modeling imports and exports at the scheduling hub level

Due to various concerns noted in Section 13.2, the ISO proposes to aggregate BAAs into larger North and South scheduling hubs for scheduling and pricing purposes. The methodology for distributing the schedules onto the base schedules is exactly the same except that the footprint will change from the BAA to the aggregated scheduling hub. Distribution factors for the scheduling hubs are simply the aggregation of its contributing modeled BAAs. These schedules will be settled at the corresponding scheduling hub as discussed in Section 13.2.1. As noted in Table 15, there will be no change in modeling of intertie bids from dynamic resources but bids from static resources will be modeled at the scheduling hubs rather than the current scheduling points at the interties.

Table 15
General approach to modeling intertie bids

- Intertie bids from dynamic resources are modeled at detailed registered resources with unique resource IDs
- Static intertie bids are modeled at the scheduling hub with respect to the selected intertie without resource IDs

13.1.3 Transaction IDs

Transactions IDs will still be used with Phase 2 implementation with the only noticeable change limited to the “Location ID” field as noted in Table 5. In this field, market participants should note the appropriate scheduling hub rather than the current scheduling points at the interties. Note that under either phase, there may be other available locations such as the EIM entities or other configurations based on an executed interchange scheduling agreement.

Table 16
Transaction ID details

Category	Detail
Scheduling Coordinator ID	Same as today
Location ID	Scheduling Point (under Phase 1); Scheduling Hub (under Phase 2)
Primary Intertie ID	Used for schedule tagging and scheduling limit constraints
Alternate Intertie ID	Used for schedule tagging and scheduling limit constraints when the primary intertie is open and the Scheduling Coordinator has alternate scheduling agreement (dynamic transfer)
Bid Type	Physical or virtual, supply (import) or demand (export), firm/non-firm, wheeling, etc.
Counterpart transaction ID	For wheel through transactions only
Numeric ID	Integer-based ID provided by Scheduling Coordinator to help identify bid

13.2 Scheduling hub definitions under Phase 2 implementation

The ISO originally proposed to align the modeling of the FNM (at the BAA level) with scheduling and pricing (also at the BAA level). This would have allowed the ISO to calculate a shadow price for flow constraints from every BAA to every intertie. However, based on experience and lessons learned from the eastern ISOs[35], the CAISO proposes to limit the number of scheduling and pricing points used to calculate the shadow price of the flow constraints by aggregating most BAAs into two large scheduling hubs. The reason for this is because the source of an

[35] See testimony from of Dr. Scott Harvey in Exhibit ISO-3 and referenced report in Exhibit ISO-4 in FERC Docket No. ER08-1113, June 17, 2008. Available at: http://www.caiso.com/Documents/June17_2008ProposedRevisions-tariffsre-IntegratedBalancingAuthorityAreainDocketNo_ER08-1113-000.pdf

import listed on e-tags may not reflect the actual incremental generation that is moved to provide the import. For example, a scheduling coordinator tags generator A as the source of an ISO import. In reality, the scheduling coordinator may have previously planned for generator A to serve load outside the ISO. Simultaneously, the scheduling coordinator schedules and tags generator B as serving that load outside the ISO. The result is that generator B is the generator dispatched up pursuant to the ISO import schedule while generator A is tagged as the source of the ISO import. By consolidating the scheduling and pricing points to two major hubs, there is a limit to how the scheduling coordinator in this example can reconfigure its portfolio to achieve more favorable pricing.

The other ISOs' experiences highlight the difficulty in associating a schedule's source as indicated on the relevant e-tag(s) with the actual generation that was incremented to support the schedule, which may occur at another location. This disconnect would lead to a divergence between the schedules calculated by the model and actual flows. This situation would be exacerbated if there is a significant price differential between the two scheduling points. Again, consolidating the scheduling and pricing points will not eliminate but can decrease the error in modeled and actual flows.

The ISO considered an alternative proposal to aggregate all external BAAs into a single scheduling hub. The ISO rejected this proposal as an overly conservative starting point. Instead, we believe aggregating the majority of WECC into two major scheduling hubs provides some flexibility while allowing the ISO to model schedules that will reflect actual flows with a good measure of accuracy. While we expect the majority of e-tags to reflect the incremental generator, the ISO will monitor the convergence between modeled flows and real-time flows.

The ISO expects data provided on e-tags to be accurate and in accordance with the North American Energy Standards Board standards. During the Phase 2 stakeholder process, the ISO will develop with stakeholders settlement or tagging rules, as appropriate, to reinforce the expectation that e-tags should support schedules.

13.2.1 Scheduling hub and footprint definitions

Currently the ISO only defines scheduling points at the interties, which are used by scheduling coordinators for submitting bids and for pricing the cleared bids. Phase 2 of the FNM expansion will model external areas on a BAA footprint while scheduling and pricing may occur at a hub that could be different than the BAA footprint. Table 17 below shows the three different types of scheduling and pricing footprints introduced in this proposal.

Table 17
Scheduling hubs and custom options

	Scheduling hub (single BAA)	Scheduling hub (multiple BAAs)	Custom scheduling point or hub
Definition	Single BAA that can be accurately modeled as radial	Aggregation of several BAAs	Custom point or hub based on detailed data exchanged with ISO
Example	Comision Federal de Electricidad	North and South	Can be single generator, part of BAA, or entire BAA
Physical and virtual bid submission in the integrated forward market	Submit at scheduling hub specifying intertie	Submit at scheduling hub specifying intertie	Submit at custom point or hub specifying intertie
Physical and virtual bid settlement in the integrated forward market	LMP calculated from scheduling hub to an intertie to reflect tie-specific congestion	LMP calculated from scheduling hub to an intertie to reflect tie-specific congestion	LMP calculated from custom point or hub to an intertie to reflect tie-specific congestion
Residual unit commitment and real-time	Physical bids only	Physical bids only	Physical bids only

The most basic scheduling hub contains only one BAA, which is also radially connected to the ISO and not impacted by external loop flow. Thus, such a scheduling hub will have its modeling, scheduling, and pricing footprints aligned at the BAA level. Comision Federal de Electricidad will be modeled in this manner. For most BAAs, the modeling will be at the BAA level but the scheduling and pricing will be aggregated to a scheduling hub. The scheduling hubs are aggregations of BAAs and are discussed detail below. There is also the potential for creating custom scheduling points or hubs. If the ISO receives more granular information from interested and affected parties, a custom scheduling point or hub can be created with pricing that reflects actual resources, through an interchange scheduling agreement. This is discussed in more detail in Section 13.2.3.

In addition to the categories shown in Table 17, the EIM agreement will provide the ISO with detailed modeling information so that we will know where generation within each EIM entity is incrementing or decrementing to provide the schedules that clear the market. With this granular information, we can allow nodal scheduling and pricing within each EIM entity in the real-time market.[36] We discuss integrated balancing authority areas in Section 13.2.4.

[36] This is a simplified discussion of the EIM. Please see the separate EIM initiative for more details. http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx

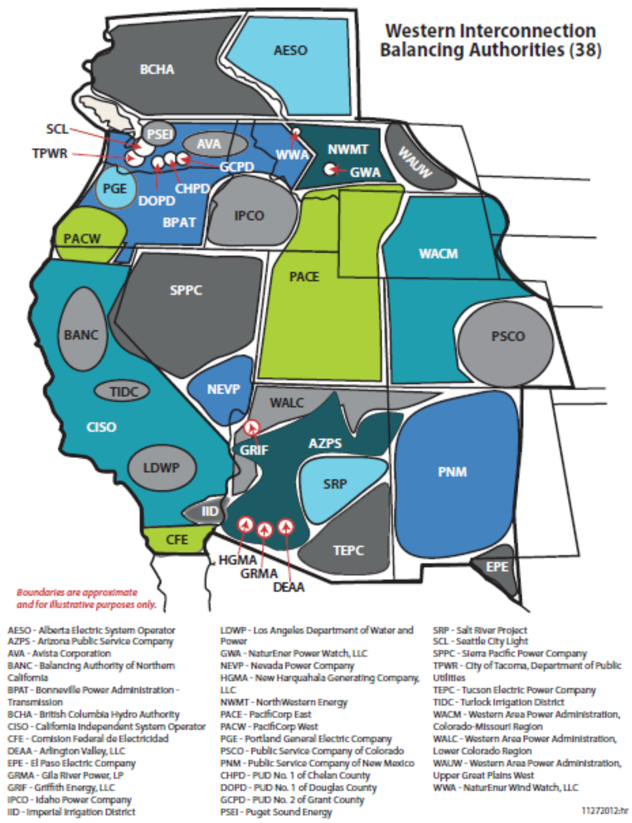
13.2.2 North and South scheduling hub definitions

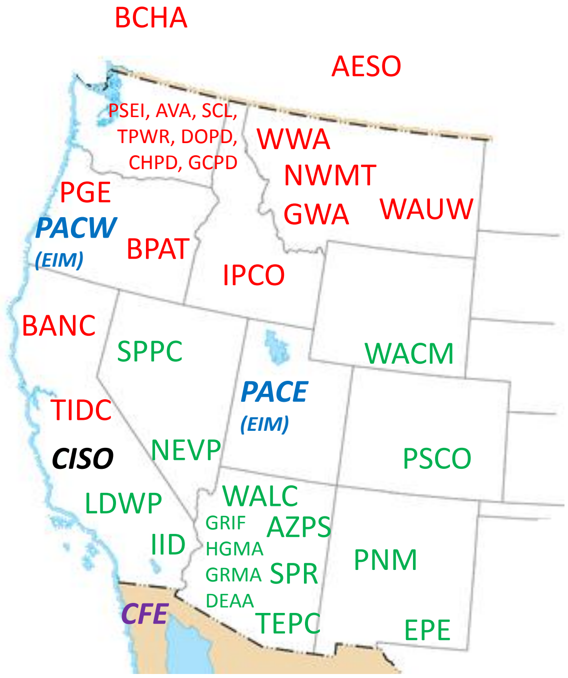
We propose to leverage WECC's unscheduled flow Transfer Distribution Factor (TDF) Matrix to define North and South scheduling hubs.[37] WECC produces the TDF Matrix every year for a winter and summer season analysis. The analysis assumes 100 MW is generated in a "sending" zone and the matrix shows how much of that original 100 MW will flow over a major WECC path to reach the "receiving" zone. The difference between the 100 MW generated and the total amount received is assumed to be the unscheduled flow based on the TDFs throughout WECC. For the ISO, the major path of interest is Path 66 (COI). The use of COI is appropriate because it is a major WECC path that when constrained will produce a price differential between the north and south. Therefore, the matrix provides for every zone in the WECC an approximate measure of the MWs out of 100 MW that will flow over COI to reach the ISO. If most of the 100 MW flows over COI, then the sending zone has a greater impact on the ISO's northern footprint. Note that the matrix uses zones, which are wholly contained within and aggregate up to BAAs. See Appendix 2: WECC unscheduled flow transfer distribution factor matrix for the mapping of zones to balancing authorities in a comparison of the matrix over seasons and years.

Figure 6 shows on the left all 38 WECC balancing authorities and their approximate location. The map on the right shows in red colored font those balancing authorities that the ISO designates as part of the North region and in green colored font those that are part of the South region. CFE (in purple), the EIM entity (in blue) and ISO (in black) are also shown.

[37] See WECC documents page at: http://www.wecc.biz/committees/StandingCommittees/OC/UFAS/Shared%20Documents/Forms/AllItems.aspx. The relevant documents are the "Summer 2013 TDF Matrix" MS Excel file and the "TDF Matrix Instructions" MS Word document.

Figure 6
WECC BAAs and ISO Proposed Scheduling Hub Definitions





Color coding: North region (red); South region (green); EIM entity (blue); CFE (purple); CISO (black).

Source: WECC BAA graphic available from:
http://www.wecc.biz/library/WECC%20Documents/Publications/WECC_BA_Map.pdf

Based on the WECC matrix, the ISO proposes to use a “bright line” cutoff of 50 MW (*i.e.*, 50 percent of flow) to divide the WECC BAAs into the North (≥50 MW) and South (<50 MW) scheduling hubs.[38] BAAs are wholly contained within one of the regional definitions if not already accounted for as shown in Figure 6. Therefore, all schedules originating in/sinking to a BAA in the North will receive the North price and all schedules originating in/sinking to a BAA in the South will receive the South price. The prices at each of the pricing hubs will be determined as the weighted average price of all BAAs in that regional definition, which in turn are determined as the weighted average price of all resources in the respective generation aggregation point definition.

[38] With the single exception of Sierra Pacific Power Company (SPPC) because of the scheduled online date of the One Nevada (ONLine) transmission line by the end of 2013. This project will strongly interconnect the northern and southern portions of Nevada and the ISO believes the overall impact will categorize both BAAs in the South. See the link for more information about the project: https://www.nvenergy.com/company/projects/images/ONLineTransmissionLineFactSheet.pdf

13.2.3 Scheduling hub considerations

It is expected that the aggregated modeling for each scheduling hub cannot reflect each individual generator in that region's impact on the flow and some generation could receive more favorable prices if they were modeled individually. So that the ISO is able to more accurately model generation more granularly than the scheduling hubs, and to receive pricing that reflects actual resource locations, market participants are encouraged to sign an agreement with the ISO that will allow us to model their scheduling transactions at more granular generation aggregation points than the two scheduling hubs. There is precedent in the ISO market for such an agreement in the Market Efficiency Enhancement Agreement (MEEA). MEEAs are currently only offered to IBAAs but this framework can be extended to other WECC entities, potentially with some appropriate modifications. See ISO tariff Sections 27.5.3.2 through 27.5.3.7 for the current information required to develop a MEEA (noting that this is only offered for IBAAs at the moment). The ISO proposes to develop such an interchange scheduling agreement or dynamic transfer agreement with interested and affected parties. Another alternative is available for EIM entities, which provide detailed generation data and receive nodal real-time pricing in return.

Table 18 lists some pros and cons of the ISO's proposed scheduling hub approach and finds that its transparency and simplicity is an appropriate first step in the FNM expansion effort.

Table 18
Pros and cons of ISO scheduling hub approach

	Pros	**Cons**
WECC analysis	• WECC analysis is publicly available • WECC analysis is updated annually with small changes year-to-year (barring major upgrades) • WECC zonal definitions can be aggregated to BAAs • Preserving BAA definition maps well with proposed ISO modeling	• ISO could develop more detailed analyses
Selection of COI	• COI represents a major path of concern for ISO	• Not every constraint in ISO is related to COI
Bright line 50 MW cutoff	• Transparent and easy to understand	• May not accurately capture flows for BAAs at the boundary
Pricing impact	• Providing two regional scheduling hubs is better than one, especially for real-time reliability • E-tags are not sufficient to verify granular generator locations so approach balances flexibility and reliability • Market participants are encouraged to sign an agreement for better pricing	• More scheduling points (rather than hubs) could provide greater pricing granularity • Some market participants could receive an unfavorable price at the regional scheduling hub than at an individual BAA

13.2.4 IBAA specific modifications under Phase 2 implementation

Integrated balancing authority areas (IBAAs) are not part of the modeling exercise proposed under the FNM expansion. Unless a MEEA is signed, the IBAAs will remain as they are currently modeled.

Imports from IBAAs are currently priced at the Captain Jack substation in Oregon and exports are priced at the SMUD hub. The Captain Jack substation was selected to reflect the expectation that imports from the IBAAs are actually originating from sources in the northwest, which would eventually flow on COI. In other words, if there is north-south congestion on COI, actual generation from the IBAAs may help relieve some of this congestion whereas additional flows from Captain Jack would exacerbate it. Our definition of North Hub includes those BAAs that are expected to have a majority of their schedules (50 percent or greater) flow over COI. This is consistent with the intent of using the Captain Jack substation as the import price for the IBAAs. We expect there to be limited pricing differences between the Captain Jack LMP and the North Hub. Therefore we propose to use the North Hub as the import pricing point for the IBAAs. This preserves the intent of the original import and export hub designation for IBAAs and limits any gaming potential should prices occasionally diverge. This change may require changes to the current ISO tariff.

We do not propose to change the current export hub for IBAAs at the SMUD hub.

13.3 Modeling of CRRs at new scheduling hubs

Figure 7 is an illustrative example of interties T_1 and T_3 between the ISO and scheduling hub A and interties T_2 and T_4 between the ISO and scheduling hub B. CRR obligations can be allocated and auctioned to source or sink at either A or B along any of the interties, subject to the source/sink limitations associated with the allocation rules.

Figure 7
Current CRRs with source/sink at Interties

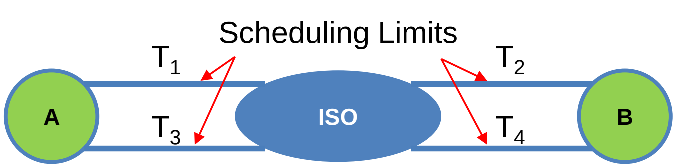
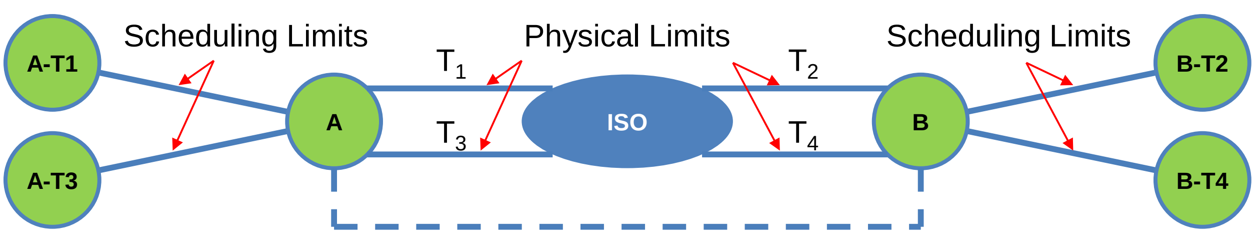


Figure 8 is an illustrative example of the new scheduling hubs under the FNM expansion. To facilitate bidding, scheduling, settlement, and CRRs, multiple scheduling points will be defined for each of these new scheduling hubs, one for each ISO intertie[39] associated with the respective scheduling hub for enforcing scheduling limits and submitting e-tags. (Refer also to the discussion in Section 13.6 below.) Physical and virtual bids in the day-ahead market and real-time market must be submitted at one of the scheduling hubs that is defined to a specific ISO intertie, which will be used to enforce the applicable scheduling limit and for submitting e-tags for the schedule that clears the relevant market. Virtual bids do not tag but the intertie information is still required by the ISO. Therefore, these physical and virtual schedules will be settled at the LMP of the relevant scheduling point, which may be different than the LMP of its associated scheduling hub due to a binding scheduling limit on the relevant ISO intertie. The scheduling points associated with the scheduling hub (*i.e.*, the hub and intertie pair) may be used as a CRR source or sink to provide the desired hedge for congestion cost in the day-ahead market. Scheduling limits will be enforced for CRR bids and nominations at a scheduling point on the associated intertie.

Figure 8, shows the scheduling points associated with two scheduling hubs: A and B. Scheduling point A-T1 is associated with intertie T_1 and scheduling point A-T3 is associated with intertie T_3. Similarly, scheduling point B-T2 is associated with intertie T_2 and scheduling point B-T4 is associated with intertie T_4.

Figure 8
CRRs at new scheduling hubs and associated points under FNM expansion



For previously released seasonal and long term CRRs still in effect at the time of the expanded FNM release, the ISO proposes to re-map existing CRRs at the interties to the new scheduling hubs, which will become the ultimate CRR source or sink. Table 19 below shows the mapping for each intertie and Cnode that allows CRRs to its corresponding CFE, North, or South Hub. This mapping process will be performed in the same manner that APNode name changes or retirements are handled in the current CRR process.

[39] And EIM interties in general in real-time market.

Table 19
Intertie to scheduling hub mapping

Hub	Intertie	Cnode
CFE	CFE	ROA-230_2_N101
CFE	CFE	TJI-230_2_N101
North	WESTLYLBNS	CAPTJACK_5_N003
North	TRACY500	CAPTJACK_5_N015
North	WESTLYTSLA	CAPTJACK_5_N504
North	TRACY500	CAPTJACK_5_N505
North	TRACY230	CAPTJACK_5_N506
North	RNCHLAKE	CAPTJACK_5_N507
North	RNCHLAKE	CAPTJACK_5_N508
North	LLNL	CAPTJACK_5_N509
North	CTW230	CAPTJACK_5_N510
North	RDM230	CAPTJACK_5_N511
North	COTPISO	CAPTJACK_5_N512
North	CASCADE	CRAGVIEW_1_GN001
North	PACI	MALIN_5_N101
North	NOB	SYLMARDC_2_N501
South	VEA	AMARGOSA_1_SN001
South	BLYTHE	BLYTHE_1_N101
South	IID-SCE	COACHELV_2_N101
South	IID-SDGE	ELCENTRO_2_N001
South	ELDORADO	FOURCORN_3_N501
South	ELDORADO	FOURCORN_5_N501
South	ADLANTO-SP	GONDER_2_N501
South	ADLANTO-SP	INTERM1G_7_N501
South	ADLANTO-SP	MARKETPL_5_N501
South	MCCULLGH	MCCULLGH_5_N101
South	ADLANTO-SP	MCCULLGX_5_N501
South	ADLANTO-SP	MEAD_5_N501
South	MEAD	MEADN_2_N501
South	MEAD	MEADS_2_N101
South	MERCHANT	MERCHANT_2_N101
South	ELDORADO	MOENKOPI_5_N101
South	ADLANTO-SP	MONA_3_N501
South	NGILABK4	NGILA1_5_N001
South	NWEST	NWEST_ASR-APND
South	PALOVRDE	PALOVRDE_ASR-APND
South	PARKER	PARKER_2_N101
South	SILVERPK	SLVRPS2_7_N001
South	SUMMIT	SUMMIT_ASR-APND
South	SYLMAR-AC	SYLMARLA_2_N501
South	VICTVL	VICTORVL_5_N101
South	ADLANTO-SP	WESTWING_5_N501

In previous papers an optional “bridging” mechanism had been proposed but upon further consideration, this would complicate matters if one scheduling coordinator opted to bridge a CRR and there did not exist a counterflow that was required in the original simultaneous feasibility test that did not elect the same bridging. To simplify the process, we will be applying the re-mapping option only.

13.4 Examples

This section provides three illustrative examples of the market clearing process that will use the expanded FNM. The first example will show how the ISO determines base schedules for each BAA prior to the day-ahead and real-time market run as will be implemented in Phase 1. It then explains how import and export schedules are superimposed on a base schedule (as an increment and decrement, respectively) and how they are settled as will be implemented in Phase 2. The second example explains how both scheduled and physical constraints are enforced and what the results are with and without congestion on the interties as will be implemented in Phase 1. The example provides the more complicated accounting under the Phase 2 approach. Finally, the third example is about the HVDC model that will be implemented in Phase 1. The example provides the more complicated accounting under the Phase 2 approach. See Appendix 3: detailed calculation of hub price for more detailed calculations of the locational marginal price at each hub that will be implemented in Phase 2.

13.4.1 Example 1: imports (exports) as incremental (decremental) to the base schedules

This example first describes how the base schedules are established. This process involves distributing the demand forecast for each balancing authority area to load nodes using the respective default load distribution factors. Similarly, the demand forecast net of any scheduled interchanges (e.g., day-ahead schedules with the ISO or other balancing authority areas, prior to the real-time market) will be distributed to the resources in each balancing authority area based on historical generation patterns using generation distribution factors, or based on the state estimator solution in the real-time market. The base schedule determination will include information about resource and transmission outages and other relevant data to the extent they are available. In the real-time market, the base schedules for the ISO are the day-ahead schedules.

The ISO will then run an AC power flow with net interchange control for each BAA to maintain its net schedule interchange. A distributed load slack will be used to distribute transmission losses in each balancing authority area. The resultant adjusted base schedules will be used as a reference in the subsequent market run.[40]

The ISO will then run its market performing congestion management for the ISO network and ISO interties.[41] Import and export schedules from bids at scheduling hubs that clear the market will be modeled as incremental and decremental market adjustments, respectively, on the base

[40] The process for determining and calculating adjusted base schedules is slightly different for EIM Entity BAAs in the RTM and it is described in detail in the EIM straw proposal.
[41] Congestion management is also applicable to EIM Entity BAAs in the RTM.

schedules of the associated resources. The ISO market solution will ignore the impact of transmission losses in external balancing authority areas on the locational marginal prices.[42]

13.4.1.1 Establishing the base schedule

Figure 9 shows the CAISO and two modeled external balancing authority areas: BAA_1 and BAA_2. BAA_1 has a generation aggregation point composed of G_1 and G_2 and a load aggregation point composed of L_1 and L_2. BAA_2 has a generation aggregation point composed of G_3 and G_4 and a load aggregation point composed of L_3 and L_4.

Figure 9
Import/export scheduling in the day-ahead market

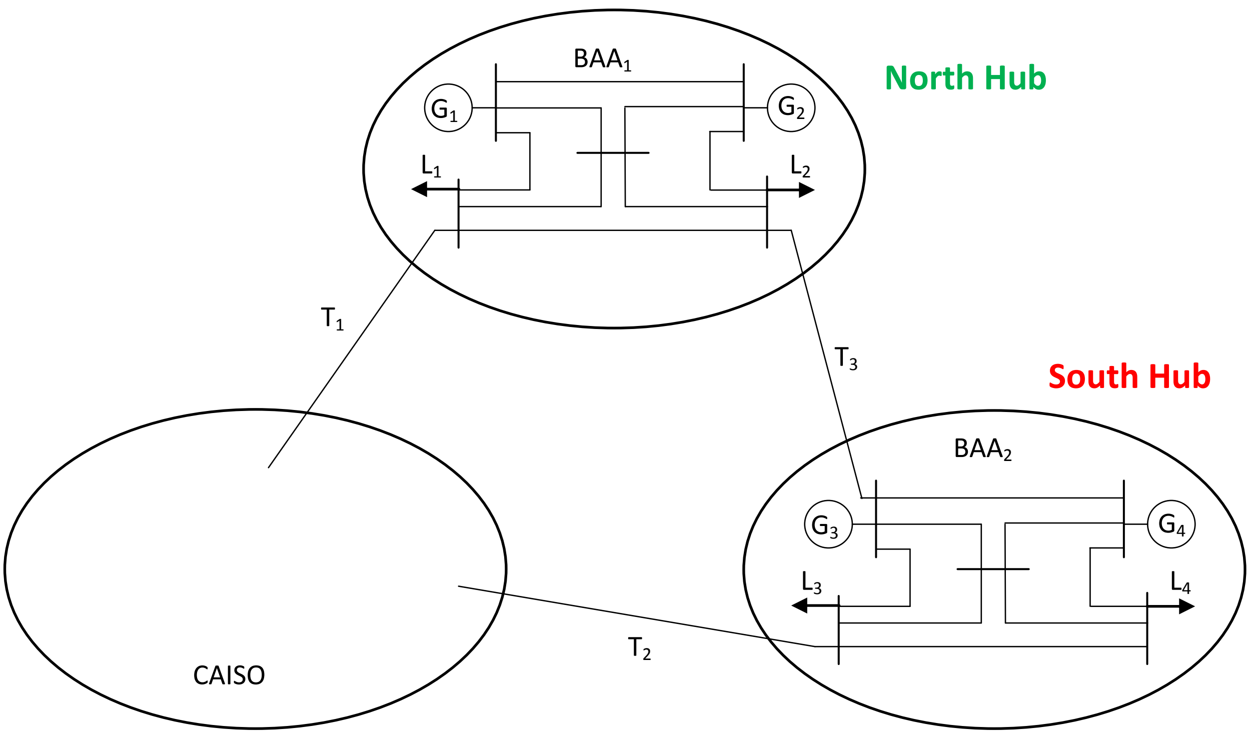


Table 7 shows the calculation of the base generation and load for the two external BAAs. A demand forecast of 1,000 MW is assumed for both BAAs; furthermore, a base net interchange of 100 MW is assumed from BAA_1 to BAA_2. Column [B] lists the total generation and load for each BAA; the total generation is equal to the demand forecast, adjusted by the net base

[42] With the exception of EIM Entity BAAs in the real-time market.

interchange; the demand forecast includes transmission losses. Column [C] shows the historical generation distribution factors (GDF) and the historical load distribution factors (LDF) for each BAA. Column [D] shows the distribution of the total generation and the demand forecast to the resources and loads in each BAA based on the relevant historical distribution factors. As mentioned earlier, historical GDFs and LDFs can be derived from the state estimator solutions or received directly from the external BAA. Finally, column [E] shows the AC power flow solution with a distributed load slack and net interchange control. The AC power flow adjusts the load in each BAA (consistent with the LDFs) to absorb the transmission losses and maintain the net base interchange. A 3% loss (30 MW) is assumed in each BAA. The AC power flow solution yields the base generation and load schedules in each BAA at the resource level. Once this base schedule is established, import/export schedules from/to each BAA are superimposed on base generation schedules in the relevant BAA.

Table 20
Base generation and load schedules

BAA	**Total generation, demand forecast, and base net interchange (MW)**	**GDF and LDF (%)**	**Distributed generation and demand using GDF/LDF (MW)**	**AC power flow solution (MW)**
[A]	**[B]**	**[C]**	**[D]**	**[E]**
BAA_1			= [B] x [C]	
G_1	1,100	60	660	660
G_2		40	440	440
L_1	1,000	50	500	485
L_2		50	500	485
Losses	n/a			30
NSI	100		100	100
BAA_2				
G_3	900	40	360	360
G_4		60	540	540
L_3	1,000	50	500	485
L_4		50	500	485
Losses	n/a			30
NSI	–100		–100	–100

13.4.2 Superimposing import and export schedules on the base generation schedules

Assume next that Scheduling Coordinator 1 (SC_1) bids a 100 MW import from BAA_1 at \$20/MWh, SC_2 bids a 100 MW import from BAA_1 at \$25/MWh, SC_3 bids a 100 MW import from BAA_2 at \$30/MWh, and SC_4 bids a 100 MW export to BAA_2 at \$50/MWh. Furthermore, SC1 and SC3 declare intertie T_1 and SC_2 and SC_4 declare intertie T_2 for schedule tagging. The four bids are identified as follows in Table 21 below. Note Resource IDs are not used to identify import/export schedules. Instead, Transaction IDs will be generated to identify each bid so that the information does not need to be kept in the Master File. Multiple SCs may submit bids at each scheduling hub.

Table 21
Import and export bids at scheduling hubs

Bid	SC	Bid ($/MWh)	Bid (MW)	Scheduling hub	Type	Intertie
B_1	SC_1	20	100	BAA_1	Import to ISO	T_1
B_2	SC_2	25	100	BAA_1	Import to ISO	T_2
B_3	SC_3	30	100	BAA_2	Import to ISO	T_1
B_4	SC_4	50	100	BAA_2	Export from ISO	T_2

In the day-ahead optimization, the ISO will enforce both a scheduling and a physical flow constraint for each intertie. This is discussed in detail in the next subsection.

If a bid clears the day-ahead market, the day-ahead schedule from that bid is distributed to the physical resources based on the default GDFs of the respective generation aggregation point as shown in Column [C] in Table 7 above. These GDFs are also used as weights in calculating the aggregate LMP for each scheduling hub from the LMPs of all generating resources in that hub.

Assume the LMP at BAA_1 is $26/MWh and reflects the North Hub. Assume the LMP at BAA_2 is $28/MWh and reflects the South Hub. For BAA_1, this aggregate LMP is derived from the LMPs at G_1 and G_2, weighted by the corresponding GDFs. Similarly for BAA_2, the aggregate LMP is derived from the LMPs at G_3 and G_4, weighted by the corresponding GDFs. We have simplified this example to show only one BAA in each North or South region. For multiple BAAs in each region, the LMP would reflect a weighted average price of all the generators in that region weighted by GDFs for distribution throughout the regional footprint, not just the individual BAAs.

Given the bids submitted in Table 8 above, only B_1 and B_2 at BAA_1, and B_4 at BAA_2 clear the day-ahead market. Since bids B_1 and B_2 are accepted, the day-ahead interchange of BAA_1 is a 200 MW import to ISO, in addition to the 100 MW base net interchange. Bid B_4 is also accepted as an export from ISO so the day-ahead interchange of BAA_2 is a 100 MW import from ISO, also in addition to the –100 MW base net interchange. It is important to note that the metering end of ISO interties is at the ISO side of the intertie; therefore transmission losses on the ISO interties are not part of the ISO net interchange.

These import and export schedules are then superimposed on the resource base schedules in the relevant BAAs. Table 22 below shows as a starting point the base schedule (from Column [E] in Table 8) in Column [B]. The net schedule interchange from the day-ahead market (DA NSI inclusive of ISO bids) is shown in Column [C] and its distribution to the resources in each BAA by the respective GDF is shown in Column [E]. Column [F] shows the result of superimposing the day-ahead schedules on the base generation in each BAA. Lastly, Column [G] shows the AC power flow solution with a distributed generation slack and net interchange control to maintain the net scheduled interchange for each BAA. This results in an increase in losses from 30 MW to 35 MW in BAA_1 and a decrease in losses from 30 MW to 25 MW in BAA_2. The change in the losses is absorbed by the resources in each BAA according to the relevant GDFs.

Table 22
Imports (exports) incremental (decremental) to base schedule

BAA	Base schedule (MW)	DA NSI inclusive of ISO bids (MW)	GDF and LDF (%)	DA NSI distribution based on GDF (MW)	Base and Day-Ahead Schedules (MW)	Loss adjustment in AC power flow (MW)
[A]	[B]	[C]	[D]	[E]	[F]	[G]
BAA_1				= [C] x [D]	= [B] + [E]	
G_1	660	200	60	120	780	783
G_2	440		40	80	520	522
L_1	485		50		485	485
L_2	485		50		485	485
Losses	30				30	35
NSI	100	300			300	300
BAA_2						
G_3	360	-100	40	–40	320	318
G_4	540		60	–60	480	477
L_3	485		50		485	485
L_4	485		50		485	485
Losses	30				30	25
NSI	–100	–200			–200	–200

The base schedules and the loss adjustment are not subject to settlement in the day-ahead market; only the cleared bids are subject to day-ahead settlement. Therefore, bids B_1 and B_2 are paid the day-ahead LMP at the BAA_1 North Hub and bid B_4 is charged the day-ahead LMP at the BAA_2 South Hub as shown in Table 9 below. SC_1 should tag its schedule on intertie T_1, and SC_2 and SC_4 should tag their schedules on intertie T_2.

Table 23
Settlement for cleared imports and exports

Bid	SC	Scheduling hub	Type	Intertie	Schedule (MW)	LMP ($/MWh)	Charge ($)
B_1	SC_1	BAA_1	Import	T_1	100	26	–2,600
B_2	SC_2	BAA_1	Import	T_2	100	26	–2,600
B_3	SC_3	BAA_2	Import	T_1	0	28	0
B_4	SC_4	BAA_2	Export	T_2	100	28	2,800

13.5 Example 2: enforcing scheduling and physical constraints on interties

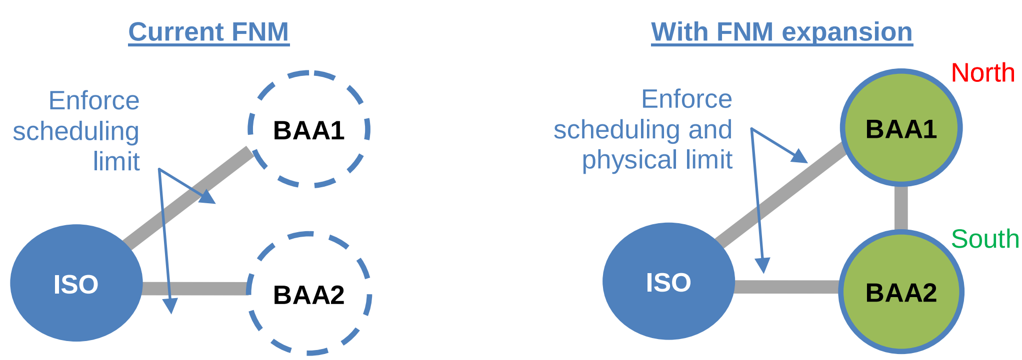
Currently the ISO only enforces the scheduling constraint on interties with external BAAs as shown on the left hand side of Figure 4. With FNM expansion, the ISO will enforce both scheduling and physical constraints to improve the ISO's day-ahead and real-time intertie congestion management, as shown on the right hand side of Figure 4. The two constraints will be enforced at each ISO intertie to reflect:

c) The scheduling constraint that constrains the physical energy and ancillary services bids from scheduling hubs when these bids declare the respective intertie for schedule tagging; there are no shift factors used in these constraints. Both physical and virtual bids will be considered in this constraint in the integrated forward market. Only physical schedules will be considered in the residual unit commitment.

d) The physical flow constraint that constrains the schedule contributions from all physical and virtual energy bids inside and outside of the CAISO grid; shift factors are used in these constraints. Both physical and virtual bids will be considered in this constraint in the integrated forward market. Only physical schedules will be considered in the residual unit commitment.

Note that both the scheduling constraint and the physical constraint are limited by the same operational limit of the intertie.

Figure 10
Current and expanded FNM constraint enforcement



The following example uses the same full network model topology from the example in Section 13.4 to show the intertie constraint formulation. The resources in Column [A] and GDFs in Column [B] shown in Table 24 below are the same as provided in Table 7 earlier. Assume that the shift factors (SF) from external resources to the ISO distributed load slack[43] are as shown in Table 24 Column [C] for intertie 1 (T_1) and Column [E] for intertie 2 (T_2). Column [D] shows the aggregate SF for T_1 and Column [F] the aggregate SF for T_2. The rows for "Aggregate BAA_1" and "Aggregate BAA_2" show the aggregate shift factor calculation for each BAA on the two ISO interties.

[43] The distributed load slack for the entire EIM footprint is used in RTM.

Table 24
Shift factors from external resources to the ISO distributed load slack

Resource	GDF (%)	SF on T_1 (%)	Aggregate SF on T_1 (%)	SF on T_2 (%)	Aggregate SF on T_2 (%)
[A]	[B]	[C]	[D]	[E]	[F]
			= [B] x [C]		= [B] x [E]
G_1	60	80	48	20	12
G_2	40	60	24	40	16
			= G_1 + G_2		= G_1 + G_2
Aggregate BAA_1			72		28
G_3	40	20	8	80	32%
G_4	60	40	24	60	24%
			= G_1 + G_2		= G_1 + G_2
Aggregate BAA_2			32		68

For the bid quantities originally submitted and provided in Table 8 (all were assumed to be 100 MW), the scheduling limit constraints are as follows:

T_1: $OTC_{1,\text{min}} \leq B_1 + B_3 \leq OTC_{1,\text{max}}$

T_2: $OTC_{2,\text{min}} \leq B_2 - B_4 \leq OTC_{2,\text{max}}$

Where:

- $OTC_{1,min}$ is the minimum operational transfer capacity of T_1
- $OTC_{1,max}$ is the maximum operational transfer capacity of T_1
- $OTC_{2,min}$ is the minimum operational transfer capacity of T_2
- $OTC_{2,min}$ is the maximum operational transfer capacity of T_2

A positive number reflects an import into and a negative number reflects an export out of the ISO. These constraints would also include any ancillary services bids submitted at the scheduling hubs. Note that ancillary services do not provide counter flow.

The physical flow limit constraints are as follows:

T_1: $OTC_{1,\text{min}} \leq F_1 + 0.72\ B_1 + 0.72\ B_2 + 0.32\ B_3 - 0.32\ B_4 + \cdots \leq OTC_{1,\text{max}}$

T_2: $OTC_{2,\text{min}} \leq F_2 + 0.28\ B_1 + 0.28\ B_2 + 0.68\ B_3 - 0.68\ B_4 + \cdots \leq OTC_{2,\text{max}}$

Where: F_1 and F_2 are the base power flows on T_1 and T_2, respectively. These constraints include the power flow contributions from all energy bids, physical and virtual alike, submitted at scheduling hubs, and internal resources (represented by the ellipsis in the equations above).

As is clear from the formulation, both the scheduling constraint and the physical flow constraint are limited by the same operational limit of the specific intertie.

13.6 Example 2a: congestion on the interties

Examples 1 and 2 above have been simplified to assume that there is no scheduling congestion on the interties. This is demonstrated from the LMPs in Table 9. For example, the LMPs for scheduling hub BAA_1 is $26/MWh for both interties T1 and T2. However, if the scheduling constraint were to bind, it would create a shadow price that would lead to a price differential between the intertie and the scheduling hub. In this example, the interties are considered to be radial to the scheduling hub so T1 may bind while T2 does not. Table 10 below shows how the intertie specific LMP from a scheduling hub may be different from the scheduling hub itself.

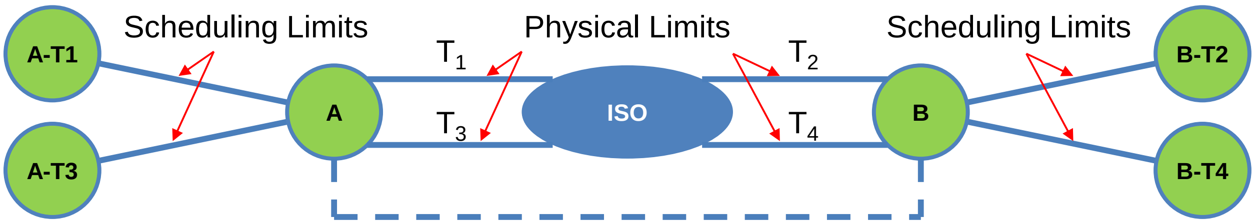
Table 25
LMPs with intertie congestion

LMP ($/MWh) at:	No congestion	Congestion on T1	Congestion on T2	Congestion on T1 and T2
Scheduling hub BAA_1	26	26	26	26
Scheduling hub BAA_1 to T1	26	21	26	21
Scheduling hub BAA_1 to T2	26	26	24	24

Table 26 should be understood in conjunction with the scheduling hub discussion summarized in Table 17. Note that a LMP differential only occurs when scheduling constraints bind. This is because a physical constraint will impact all of the system equally whereas the scheduling limits are specific to physical bids tagged to and virtual bids that specify that intertie. Therefore, Table 26 above notes that for physical bid settlement, the LMP will be calculated from the scheduling hub to an intertie to reflect tie-specific congestion.

Figure 8 from the CRR discussion is reproduced below (relabeled as Figure 11) to illustrate the example above with congestion (and to show how the CRR model and FNM are aligned). Assume A and B are scheduling hubs, each with an LMP. The physical and scheduling constraints on interties T_1, T_2, T_3, and T_4 are enforced. If there is congestion on each of the interties, then a separate LMP will be calculated for each scheduling hub to intertie pair, modeled as a radial connection. This is represented as scheduling points A-T1 and A-T3 for scheduling hub A to interties T1 and T3, respectively, and B-T2 and B-T4 for scheduling hub B to interties T2 and T4, respectively.

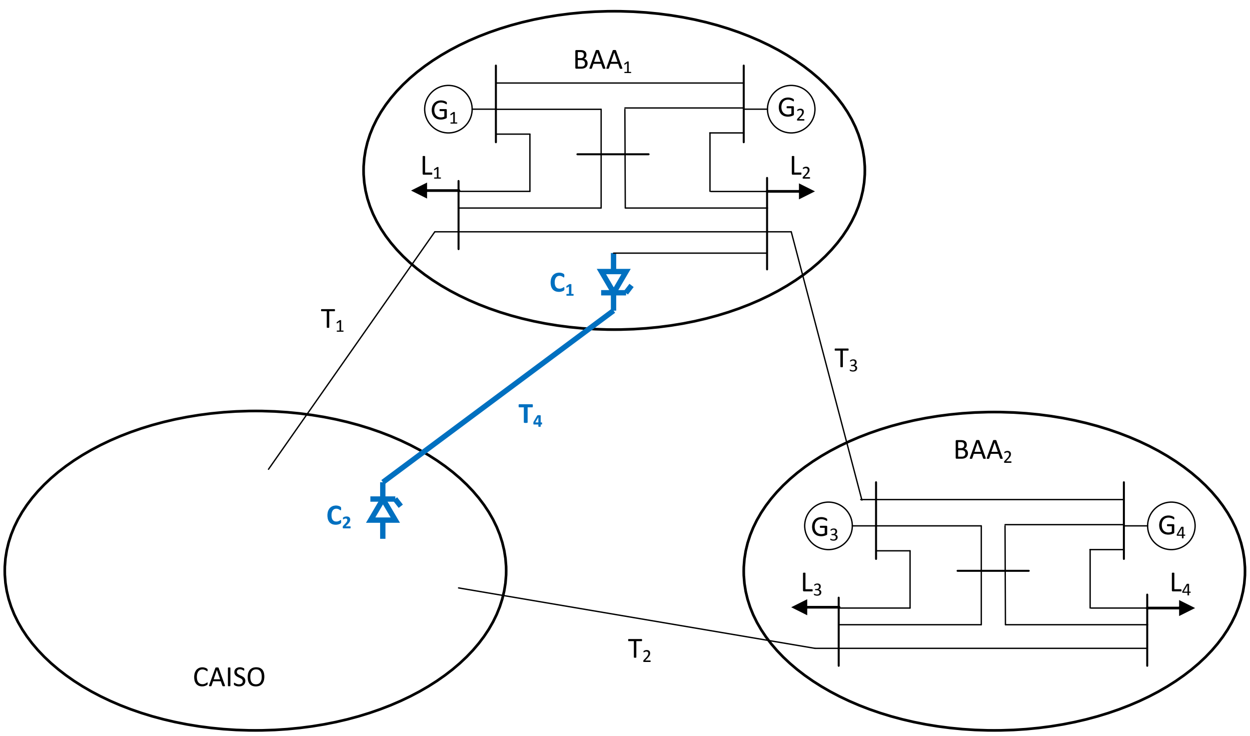
Figure 11
CRRs at new aggregate scheduling points under FNM expansion



13.7 Example 3: high voltage direct current model

This example shows the proposed high voltage direct current (HVDC) model for scheduling imports and exports. A HVDC link (T_4 in blue) is added in the network example from Section 13.4, as shown in Figure 5 below. The converter stations C_1 and C_2 are in BAA_1 and the ISO, respectively. In other words, the HVDC link is an ISO intertie.

Figure 12
Proposed HVDC Scheduling



In this example, there are two additional 100 MW import bids, which declare the use of the HVDC link for schedule tagging as shown in Table 10 below.

Table 26
Bids on the HVDC link

Bid	SC	Scheduling Point	Type	Intertie
B_5	SC_5	BAA_1	Import	T_4
B_6	SC_6	BAA_2	Import	T_4

The power flow on the HVDC link is modeled by algebraic power injections at the converter station buses, as follows:

$$C_2 = B_5 + B_6$$

$$C_1 = -(1 + b)\ C_2$$

Where *b* is a power loss percentage estimate on the HVDC link and the converter transformers. Let us assume the following shift factors (SF) of the converter power injections on the AC interties as shown in Table 11 below.

Table 27
Shift Factors at HVDC converters

Resource	SF on T_1	SF on T_2
C_1	50%	50%
C_2	0%	0%

The intertie constraints including the new bids are now as follows:

Scheduling limits:

T_1: $OTC_{1,\text{min}} \leq B_1 + B_3 \leq OTC_{1,\text{max}}$

T_2: $OTC_{2,\text{min}} \leq B_2 - B_4 \leq OTC_{2,\text{max}}$

T_4: $OTC_{4,\text{min}} \leq B_5 + B_6 \leq OTC_{4,\text{max}}$

Physical limits:

$$OTC_{1,\text{min}} \leq F_1 + 0.72\ B_1 + 0.72\ B_2 + 0.72\ B_5 + 0.32\ B_3 - 0.32\ B_4 + 0.32\ B_6 - 0.5\ C_1\ + 0.0\ C_2 + \cdots \leq OTC_{1,\text{max}}$$

$$OTC_{2,\text{min}} \leq F_2 + 0.28\ B_1 + 0.28\ B_2 + 0.28\ B_5 + 0.68\ B_3 - 0.68\ B_4 + 0.68\ B_6 - 0.5\ C_1 + 0.0\ C_2 + \cdots \leq OTC_{2,\text{max}}$$

Assuming that both bids B_5 and B_6 clear the day-ahead market, the settlement is shown in Table 12 below.

Table 28
Settlement for cleared imports and exports including HVDC

Bid	SC	Scheduling Point	Type	Intertie	Schedule (MW)	LMP ($/MWh)	Charge ($)
B_1	SC_1	BAA_1	Import	T_1	100	26	–2,600
B_2	SC_2	BAA_1	Import	T_2	100	26	–2,600
B_3	SC_3	BAA_2	Import	T_1	0	28	0
B_4	SC_4	BAA_2	Export	T_2	100	28	2,800
B_5	SC_5	BAA_1	Import	T_4	100	26	–2,600
B_6	SC_6	BAA_2	Import	T_4	100	28	–2,800

Furthermore, assuming that the LMPs at the converter stations C_1 and C_2 are $27/MWh and $30/MWh, respectively, SC_5 and SC_6 receive the LMP difference ($3/MWh), *i.e.*, a supplemental charge of –$300 each, because their energy schedules for bids B_5 and B_6 flow on the HVDC link instead of the AC network. However, that supplemental charge is contingent on tagging the respective schedules on the HVDC intertie. SC_5 and SC_6 would also be responsible for their share on the HVDC losses, but this is not an ISO settlement.

Assuming a 1% power loss on the HVDC link (2MW), the rectifier (C_1) and inverter (C_2) power injections are fixed at –202 MW and 200 MW, respectively, in the AC power flow solution, which is shown in Table 29 below.

Table 29
External BAA load, generation, and net interchange

BAA_1		BAA_2	
G_1	846 MW	G_3	360 MW
G_2	564 MW	G_4	540 MW
L_1	485 MW	L_3	485 MW
L_2	485 MW	L_4	485 MW
C_1	–202 MW		
C_2	200 MW		
AC Losses	38	Losses	30
NSI_1	400 MW	NSI_2	–100 MW

In the power flow solution, the additional 100 MW schedule from B_5 is distributed to G_1 and G_2 according to the relevant GDFs. Similarly, the additional 100 MW schedule from B_6 is distributed to G_3 and G_4 according to the relevant GDFs. Furthermore, the DC losses in BAA_1 (2MW) and the additional AC transmission losses in BAA_1 (assumed 3 MW) and in BAA_2 (assumed 5 MW) are also distributed to the relevant generating resources in these BAAs according to the relevant GDFs. Note that the power injection at the inverter station C_2 must be included in the net interchange control for BAA_1 to accurately reflect the power export over the HVDC intertie.

Appendix 2: WECC unscheduled flow transfer distribution factor matrix

WECC Unscheduled Flow Transfer Distribution Factor Matrix for Receiving in CAISO - comparison of seasonal and annual

			2013 Summer		2012 Summer		2011 Summer		Summer 2010		2009 Summer		2008 Summer		2007 Summer	
	BAA	**Unsch. Flow zone**	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS
	AESO	ALBERTA	87	75	87	75	86	75	87	77	88	77	88	77	88	77
	AVA	AVA	86	75	86	75	86	74	87	77	87	77	87	76	87	76
	AVA	COLSTRIP	81	69	81	70	81	69	82	72	82	72	82	72	82	72
	AVA	MIDC	87	76	87	76	87	75	88	77	88	78	88	78	88	78
	AZPS	AZEAST	21	9	21	9	21	10	20	9	19	9	20	9	20	9
	AZPS	AZSOUTH	20	8	20	8	20	8	19	8	18	8	19	8	19	8
A	AZPS	AZSOWEST	15	4	15	0	15	0	14	3	14	0	14	0	14	3
E	AZPS	FCNAREA	24	13	24	13	25	14	23	13	23	12	23	13	23	13
R	AZPS	FCNUNIT5	23	11	23	11	23	12	21	11	21	11	21	11	21	11
A	AZPS	PHOENIX	18	6	18	6	18	6	17	6	16	6	16	6	17	6
	AZPS	PVAREA	17	5	17	0	17	0	15	5	15	0	15	0	15	5
G	BANC	SMUD	-1	-13	0	-12	0	-12	-1	-11	0	-11	0	-11	-1	-11
N	BCTC	BC HYDRO	87	75	87	75	87	75	88	77	88	77	88	77	88	77
I	BPA	ASHE	88	76	87	76	87	76	88	78	88	78	88	78	88	78
D	BPA	BPA	87	76	87	76	87	76	88	78	88	78	88	78	88	77
N	CFE	CFE	14	3	14	0	14	0	13	2	13	0	13	0	13	2
E	CISO	ISON	0	-11	0	-11	0	-11	0	-10	0	-10	0	-10	0	-10
S	CISO	ISOS	11	0	11	0	11	0	10	0	10	0	10	0	10	0
	DOPD	DOPD	87	75	87	76	87	75	88	77	88	78	88	78	88	77
	EPE	EPE	22	10	22	11	22	11	21	10	20	10	21	10	21	10
	EPE	EPEDC	25	13	25	13	25	14	24	13	23	13	23	13	23	13
	IID	IID	14	3	14	0	14	0	13	2	13	0	12	0	13	2
	IPCO	BRIDGER	66	54	66	54	65	54	69	58	69	59	69	59	70	60
	IPCO	IPC	78	66	78	66	77	66	80	69	81	70	81	70	80	70

		2012-13 - Winter		2011-12 Winter		2010-2011 Winter		2009-10 Winter		2008-09 Winter	
BAA	**Unsch. Flow zone**	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS
AESO	ALBERTA	87	76	86	74	87	75	88	77	88	77
AVA	AVA	87	75	87	75	87	75	87	77	87	77
AVA	COLSTRIP	82	70	82	70	82	70	82	72	83	72
AVA	MIDC	88	76	88	76	88	76	88	78	88	78
AZPS	AZEAST	22	10	21	10	22	10	20	10	20	10
AZPS	AZSOUTH	20	9	20	9	21	9	19	8	19	8
AZPS	AZSOWEST	16	0	16	0	16	0	14	0	14	0
AZPS	FCNAREA	25	13	25	13	25	13	23	13	23	13
AZPS	FCNUNIT5	23	12	23	11	23	11	21	11	22	11
AZPS	PHOENIX	19	7	19	7	19	7	17	7	17	6
AZPS	PVAREA	18	6	17	6	18	6	16	6	16	0
BANC	SMUD	0	-12	0	-12	0	-12	0	-11	0	-11
BCTC	BC HYDRO	87	76	87	76	87	75	88	77	88	77
BPA	ASHE	88	76	88	76	88	76	88	78	89	78
BPA	BPA	88	76	88	76	88	76	88	78	89	78
CFE	CFE	15	0	15	0	15	0	13	0	14	0
CISO	ISON	0	-11	0	-11	0	-11	0	-10	0	-10
CISO	ISOS	11	0	11	0	11	0	10	0	10	0
DOPD	DOPD	88	76	88	76	87	76	88	77	88	78
EPE	EPE	23	11	22	11	23	11	21	11	21	11
EPE	EPEDC	25	14	25	13	25	13	24	13	24	13
IID	IID	14	0	14	0	15	0	13	0	13	0
IPCO	BRIDGER	67	55	66	55	66	54	69	58	70	59
IPCO	IPC	79	68	79	67	79	67	81	70	81	71

WECC Unscheduled Flow Transfer Distribution Factor Matrix for Receiving in CAISO - comparison of seasonal and annual

			2013 Summer		2012 Summer		2011 Summer		Summer 2010		2009 Summer		2008 Summer		2007 Summer		2012-13 - Winter		2011-12 Winter		2010-2011 Winter		2009-10 Winter		2008-09 Winter	
	BAA	Unsch. Flow zone	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS	ISON	ISOS
	LDWP	INTERMOU	56	44	56	44	55	43	53	42	53	42	53	42	53	42	57	45	56	45	56	44	52	41	53	43
	LDWP	LDWP	12	0	11	0	12	0	10	0	10	0	10	0	10	0	12	0	12	0	12	0	10	0	11	0
	NEVP	NEVP	16	5	16	0	16	0	14	4	14	0	14	0	14	4	17	0	17	0	17	0	15	0	15	0
	NWMT	NWMT	81	70	81	70	81	70	82	72	83	72	83	72	83	72	82	70	82	71	82	70	82	72	83	72
	PACE	BOZ/NEUT	54	42	54	42	53	42	52	42	53	42	53	42	53	42	54	43	54	42	54	43	52	42	53	43
A	PACE	FCNUNIT4	25	13	25	13	25	14	23	13	23	12	23	13	23	13	25	14	25	13	25	13	23	13	24	13
E	PACE	GLENCANY	21	9	21	10	21	10	20	10	20	10	20	10	21	10	22	11	22	10	23	11	21	10	21	11
R	PACE	PACE/ID	68	56	68	56	66	55	70	59	70	59	71	60	71	60	68	57	67	56	68	56	69	59	71	60
A	PACE	PACE/UT	55	44	55	43	54	43	51	41	52	41	51	41	52	41	56	44	55	44	55	43	51	40	51	41
	PACE	PACE/WYO	63	51	63	51	62	50	62	51	62	51	62	52	62	52	63	52	63	51	63	51	61	51	63	52
G	PACW	PACW/SOR	89	77	89	78	89	77	90	80	90	80	90	80	90	80	90	78	90	78	90	78	90	80	91	80
N	PACW	PACW/SWW	88	76	88	76	88	76	88	78	88	78	88	78	88	78	88	77	88	77	88	76	89	78	89	78
I	PGE	PGE	88	77	88	77	88	76	89	78	89	79	89	79	89	78	89	77	89	77	89	77	89	78	89	79
D	PNM	PNM	25	13	25	14	25	14	24	13	23	13	23	13	23	13	26	14	25	14	25	13	24	13	24	13
N	PSCO	COLO/NE	49	38	50	38	49	38	49	38	48	38	48	38	49	38	50	38	50	38	50	38	48	38	49	38
E	PSCO	COLO/SE	48	37	48	37	48	37	47	37	46	36	47	36	47	37	49	37	49	37	49	37	46	36	47	36
S	PSCO	CRG/HAY	48	36	48	37	48	36	47	37	47	36	47	37	47	37	49	37	48	37	49	37	46	36	47	37
	PSE	PSE	87	75	87	76	87	75	88	77	88	78	88	78	88	77	88	76	88	76	87	76	88	77	88	78
	SCL	SCL	87	75	87	75	86	75	87	77	87	77	87	77	87	77	87	76	87	75	87	75	88	77	88	77
	SCL	WKPL	87	75	87	75	86	75	87	77	87	77	87	77	87	77	87	76	87	75	87	75	87	77	88	77
	SPPC	SPP	72	61	72	61	73	61	73	62	73	63	73	63	73	62	72	60	74	62	73	61	72	62	73	63
	SRP	NAVAJO	17	5	17	0	17	0	15	5	15	0	15	0	15	5	17	6	17	0	17	0	15	0	15	0
	TPWR	TPWR	88	76	87	76	87	76	88	78	88	78	88	78	88	78	88	76	88	76	88	76	88	78	89	78
	WACM	COLO/SW	39	27	40	29	40	28	39	29	38	28	38	28	39	29	39	28	40	28	40	28	38	28	39	28
	WACM	WYO/CENT	60	48	60	48	59	48	59	49	60	49	60	50	60	50	60	49	60	48	60	48	60	49	60	50
	WACM	WYO/NE	61	50	62	50	62	50	62	52	61	51	61	51	61	51	62	50	63	51	62	50	63	52	62	51
	WACM	WYO/SE	53	41	53	42	53	42	53	42	53	42	53	42	53	43	54	42	54	42	54	42	52	42	53	42
	WACM	YTBIGHRN	72	61	72	61	72	60	73	63	74	64	74	64	74	64	73	61	73	61	73	61	73	63	74	64
	WALC	BLYE	14	3	14	0	14	0	13	2	14	0	14	0	14	3	15	0	7	0	15	0	14	0	14	0
	WALC	CALPINE	16	4	16	0	16	0	14	4	14	0	14	0	14	4	17	0	17	0	16	0	15	0	15	0
	WALC	HOOVER	16	4	16	0	16	0	14	3	14	0	14	0	14	3	16	0	16	0	16	0	14	0	14	0
	WALC	SUN	18	7	18	7	18	7	17	6	17	6	17	7	17	7	19	7	19	7	19	7	18	7	18	7
	WALC	WALCDAVS	16	4	16	0	16	0	14	4	14	0	14	0	14	4	16	0	16	0	16	0	15	0	15	0
	WAUW	WAUM	82	70	82	70	81	70	83	72	83	73	83	73	83	73	82	71	83	71	82	70	83	72	83	73

AESO - Alberta Electric System Operator
AZPS - Arizona Public Service Company
AVA - Avista Corporation
BANC - Balancing Authority of Northern California
BPAT - Bonneville Power Administration
BCHA - British Columbia Hydro Authority
CISO - CAISO
CFE - Comision Federal de Electricidad
DEAA - Arlington Valley, LLC
EPE - El Paso Electric Company
GRMA - Gila River Power, LP
GRIF - Grith Energy, LLC
IPCO - Idaho Power Company
IID - Imperial Irrigation District
LDWP - Los Angeles Department of Water and Power
GWA - NaturEner Power Watch, LLC
NEVP - Nevada Power Company
HGMA - New Harquahala Generating Company, LLC
NWMT - NorthWestern Energy
PACE - Paci-Corp East
PACW - Paci-Corp West
PGE - Portland General Electric Company
PSCO - Public Service Company of Colorado
PNM - Public Service Company of New Mexico
CHPD - PUD No. 1 of Chelan County
DOPD - PUD No. 1 of Douglas County
GCPD - PUD No. 2 of Grant County
PSEI - Puget Sound Energy
SRP - Salt River Project
SCL - Seattle City Light
SPPC - Sierra Pacific Power Company
TPWR - City of Tacoma, Department of Public Utilities
TEPC - Tucson Electric Power Company
TIDC - Turlock Irrigation District
WACM - Western Area Power Administration, Colorado-Missouri Region
WALC - Western Area Power Administration, Lower Colorado Region
WAUW - Western Area Power Administration, Upper Great Plains West
WWA - NaturEnur Wind Watch, LLC

Source: http://www.wecc.biz/committees/StandingCommittees/OC/UFAS/Shared%20Documents/Forms/AllItems.aspx.

N.B.: Only 28 major balancing authority areas with data are shown above. The following balancing authority areas are not shown but are considered to be in the North scheduling hub: CHPD, GCPD, GWA, TIDC, and WWA. The following are considered to be in the South scheduling hub: DEAA, GRIF, GRMA, HGMA, and TEPC. BANC is a special consideration and is part of the North scheduling hub. SPPC is also a special consideration and is part of the South scheduling hub as discussion in footnote 38.

Appendix 3: detailed calculation of hub price

Assumptions: A two intertie (T1 and T2), lossless world with one generator per BAA (BAA1 and BAA2) and both BAA's are in the North Scheduling Hub.

The following notation is used in this Appendix:

$SF_{BAA1,t1}$ is the aggregate shift factor of BAA1 with respect to intertie T1

$SF_{BAA1,t2}$ is the aggregate shift factor of BAA1 with respect to intertie T2

$SF_{BAA2,t1}$ is the aggregate shift factor of BAA2 with respect to intertie T1

$SF_{BAA2,t2}$ is the aggregate shift factor of BAA2 with respect to intertie T2

$SF_{Nhub,t1}$ is the aggregate shift factor of North Hub with respect to intertie T1

$SF_{Nhub,t2}$ is the aggregate shift factor of North Hub with respect to intertie T2

µ1p is the shadow price of the physical flow constraint on T1

µ2p is the shadow price of the physical flow constraint on T2

µ1s is the shadow price of the scheduling constraint on T1

µ2s is the shadow price of the scheduling constraint on T2

Recall, LMP = (System Marginal Energy Cost) + (Marginal Congestion Cost) + (Marginal Loss Cost). The contribution from each binding constraint to the MCC is the negative product of the shift factor (SF) and the shadow price (µ). The LMPs for each BAA is calculated just like internal nodes.

$$\text{BAA1 LMP} = (\text{SMEC}) + (SF_{BAA1,t1} * \mu 1p + SF_{BAA1,t2} * \mu 2p) + (0)$$

$$\text{BAA2 LMP} = (\text{SMEC}) + (SF_{BAA2,t1} * \mu 1p + SF_{BAA2,t2} * \mu 2p) + (0)$$

Note that the shadow price is non-zero only when the constraint is binding at the optimal solution.

Assume that we expect 80% of the energy to come from generation in BAA2 and 20% to come from generation in BAA1.

GDF of BAA1 = 20%

GDF of BAA2 = 80%

The North Hub is calculated as the weighted average of these two BAAs.

North Hub = [SMEC + $SF_{BAA1,t1}$ * µ1p + $SF_{BAA1,t2}$* µ2p] * 20% + [SMEC + $SF_{BAA2,t1}$ * µ1p + $SF_{BAA2,t2}$ * µ2p] * 80%

Which is the same as:

North Hub = SMEC + $SF_{Nhub,t1}$ * µ1p + $SF_{Nhub,t2}$ * µ2p

where the aggregate shift factors for the North Hub are the average of the BAA shift factors weighted by the GDFs.

If the scheduling constraint on an intertie also binds, then that intertie price is bound by an extra constraint, so the hub price separates for T1 and T2.

North $Hub_{T1price}$ = SMEC + $SF_{Nhub,t1}$* µ1p + $SF_{Nhub,t2}$* µ2p + µ1s

North $Hub_{T2price}$ = SMEC + $SF_{Nhub,t1}$* µ1p + $SF_{Nhub,t2}$* µ2p + µ2s

This calculation can be repeated for South Hub. The aggregate shift factor of South Hub with respect to each of the interties will be different than North Hub but the shadow prices of the physical flow constraints and the scheduling constraints with respect to T1 and T2 will be the same.

Attachment D – Addendum to Draft Final Proposal

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

California ISO
Shaping a Renewed Future

Full Network Model Expansion

Draft Final Proposal Addendum:

Pre-implementation Analysis

January 23, 2014

I. Executive summary

This paper describes the pre-implementation analysis that will be conducted for the Full Network Model (FNM) Expansion initiative. Specifically, the analysis will be a powerflow-based modeling assessment that will use the methodologies described in the draft final proposal as applied to actual days' market data prior to implementation to show the difference between the current and expanded FNM modeling. The end results will compare the modeled versus actual unscheduled flow for a set of representative days for the following four interties: (1) California-Oregon Intertie; (2) Palo Verde; (3) Eldorado-Mead; and (4) Victorville-Lugo. The end results will also compare results for representative internal constraints. The results will be provided in a briefing to the ISO Board of Governors at the September 2014 meeting.

II. Modeling assessment

There are two main activities of the modeling assessment. The first is the validation of base schedule inputs and the second is the core rerunning of historical market runs. The metric used to measure whether the FNM expansion enhancement is functioning as intended will be a comparison between modeled and actual unscheduled flows. The validation of base schedule inputs will serve as an important tool to calibrate the ISO's modeling to improve this metric. These two activities will be somewhat iterative and will rely on the calibration tools described in Section III.

a. Activity 1: Preliminary base schedules validation

This activity will validate the input data used for calculating base schedules. The ISO is currently working with the WECC Reliability Coordinator and our vendors to collect the data. The sources for each component of the base schedules are described in the draft final proposal and the calibration analysis will focus on the demand forecast, net scheduled interchange, and the generation and load distribution factors.[1] Specifically, the hourly demand forecasts from the WECC Reliability Coordinator will be compared against actual hourly demand by BAA. The net scheduled interchange by BAA pair will be retrieved via the WECC Interchange Tool. The ISO will receive the data by BAA pairs. During the validation, the ISO and its vendors will compare data available in the morning (approximately 9 am) with historical tag data. The historical tag data will form the foundation of a forecast and the morning data will be adjusted to the forecasted level of interchange. The ISO will track the accuracy of the morning projections against the historical tag data. In analyzing the historical tag data, the ISO will look at both historical data based on the day-ahead tag submission deadline (at 3 p.m.) and all tags submitted by the real-time deadline (20 minutes before flow). Lastly, the generation and load distribution factors for each modeled BAA will be adapted from the State Estimator solutions and will be saved and maintained in a library, similar to the existing process for the load distribution factors for the ISO LAPs.

[1] See Sections 6.1 and 6.2.

Timing: Data collection for this activity has already started and is targeted for preliminary completion by July 2014. The preliminary validation does not need the software code. When the second activity of the modeling assessment begins, the ISO will continue to validate the source data mentioned above and use the calibration tools as necessary. Therefore, this will be an iterative process in calibrating the inputs data used for calculating base schedules.

b. Activity 2: Rerunning production savecases

The modeling assessment will rerun production savecases with the expanded FNM software functionality enabled. This means that the ISO will take a save case of an actual market day and rerun the optimization for the entire day with the base schedules and the expanded FNM software functionality to calculate the resulting unscheduled flow due to base schedules. The goal of this activity is to show that the calculated unscheduled flows provide a reasonable estimate for the actual unscheduled flows that materialize in real time and ignored in the existing day-ahead market solution – recognizing of course that any significant outages of generation or transmission in real-time could impact the actual unscheduled flows and consequently the accuracy of the day-ahead estimate. The comparison will be as follows:

Data	Description of activity	Output
Day-ahead savecase	ISO will use the day-ahead savecase from each selected day as the starting point because it has no representation of unscheduled flow	No output
Day-ahead savecase with FNM expansion code and base schedules	Using the selected day-ahead savecases, rerun each through optimization with FNM expansion initiative changes	Calculated unscheduled flow on selected interties
Real-time unscheduled flow	Retrieve actual unscheduled flow on the selected interties for the same selected days	Actual unscheduled flow on selected interties

Since there are numerous changes scheduled for Spring 2014, it is most efficient to rerun savecases after these changes are implemented. Therefore, the pool of candidate savecases is limited to those after the Spring 2014 implementation. The ISO will select savecases from two timeframes:

- Test days rerun
    - Time: Spring implementation start (estimated April 1) to market simulation start (estimated July 8)
    - Purpose: From within this timeframe, select a variety of test days with normal or “stress” conditions to rerun the day-ahead savecases. These test days will provide the ISO a range of outcomes to help us benchmark and gain experience with the calibration tools and apply them to the daily reruns.
- Daily reruns

- Time: Market simulation start and ongoing
- Purpose: Rerun each day-ahead savecase starting from market simulation using the lessons learned from the test runs. The reruns will occur on a daily basis with a short lag time. For example, on Day 3, rerun the day-ahead market *created* on Day 1 (for operating Day 2) and compare it to the real-time results from Day 2. The ISO will rerun as many days as possible leading up to Fall 2014 implementation. In preparation for a briefing to the ISO Board in September, the results of this exercise will reflect analysis from the beginning of the market simulation to approximately mid-August. The ISO will continue to rerun daily savecases in a similar manner even after go-live to further refine its calibration methodology.

The analysis will be conducted with a focus on the following four interties: (1) California-Oregon Intertie; (2) Palo Verde; (3) Eldorado-Mead; and (4) Victorville-Lugo. We believe these interties provide a good sample of major unscheduled flow concerns. The analysis will also analyze modeled versus actual unscheduled flow on representative internal constraints.

Timing: Data collection for this activity starts at Spring 2014 implementation. During this period, the ISO will also decide on the test days to rerun. When the software code is stable on the ISO system around the July 8 market simulation, the rerunning of the selected savecases (both test days and daily reruns) will begin. During these reruns, the ISO will iterate between the validation of base schedule inputs and rerunning savecases using the calibration tools described below. In order to provide a Board briefing in time for the September 18-19, 2014 meeting, the results the ISO will provide includes the test days reruns and the daily reruns from the start of the analysis till approximately mid- to late-August. Calibration of inputs will continue up to and after go-live of the full network model functionality.

III. Calibration tools

The draft final proposal provided a non-exhaustive list of calibration tools and techniques the ISO can use in this modeling assessment and after implementation. Specifically, the draft final proposal notes that the demand forecasts will be compared to a historical analysis of actual demand, and the ISO can further fine tune the demand forecasts if needed by scaling the forecast up or down. Similarly, either the net scheduled interchange or the base schedules may be adjusted to neutralize their impact. In the case of net scheduled interchange, the adjustment would be in response to observed or perceived irregularities caused by the inclusion of base schedules. The problem may be isolated to a single net scheduled interchange or it may be more wide-spread. Adjusting the net scheduled interchange (but keeping the demand forecasts and setting the generation to the sum of interchange and demand) may be enough to adjust the unscheduled loop flow to resolve identified issues. The ISO will work with its vendors to develop a mechanism to adjust the net scheduled interchange, which will affect pairs of BAAs while not adjusting the schedules for the Energy Imbalance Market Entities. In summary, the adjustments can be made to modify or neutralize the impact of net scheduled interchange and may be applied to specific pairs of BAAs or more wide-spread. Under a more extreme scenario, the entirety of the base schedules (demand, generation, and net scheduled interchange) can be adjusted to modify or neutralize its impact. This would be done under extreme circumstances as it would affect the power flow solution of the Energy Imbalance Market entities. Note that these broad adjustment techniques are in addition to the validation and potential adjustment of the demand forecasts. The ISO can decide to adjust several or all of the BAAs as the situation requires. Should the base schedules be significantly modified or its impact neutralized, the ISO will develop a mechanism to compensate for the lack of base schedules (such as compensating for voltage and losses).

Attachment E – Market Surveillance Committee Opinion

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

Opinion on

Implementation of the Full Network Model

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair
Shmuel S. Oren, Member

Members of the Market Surveillance Committee of the California ISO

Adopted January 30, 2014

Executive Summary

The Market Surveillance Committee (MSC) of the California Independent System Operator (ISO) has been asked to provide an opinion on the California ISO's proposal for implementation of a Full Network Model for selected external balancing authority areas.[1]

In the body of this opinion we provide a detailed discussion of two issues:

- The use of the expanded full network model to improve the representation of loopflows in the California ISO day-ahead market; and
- The determination of schedules and prices for interchange transactions with adjacent balancing authority areas using this expanded full network model while continuing to model interchange as sourced on the tie lines connecting the California ISO with adjacent balancing authority areas.

We conclude that testing and implementation of a full network model is an important, indeed, essential first step on the road towards better regional integration and more accurate system modelling. These modelling improvements are necessary in order to achieve the goals of the Energy Imbalance Market as well as to comply with obligations stemming from the September 8, 2011 blackouts. We expect that a successful implementation will help to reduce the cost of meeting load in real-time as well as the energy market imbalance charges currently borne by California load. We stress, however, that creating and testing the full network model is likely to be a difficult and complex task. Other ISOs have similarly attempted or are currently attempting to represent flows outside their areas, and have experienced serious challenges in improving the accuracy of their estimates.

[1] California ISO, <u>Full Network Model Expansion</u>, Draft Final Proposal, December 30, 2013, www.caiso.com/Documents//DraftFinalProposal-FullNetworkModelExpansion.pdf

We therefore fully support the steps proposed in in this initiative, with the recognition that the CAISO must remain flexible in the specifics of its implementation. At this time it is impossible to fully predict what the results of each step of the process will be. However, given the experiences of other ISOs, it is reasonable to expect that the CAISO will be successful in developing an improved modeling of loopflows but that the results of the initial efforts will need to be carefully monitored and followed by further adjustments.

Given the uncertainties, it is critical that the CAISO have in place a plan for testing, adaptation, and calibration of the modeling. There also needs to be broadly accepted metrics and standards for defining what constitutes improvement in the representation of loopflows. The Draft Final Proposal contains a well thought out process for adjustments and a reasonable set of metrics. The CAISO has recently posted an addendum that more fully describes their planned approach to developing and testing the Full Network Model prior to implementation.[2] We therefore believe it is time to take the first steps toward better integration, as the later steps cannot be possible without the first.

Besides expressing strong support for the proposal in this opinion, we also discuss five sets of stakeholder concerns, and conclude that none of them are a sufficient reason for delaying or significantly revising the plan for developing and testing the full network model. We also identify a number of reasons why predictions of loopflows by the full network model may not be completely accurate, one important reason being the continued representation of interchanges with some balancing areas as injections or withdrawals at interties. However, these possible sources of inaccuracy can only be assessed and corrected for if development and testing of the full network model proceeds now.

1. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to provide an opinion on the ISO's proposal for implementation of a full network model (FNM) of selected external balancing authority areas.[3] The full network model would allow explicit modeling of loopflows on the California ISO transmission system from generation and load located outside the CAISO balancing authority area, potentially enabling the CAISO to decrease the cost of meeting load as well as to reduce real-time congestion rent shortfalls. In addition, the proposed implementation of at least some elements of the full network model is a necessary step for the implementation of the Energy Imbalance Market (EIM) with PacifiCorp in October 2014.

These issues have been discussed in MSC meetings in Folsom on September 6 and November 15 2013, and January 16, 2014. In addition, MSC members have participated in stakeholder calls

[2] See California ISO, Full Network Model Expansion, Draft Final Proposal Addendum: Pre-Implementation Analysis, January 23, 2014, www.caiso.com/Documents/Addendum-DraftFinalProposal-FullNetworkModelExpansion.pdf .

[3]California ISO, Full Network Model Expansion, Dec. 30, 2013, *op. cit.*.

discussing the Full Network Model on June 18, September 18, November 4, December 5, 2013, and January 7, 2014.

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The remainder of this opinion is organized as follows. Section 2 reviews the most recent CAISO proposal. We then discuss two of its features in detail in Sections 3 and 4, including stakeholder concerns that have been expressed about those features.

2. The CAISO Proposal

The CAISO full network model proposal has four main elements:

1. Extend the network topology represented in the CAISO's models to include the transmission systems of all directly interconnected balancing authority areas, the balancing authority areas involved in the September 8, 2011 blackout, EIM participants, and the transmission networks of some additional balancing authority areas needed to model the flows on the transmission systems of the EIM entities and the September 8 systems, specifically BPA, Idaho Power and Salt River Project;[4]

2. Represent all net interchange among the modeled balancing authority areas;

3. Represent internal generation and load on the systems of the September 8 entities, the EIM entities and BPA, Idaho power and Salt River Project; and

4. Utilize the extended network topology and representation of net interchange, generation and load to better model load and generation on other balancing authority systems that create loopflows on the CAISO transmission system. These steps thereby enable the CAISO to take account of predictable loopflows on the CAISO transmission system in clearing the ISO's day-ahead market.

Note that the CAISO would continue to model and price interchanges with external balancing authority areas that do not either join the EIM or enter into an interchange scheduling agreement with the CAISO as if the power was sourced or sunk at points on the tie lines with the CAISO. However, the expanded network model would be used to calculate the flow impacts of those interchange transactions in order to determine the congestion component of locational marginal prices, and with this improved representation of interchange flows, the California ISO would enforce physical transmission limits on tie lines.[5]

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[4] It is our understanding that the network topology included in the full network model will include almost all of the WECC transmission system, the main exceptions being the transmission systems in Alberta, British Columbia and Montana.

[5] For instance, such an interchange would be modeled as an injection at the relevant tie line bus. Using the FNM to represent the resulting flow impacts would likely result in much (perhaps most) of the flow coming into the CAISO directly over that tie line, but because of Kirchhoff's laws, a significant portion would flow through non-CAISO lines in the WECC network and then ultimately into the CAISO over other tie lines. This implies that compared to the present CAISO network representation (radial interties), less physical flow would be modeled as coming in directly over the scheduled tie line.

The first element of the full network model is reliability driven and includes improved network modeling not only of the systems directly involved in the September 2011 blackout but also of other systems that the CAISO needs to include in the model in order to accurately represent flows impacting the systems involved in the blackout.

This first element is also essential to implementing the EIM with PacifiCorp and includes improved network modeling of the PacifiCorp balancing authority areas and of other transmission systems that the CAISO needs to include in the model in order to accurately represent flows on the PacifiCorp system and calculate the impact of changes in PacifiCorp-CAISO interchange on other transmission systems. In addition to enabling EIM implementation with PacifiCorp, and providing better modeling of the September 8 entities, the extended network topology will help the CAISO to better model the impact of external generation and load on the California transmission system, thereby improving reliability.

We do not address this first element in detail in this opinion but note that the extension of the CAISO network model to encompass a broad region outside the CAISO transmission system is consistent with the scope of the network models used by the eastern ISOs. Indeed, even the old New York power pool network model that was used in its real-time dispatch program extended far outside New York, with the reference bus for this model located at Browns Ferry, Tennessee.

In the next section, we discuss five sets of stakeholder concerns that have been raised about the other three elements of the proposal, which address the modeling of loopflows and interchange. In the fourth section we discuss the potential consequences of the design for modeling of interchange transactions of parties not joining EIM or entering into an interchange scheduling agreement.

3. Stakeholder Concerns with Extending the Network Model to Other Balancing Authority Networks in Order to Improve Loopflow Estimates

The second, third and fourth elements of the full network model initiative are intended to better represent the impact of loopflows on the California ISO system and allow better scheduling in the ISO’s day-ahead (IFM) and real-time (RTPD) markets. This improved modeling of loopflows will benefit CAISO and EIM rate payers by reducing congestion rent shortfalls, reducing the production cost of meeting load, and improving reliability by enabling the CAISO to take these loopflow impacts into account in forward unit commitment and interchange scheduling decisions.

The CAISO believes that a material portion of congestion rent shortfalls (real-time congestion offset costs) are due to day-ahead schedules that turn out to be infeasible in real-time (unless accommodated by counterflow through out-of-merit redispatch of generation within the CAISO). These infeasibilities occur because of loopflows that reduce the transfer capability available to the CAISO for use in meeting ISO load.[6] By better modeling these loopflows in the day-ahead market, the CAISO will reduce real-time congestion rent shortfalls. Day-ahead market schedules will be better aligned with the transfer capability actually available for use in real-time. However, the modeling of loopflows in the day-ahead market will not preclude the CAISO from dispatching generation to fully utilize the transmission system in real-time if loopflows are lower than projected in a particular period. This modeling refinement will also reduce the production cost of meeting CAISO load by better aligning the day-ahead unit commitment with the transfer capability likely to be available in real-time, enabling load to be met at lower cost through improved unit commitment and a more cost-effective scheduling of net interchange. Finally, by improving the representation of next day operating conditions external to the CAISO transmission system and their impacts on the CAISO system, the modeling of loopflows will also contribute to improved reliability for CAISO transmission customers.

Another benefit of better loopflow modeling in the day-ahead market will be reductions in real time congestion rent shortfalls. Those shortfalls have declined substantially in 2013 relative to 2012, which the Department of Market Monitoring attributes in part to "efforts to address systematic modeling differences between day-ahead and real-time including better alignment of day-ahead and real-time transmission limits."[7] Better projections of loopflows from the full network model will be another step in the process of improved modeling by the CAISO that has materially reduced congestion rent shortfalls in 2013 relative to 2012.[8]

The California ISO plans to use a number of sources of data to model the base flows used to project expected loopflows. These data will include information provided by the September 8 entities, information provided by the balancing authority areas participating in the EIM, information available from WECC, voluntary agreements with individual balancing authority

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[6] See, for example, California ISO, Department of Market Monitoring, Q3 2013 Report on Market Issues and Performance, November 14, 2013, pp. 31-32; Q2 2013 Report on Market Issues and Performance, August 21, 2012, p. 22; and the 2012 Annual Report on Market Issues & Performance, pp. 92-96.

[7] See California ISO, Department of Market Monitoring, Q3 2013 Report on Market Issues and Performance, November 14, 2013, p. 31-32.

[8] It needs to be recognized in discussing these changes that the costs associated with real-time congestion rent shortfalls due to real-time loopflows are not fundamentally different from the costs that loopflows impose on a traditional vertically integrated utility. The congestion rent shortfalls due to loopflows are the difference between the projected cost of meeting load absent the loopflows (day-ahead market prices calculated without taking account of the loopflows) and the actual real-time cost of meeting load when transfer capability is reduced by loopflows.

A vertically integrated utility similarly has to meet its load at the higher real-time cost, rather than the lower cost that would have been possible absent the loopflows. The loopflows raise the cost of meeting load for both the California ISO's transmission customers and the traditional vertically integrated utility. The real potential for cost reductions is in making day-ahead commitments that recognize that the loopflows will be present in real-time. This can involve changes such as 1) avoiding the commitment of generation, that while low cost at full output, will be unable to be dispatched above minimum load in real-time because of loopflows; 2) by committing generation that, absent loopflows, would be higher cost but is lower cost than relying on quick start units to meet load when real-time loopflows reduce transfer capability; and 3) by not purchasing imports day-ahead that would be uneconomic to flow in real-time because of the high cost of the redispatch required to accommodate them.

areas, as well as recent operating experience, including flows observed in real-time during recent operating days.[9]

It is unknown at present to what extent the real-time loopflows impacting the CAISO transmission system are actually due to external balancing authority area dispatch and interchange transactions. The observed "loopflows" are simply the difference between the flows calculated by the CAISO model and those actually observed on the California transmission system. These loopflows could result from external balancing authority area dispatch and interchange transactions, but also could be caused by inaccurate modeling of the flow impact of the CAISO's interchange with external balancing authority areas due to the lack of a full network model. The discrepancies could even result from inaccurate modeling of the flow impacts of the CAISO's own generation dispatch because the external network is only partially modeled. Since the California day-ahead market and real-time dispatch do not utilize a full network model that includes external transmission systems, it has been impossible for the CAISO to even analyze the cause of the observed "loopflows," whether it is due to CAISO's internal generation and load, interchange with adjacent transmission systems, or generation and load on external systems.

Some stakeholders have expressed concerns about the modeling of loopflows in the day-ahead market using the Full Network Model initiative. We discuss five of these concerns below. First, some stakeholders worry that by taking account of these loopflows in the day-ahead market the CAISO will be foregoing its ability to manage these loop flows using WECC curtailment practices or that the CAISO will in some way be attempting to single-handedly "mitigate" or "accommodate" WECC-wide loopflow impacts. Second, some are concerned that the CAISO would need to calibrate its full network model to better account for predictable loopflows and thereby reduce congestion rent shortfalls relative to the current practice of ignoring potential loopflows in clearing the day-ahead market. In particular, a number of stakeholders have expressed a concern that absent an adequate calibration process, the CAISO would implement modeling changes that reduce, rather than improve, the accuracy of the day-ahead market in terms of projecting real-time conditions and could thereby cause day-ahead and real-time prices to diverge further. Third, one stakeholder has argued that modeling both contract path scheduling limits and physical pre- and post-contingency transmission constraints on tie-lines will be unduly conservative and thereby restrict imports unnecessarily. Fourth, some stakeholders appear to have expressed a view that the CAISO should choose what loopflows to model in the day-ahead market depending on whether modeling particular loopflows are projected to reduce or raise day-ahead market prices paid or received by particular market participants. Fifth, there has been discussion of whether the enforcement of physical transmission constraints on tie lines in the day-ahead market would undermine incentives for cost-reducing transmission investment relative to the current market design.

We discuss each of these stakeholder concerns in the following subsections.

[9] Full Network Model Expansion, Draft Final Proposal, December 30, 2013, pp. 16-18.

3.1 Concerns about Management of Loop Flow Impacts

We understand the concern expressed by market participants over whether the CAISO might choose to voluntarily forgo use of the transmission system paid for by CAISO transmission customers in order to accommodate use of the CAISO transmission system by external balancing authority areas. However, we do not believe that this proposal would result in the CAISO foregoing the use of any truly available capacity. The modeling of flows associated with other balancing authority area transactions in the day-ahead market will not reduce the CAISO's ability to utilize WECC curtailment rules in real-time to the extent that such rules are applicable. The improved modeling of loopflows in the California day-ahead market does not change how the CAISO will dispatch the system in real-time. Rather, the proposal addresses the assumptions that the CAISO will make in determining financial schedules in the *day-ahead market* and in committing generation. The CAISO will dispatch generation to meet load at least cost in real-time irrespective of any loopflows modeled in the day-ahead market. The real-time dispatch will have to account for actual real-time loopflows but will be able to utilize any applicable WECC curtailment rules to reduce real-time loopflows and reduce the amount of real-time redispatch required.

Hence the issue is not whether the CAISO should make use of WECC curtailment rules in real-time but whether the CAISO should, in the day-ahead market, better represent the loopflows that it *cannot* curtail in real-time. Under the current system, the CAISO determines financially binding schedules in the day-ahead market without considering the expected level of the real-time loopflows that it will not be able to curtail in real-time. Disregarding those loopflows means that day-ahead market schedules may be infeasible in real-time, which can require the CAISO to resort to costly redispatch in real-time to manage flows on transmission constraints internal to the CAISO in order to accommodate day-ahead market schedules.

In addition, as the CAISO has discussed in multiple straw proposals, WECC rules do not provide the CAISO with the ability to curtail real-time loopflows on most elements of the its transmission system, even if the CAISO was able to identify the specific transactions causing those loopflows.[10] The exceptions are loopflows on the California Oregon Intertie (COI). The CAISO agrees that WECC procedures do not require them to accommodate all loopflows on COI and the CAISO proposes to take account of its ability to curtail loopflows on COI in real-time in modeling loopflows in the day-ahead market.[11]

Hence, while we agree that the CAISO should not incur costs in order to manage loopflows that it can curtail in real-time, this is not what we believe the CAISO proposes. On the contrary, it is our understanding that the CAISO proposes to model the loopflows that it is *not* able to curtail in real-time, either because it lacks a mechanism to curtail them or because of difficulties in identifying the source of the loopflows. Even in eastern markets where transmission loading

[10] See Full Network Model Expansion, Second Revised Straw Proposal, October 30, 2013 pp. 14-15; Full Network Model Expansion, Third Revised Straw Proposal, December 5, 2013, p. 20; Full Network Model Expansion, Draft Final Proposal, December 30, 2013, pp. 20-23.

[11] Full Network Model Expansion, Draft Final Proposal, December 30, 2013, pp. 21-22.

relief (TLR) procedures provide the ISOs with a general mechanism for curtailing loopflows, the ISOs model the loopflows that cannot be curtailed and must be accommodated in real-time.[12]

3.2 Concerns about Day-Ahead Calibration and Impact on Day-Ahead/Real-Time Price Convergence

Some stakeholders have asked that the California ISO not move forward with implementation of the loopflow modeling elements of the full network model design unless the new model in fact, and not just in theory, performs better than the current design in predicting real-time flows. We agree with stakeholders that the CAISO needs to be sure that it is implementing a model that predicts loopflows better than the current design. We believe that this is the intent and goal of the CAISO full network model proposal. There is nothing in the full network model proposal that requires that the CAISO incorporate inaccurate loopflow projections in the day-ahead market. The proposal is for the CAISO to have the capability to model loopflows in the day-ahead market in those circumstances in which is it able to predict those loopflows with reasonable accuracy. Furthermore, the proposal is to reserve for the CAISO the discretion to use the best information available to it in order to model loopflows. If the information provided by some balancing authority areas does not enhance the CAISO's ability to accurately predict real-time loopflows, there is no obligation for the CAISO to use that information.

The CAISO has explicitly reserved the option to modify or not use base schedule data that it does not believe are sufficiently accurate and we support this element of the proposal.[13] The CAISO has also stated that it will not use any model of real-time loopflows in the day-ahead market that it does not believe will provide a sufficiently accurate representation of what will happen in real-time.[14] Hence, the Full Network Model design envisions that the CAISO will actively monitor the performance of the design to ensure that it is achieving its intended goal of improving loopflow forecasts, and we agree that it is important that the CAISO actively carry out this objective.

Once the extended topology of the Full Network Model is developed, the CAISO can begin using the data it has assembled to assess its ability of using that data in predicting real-time loopflows on binding constraints. In implementing this design, the CAISO needs to begin calculating the impact of its real-time market flows on frequently binding CAISO transmission

[12] See Footnote 16, *infra*, regarding Midwest ISO efforts to model loopflows in its day-ahead market.

[13] See Full Network Model Expansion, Draft Final Proposal, December 30, 2013, p. 16 ("The ISO will use the best available data and can use its own analysis to develop or modify base schedules if and when necessary"), p. 17 ("the ISO will rely on its own analysis and validation, for example, to true up or estimate missing information"), and p. 18 ("While the ISO intends to leverage the data made available by the Reliability Coordinator, we will also reserve the right to create, modify, or select amongst different data sources as appropriate").

[14] See *ibid.*, p. 18: "the ISO will be tracking the difference between scheduled and actual flows to understand whether or not the base schedules are effective. Based on these results, the ISO can calibrate the net scheduled interchange. In a more extreme approach, all of the base schedule (demand, generation, and net scheduled interchange) can be set to zero."

constraints prior to the implementation of the EIM and use of the full network model in operations. Such benchmarking will enable the CAISO to calculate the observed real-time loopflows (the difference between actual flows and market flows), and assess the extent to which it is able to predict these flows using the information available to the CAISO at the time it clears its day-ahead market. It is our understanding that the CAISO does not intend to model loopflows in the day-ahead market if it is unable to develop reasonably accurate predictions of their level.

The critical decision that needs to be made now is to move forward with development of the FNM and associated software, because the analysis of base schedules and loopflows along with the calibration of the model cannot be undertaken until the CAISO has developed, at least, an initial version of the network model and software.[15] Hence the CAISO needs to make an initial decision to move forward with the network model implementation in order to be able to carry out benchmarking analyses and evaluate alternative methods to model loopflows on the full network model.

The proposed approach of the CAISO for estimating loopflows and modeling them in the day-ahead market would not be unique to the CAISO. It is also used by those Eastern ISOs who are extensively impacted by loopflows, such as MISO and PJM. The MISO had very large real-time congestion rent shortfalls during its initial year of operation (2005) which it substantially reduced during 2006 and 2007. It has continued to reduce congestion rent shortfalls in subsequent years through improved modeling of loopflows.[16]

The CAISO has committed to pre-implementation analysis and benchmarking to provide assurance to stakeholders that the model will be able to achieve its intended goals before the

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[15] See *ibid.*, p. 38 regarding the need to develop the full network model and software capabilities in order to carryout benchmarking analysis.

[16] See Potomac Economics, 2006 State of the Market Report the Midwest ISO, July 2007, which noted that "(b)ased on our review of the results in 2006, we conclude that the sizable reduction in congestion costs collected in the real-time market was due to improvements in the assumed loopflows that the Midwest ISO use in operating the day-ahead market" (p. 64). Similarly, see Potomac Economics, 2007 State of the Market Report for the Midwest ISO, p. 69, which refers to the success of the Midwest ISO in incorporating "reasonably accurate loopflow assumptions in the day-ahead model." In Potomac Economics, 2008 State of the Market Report for the Midwest ISO, pp. 67-68, it is noted that "(b)alancing congestion costs have declined since 2006 due to improvements made in the day-ahead modeling of loopflow and a general decrease in congestion in 2008." The Potomac Economics 2009 State of the Market Report for the Midwest ISO, pp. 75-77 states that "the lower costs in recent years are due to improvements made in the day-ahead modeling of loopflows and an overall decrease in congestion." Meanwhile, Potomac Economics 2010 State of the Market Report for the MISO Electricity Markets, June 2011, pp. 77-79 said that "(r)eal-time congestion costs were minimal, which is expected when modeling of the transmission system is consistent between the day-ahead and real-time markets." Further, Potomac Economics' 2011 State of the Market Report for the MISO Electricity Markets, June 2012 reported that "(r)eal-time congestion costs in 2011 … were a small share of total congestion costs collected by the MISO. These costs generally occur when the transmission capability available in the real-time market is less than was assumed. In 2011, real-time congestion costs were negative (*i.e.*, a real-time surplus) for the the first time" (p. 41), In 2012, real-time congestion rent shortfalls swung back to a small positive value, see Potomac Economics, 2012 State of the Market Report for the MISO Electricity Markets, June 2013, p. 47.

FNM is implemented.[17] We support this approach. The CAISO cannot provide this assessment unless it moves forward with this initiative. After the Full Network Model is implemented, the CAISO has committed to providing ongoing metrics to enable market participants to evaluate performance.[18] Stakeholders should be able to monitor the overall accuracy of the California's ISO's loopflow projections through occasional after-the-fact reports, perhaps by the Department of Market Monitoring. These reports could report aggregate results without disclosing the specific methods that the CAISO uses to predict the real-time loopflows on an individual constraint. The Department of Market Monitoring could choose the criteria it applies to evaluating CAISO performance, but some obvious approaches would be to calculate the frequency and magnitudes of over- and under-projections of loopflows, and to evaluate the cost of those errors using day-ahead market and real-time constraint shadow prices.

Similarly, while it is important that the CAISO test the accuracy of its loopflow projections and use these tests to adjust its modeling methods so as to improve the accuracy of its projections, the goal of developing more accurate loopflow projections will not be served by requiring the CAISO to specify in advance all of the methods it might use to adjust its models to better calibrate projected loopflows with actual loopflows. The CAISO needs to have the flexibility to develop appropriate adjustments as it evaluates the quality of its projections and gains an understanding of the sources of errors in its projections. CAISO stakeholders need to hold the CAISO accountable for the accuracy of its projections but allow it flexibility in the methods it uses to develop those projections.

We must recognize that loopflows, relative to predictions, will vary from day to day just as real-time load varies from day to day. Forecasts are rarely perfect. Some market participants have predicted that it will be harder to accurately project loopflows in the WECC than in the eastern interconnection, for example due to difficulties in predicting hydro operations. It is possible that this will turn out to be the case. But the issue is not whether the CAISO's loopflow projections will always be perfect but whether they will be more accurate, on average, than no forecast at all. The analysis of virtual bids in Department of Market Monitoring annual and quarterly reports suggests that market participants are able to submit bids targeting constraints that will bind more tightly in real-time than day-ahead because of loopflows. If market participants are able to predict these impacts better than the current day-ahead market model, then these loopflows must be predictable to some degree.[19]

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[17] See Full Network Model Expansion, Draft Final Proposal, December 30, 2013, Section 11, pp. 38-39.

[18] *Ibid*., p. 39.

[19] See California ISO, Department of Market Monitoring, 2012 Annual Report on Market Issues and Performance, p. 97: "DMM estimates that about $70 million out of $95 million of real-time congestion revenues paid to virtual positions in 2012 resulted from excess day-ahead power flow on constraints whose power flow limits were reduced between the day-ahead and real-time markets." If virtual bidders can predict these deratings well enough to submit these bids, the California ISO should be able to predict them. The reduction in real-time congestion rent shortfalls during 2013 suggests that these loopflows can be predicted and reflected in the day-ahead market, and the FNM will provide another incremental improvement in the modeling of loopflows that impact transmission constraints on the CAISO grid.

Vertically integrated utilities elsewhere in the WECC do not have binding day-ahead market financial schedules. As a result, the way they take account of predictable loopflows is less visible than modeling assumptions in the CAISO's day-ahead market. However, it is reasonable to assume that other WECC utilities impacted by predictable real-time loopflows schedule their imports while accounting for the liklihood that those transactions would have to be cut in real-time (or require costly out-of-merit dispatch to accommodate in real-time) due to loopflows. Hence, we do not believe that the steps the CAISO proposes to take to account for the impact of predictable loopflows is fundamentally different from what other WECC system operators and utilities do to protect their ratepayers from the financial and reliability consequences of such loopflows.

There is no reason to require that the CAISO act as a helpless victim that enters into financially binding day-ahead market schedules that it, and market participants, know will have to be settled at a loss in real-time. Furthermore, the CAISO should not be required to accommodate interchange transactions with costly out-of-merit redispatch because the day-ahead market schedules do not reflect the impact of predictable loopflows. As we just noted, the predictability of these flows is shown by the fact that virtual bidders have been able to submit paired virtual demand/supply bids that generate significant profits because of differences between day-ahead and real-time prices that are believed to be due to real-time constraint deratings associated with real-time loopflows.[20]

It should be kept in mind that the use of the full network model will have several offsetting effects. All of these effects will tend to reduce production costs but only one of these effects will tend to reduce congestion rent shortfalls. First, use of a broader network model of external balancing areas and the modeling of their dispatch and external transactions may predict additional loopflows that will use up transmission capacity on the CAISO transmission system. Second, however, the use of the full network model may also at times involve modeling counterflows on the CAISO transmission system than will reflect predictable counterflows that will increase transfer capability, allowing greater use of transmission to be scheduled in the day-ahead market. Third, use of the network model will also cause the dispatch of CAISO schedules in the day-ahead market to partly flow over external paths, as it will in real-time, thereby reducing the calculated market flows on some internal CAISO lines. Hence, the combined effects are not uniformly towards increased congestion on all lines in the day-ahead market but likely a mixture of both increased and decreased congestion.

Overall, we agree with stakeholders that the CAISO should use the full network model and the associated base schedules to improve, not worsen, the modeling of real-time congestion in the

[20] Some stakeholder comments suggest that there is some confusion regarding the role of virtual bids in contributing to real-time congestion rent shortfalls. The source of real-time congestion rent shortfalls is not constraints that bind in the day-ahead market because of virtual bids, but rather these shortfalls are due to constraints that bind in the real-time dispatch, which does not include virtual transactions, only physical generation and load. Moreover, there can be congestion rent shortfalls regardless of whether or not a constraint binds in the day-ahead market. Real-time congestion rent shortfalls arise when the market flows scheduled in the day-ahead market exceed the market flows that can be accommodated on the constraint in real-time. This is likely to be the case if the constraint is impacted in real-time by material loopflows that were not modeled in the day-ahead market.

day-ahead market. However, this goal can only be achieved if the CAISO moves forward with developing and testing the full network model and with obtaining and evaluating the information it will use to develop base schedules for external control areas. We also agree with stakeholders that, conceivably, the information that the CAISO will receive in the day-ahead market from the WECC may turn out not to be very useful in predicting real-time loopflows. But in order to determine which data and methods are useful (or not), the CAISO needs to move forward with this initiative. The time to discuss which data and methods lead to good predictions is not now, but after the CAISO has implemented the full network model in a testing environment and has had an opportunity to evaluate its ability to predict real-time loopflows using various data and models. It is not apparent to us how the CAISO can develop good models for predicting loopflows unless it starts somewhere.

3.3 Concerns about Effect of Day-Ahead Enforcement of Physical Constraints on Imports

A third stakeholder concern is that enforcing physical constraints (*i.e.*, the underlying pre- or post-contingency limits) on tie lines in the day-ahead market model, in addition to enforcing scheduling limits, will artificially restrict imports. We do not agree with this concern as a general issue. It is possible that there may be some circumstances in which modeling interchange as being sourced on the tie line will cause the model to systematically overstate total physical flows (the flows associated with scheduled net interchange, loopflows and perhaps loopflows associated with California generation and load). As we explained with respect to the second concern, if the use of particular data or modeling methods does not lead to good predictions of real-time line flows, then the CAISO needs to correct the modeling approach before implementing the full network model. And indeed, as we discuss at length above, this is what the CAISO proposes to do.

If there are particular tie lines on which the CAISO finds that it cannot accurately approximate the real-time physical flows with interchange modeled as sourced on the tie lines, then it could be in some cases that the best resolution would be to not enforce the physical constraint on that particular tie line. However, this is a decision to be made when it is determined that there is a modeling problem, and furthermore, that not enforcing a physical constraint is the best way to address that modeling problem. It is not a decision that should be made without regard to whether the modeling of physical flows is accurate or even understated.

There is nothing inappropriate about taking into account both flows on physical constraints and scheduling constraints in determining day-ahead or real-time prices. The CAISO already does this, taking into account the impact of interchange flows on physical constraints on all lines other than the tie lines. The price of power on all tie lines can be impacted in the current design both by the impact of the flows on physical constraints or on the scheduling constraints. The change proposed is simply to model the physical constraints on the tie lines themselves--which are not separately enforced in the day-ahead market today. Omitting physical constraints was sensible when the tie lines were modeled as strictly radial to the CAISO network, as the flows on the tie line scheduling and physical constraint would be the same. However, with the introduction of the full network model, the physical flows and the contract path flows will no longer be the same. If, by modeling the physical constraints on tie lines in the day-ahead market, the CAISO can better predict when a physical constraint will bind in real-time, then the CAISO ought to model that constraint, thereby accounting for the cost of the redispatch required to manage the congestion impact of interchange transactions in the day-ahead market price of those interchange transactions. The import supplier or export buyer can then decide whether or not it wants to schedule the transaction based on the day-ahead market price that reflects the actual value of the power to the CAISO system.

It is important to recognize that the interchange flows used to enforce the scheduling limit and physical constraint are not the same. The flows used to enforce scheduling limits are the contract path flows that flow entirely over the scheduled tie line. The flows used to enforce the physical constraint are the flows on the full network model. In the full network model, not all of the scheduled interchanges will flow over the tie line, and the flows on the physical constraint may also be impacted by the scheduled interchanges on other tie lines and by the dispatch of internal generation. Therefore, unlike the scheduling limit, the physical limit is not an absolute limit on the net interchange scheduled on a particular tie line. Rather, when the physical limit binds, the price of the imports scheduled on this path falls to reflect the cost of the redispatch required to accommodate those flows. Hence, enforcement of the physical constraint will generally not preclude interchanges from being scheduled up to the scheduling limits, but the cost of any required redispatch would reduce the value of those imports and would be reflected in the price paid for those imports. This is appropriate. The CAISO should not pay more for imports than their economic value, after taking account of the redispatch required to accommodate their impact on the ISO’s transmission constraints. The enforcement of the physical constraint on tie line flows may therefore, at times, reduce the price paid for imports, but this would be appropriate.

To summarize, there is nothing extraordinary or inconsistent about modeling physical constraints on tie lines. PJM has modeled physical tie line constraints for many years and does not model scheduling limits. The New York ISO has long modeled both physical constraints on lines and scheduling constraints, although these scheduling constraints apply to flows on interfaces, not individual lines.

Further, modeling physical constraints in combination with loopflows will not necessarily cause the physical constraint to bind at a lower level of interchange than the scheduling limit. Because the flows on physical constraints will be calculated on the full network model, the physical flows associated with interchange schedules will not be the same as the contract path flows used to enforce scheduling limits. It is possible that implementation of the full network model will provide evidence suggesting that particular scheduling constraints are currently set too low. This, however, would be evidence of problems with the WECC process for setting scheduling limits, not of the CAISO full network model design.

It is also possible that there will be some tie lines on which the way interchange is modeled would cause interchange flows on the line to be overstated. If such a situation is identified, the CAISO will need to either make changes that correct the predicted flows or perhaps not enforce the physical constraint. However, this is an empirical situation that needs to be addressed only if and when it arises.

3.4 Concerns about Impact of Modeling Loopflows Upon Day-Ahead Prices

A fourth concern that has been raised with the proposed modeling of loopflows is that their accurate representation in the day-ahead market would potentially raise prices for particular power buyers and/or lower the prices for particular power sellers. We agree that there is a likelihood that implementation of the full network model and more accurate modeling of expected loopflows may, in a given hour, raise the day-ahead market prices paid (or earned) by some and lower the prices paid (or earned) by others. We believe, however, that the CAISO should *not* base its modeling decisions on how that modeling would impact the prices paid by or to particular entities. This would be fundamentally inconsistent with the role of an *independent* system operator, would contradict the fundamental objective of maximizing market efficiency, and finally, would undermine confidence in CAISO markets.

To date, the CAISO has been able to effectively manage in real-time the impact of real-time loopflows. However, continuing to ignore expected loopflows in the day-ahead market increases reliability risks and appears to be inconsistent with the goals of the post-September 8 modeling changes, and particularly with recommendation 2 of the FERC/NERC joint staff report.[21] It would also undermine the goal of improved visibility and reliability.[22] A policy of selectively including those loopflows and changes in generation shift factors in order to reduce prices in a particular region would further increase reliability risks and defeat a major goal of the 2009 CAISO Market Redesign and Technology Upgrade, namely to align forward prices and schedules with actual system conditions.

Further, predictable inconsistencies between day–ahead and real-time prices not only incent virtual bids designed to take advantage of these differences, they will also impact the bidding behavior of physical market participants in ways that not only contribute to increased congestion rent shortfalls but can raise the overall level of market prices.[23]

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[21] See FERC staff and staff of the North American Electric Reliability Corporation, Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations, April 2012, p. 116, which states: “TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and Bas should take the necessary steps, such as executing non-disclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the regions for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.

[22] These reliability risks would be magnified if additional changes were made to discourage virtual bidders from submitting bids that cause these real-time constraints to more frequently bind in the day-ahead market. This is because virtual bids in such circumstances are contributing to maintaining real-time reliability by impacting the scheduling and commitment of additional generation within the region that will be constrained by transmission in real-time.

[23]For example, when the failure to model loopflows in the day-ahead market raises prices for imports day-ahead and decreases prices in real-time, the import supplier buys back its day-ahead schedule at a profit relative to the day-ahead market price. However, it is not necessarily making a profit unless the drop in the real-time price is larger than the sunk cost of the transaction. If the drop in the real-time price is not

Even if the CAISO was to embrace a goal of achieving specific price outcomes, it is not at all clear what that goal would be. Almost *any* change in modeling of loopflows or the impacts of the CAISO's dispatch will benefit some buyers and sellers and hurt others. What criteria should the CAISO use to decide which market participants it should seek to benefit by manipulating day-ahead market prices in the suggested manner?

Furthermore, the cost and revenues of power buyers and sellers depend not only on day-ahead market prices but also on which transactions are covered by longer-term contractual arrangements. With long-term contracts in the mix, adjusting the model of interchange to achieve specific short-term price outcomes may not even help the intended beneficiaries.

Last, to the extent that the power impacted by the modeling choices is not covered by a long-term power contract, artificially reducing the energy market revenues of generation may in the longer term simply require higher resource adequacy payments to keep needed generation in operation, while eliminating the price signal that might encourage lower cost entry at these locations. The resulting market inefficiency would increase the cost of serving load.

Overall, we do not agree that a criterion for evaluating changes in modeling should be whether they move day-ahead prices in a manner that benefits, or appears to benefit, particular market participants. The criterion should be whether the changes reduce overall production costs and converge day-ahead prices with expected real-time prices. This is our understanding of what the California ISO intends and we support that goal.

3.5 Congestion Pricing and Transmission Investment

A fifth topic of discussion with regard to the impact of the modeling of physical transmission constraints has been whether this change would adversely impact the efficiency of the incentives provided for expanding the transmission system for delivery of power into the CAISO. At this time we have not been able to identify any such adverse impacts.

It is perhaps possible that some transmission investments outside the CAISO system would create a contract path scheduling entitlement without increasing the physical transfer capability of the transmission system. In this circumstance, the enforcement of physical transmission constraints on interties in the day-ahead market could reduce the profitability of those transmission investments. However, this would not be an adverse impact, it would instead be an efficiency-enhancing impact. The CAISO should seek to disincent, not incent, transmission investments having such properties.

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this large, the real-time loopflows may cause import suppliers to offer supply at higher prices in the day-ahead market all the time, to cover the increased risk of not recovering the cost of transmission. Alternatively, suppliers could wait to buy transmission until real-time but then they would not be allowed to buy back their schedule at a profit. In that case, they would respond by offering supply at higher prices to cover the risk of having of real-time loopflows requiring them to sell power at a loss outside the CAISO.

It is also possible that as a result of scale economies and lumpiness in transmission investment, the size of some transmission expansions would need to be so large that they would completely eliminate transmission congestion for a number of years, making it difficult to finance those projects on a market basis (*e.g.*, awarding of congestion revenue rights). While this is a possibility, it is a possibility that exists whether the constraints being eliminated are scheduling limit constraints or physical transmission constraints. Therefore, the potential for this outcome is not related to the implementation of the full network model or enforcement of physical transmission constraints on the ties.

Finally, it is also possible that a new transmission investment on an intertie could increase transfer capability but not enough to eliminate congestion on a transmission constraint. Hence, while the scheduling limit and physical transfer capability might both rise, the price on the intertie would remain depressed because there would still be congestion. This could be the case if the binding constraint was either a scheduling limit or a physical transmission constraint. There is nothing unique about the enforcement of physical transmission constraints on the ties in this regard. Moreover, the incentive for such transmission investments would lie in the congestion revenue rights (CRRs) awarded to the entity funding the project, which should entitle the transmission investor to the difference between the internal CAISO price and the price at the intertie in the amount of the increase in transfer capability. It is possible that there are one or more imperfections in the CAISO's allocation of CRRs in such circumstances that ought to be addressed but that is also unrelated to the implementation of the full network model, nor is it related to the enforcement of physical transmission limits on tie lines in the day-ahead market.

Overall, we have not been able to identify any adverse impact on transmission expansion incentives from any element of the full network model design.

4. Modeling of Interchange Transactions on Tie Lines

Over the course of the FNM stakeholder process, the CAISO has changed the way it proposes to model interchange in response to market participant concerns. The second revised straw proposal called for the CAISO to model and price interchange not scheduled within the framework of either the EIM or an interchange scheduling agreement at the northern and southern scheduling hubs. The design in the draft final proposal instead calls for the CAISO to model interchange as sourcing or sinking on the tie lines, as it does today. This methodology described in the draft final proposal will likely provide some improvement in the modeling the impact of interchange on the CAISO transmission system because it will be applied to a network model whose topology will extend outside the CAISO transmission system. Nevertheless, because of how interchange is modeled, the flows modeled by the CAISO will likely differ systematically from the actual real-time flows created by interchange transactions.

Hence, while delaying the implementation of the originally proposed changes that would model interchange transactions at trading hubs and sourcing and sinking in balancing authority areas external to the CAISO rather than at points on the tie lines has avoided the need to resolve some issues prior to the initial implementation of the full network model, this change may complicate the CAISO's effort to develop a more accurate model of loopflows. Because the CAISO will be modeling the impact of interchange transactions more accurately than today but in a manner that may produce systematic errors in projected flows on the CAISO transmission system, the CAISO will need to distinguish differences between market and actual flows on its system that that are due to its mismodeling of interchange from differences due to the impact of other balancing authorities transactions on the CAISO transmission system.

The magnitude of the difficulties created by this approach will be known only when the CAISO begins testing the full network model and this magnitude may vary from line to line and with shifts in interchange patterns. This is an additional issue that the CAISO will have to address in calibrating the model to ensure that it provides better projections of real-time loopflows than the current system.

Attachment F – Board Memorandum

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market and Infrastructure Development

Date: January 30, 2014

Re: **Decision on full network model expansion**

This memorandum requires Board action

EXECUTIVE SUMMARY

Management is seeking Board approval of its proposal to expand the full network model used in the ISO market. This expansion consists of:

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

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

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

This proposal provides reliability and market efficiency benefits including:

- **Improved reliability:** Expanding the full network model will allow the ISO to more accurately model expected real-time conditions in the day-ahead timeframe by including unscheduled loop flow, outages, and contingencies. This aligns with Federal Energy Regulatory Commission and North American Electric Reliability Corporation recommendations after the September 8, 2011 southwest blackout that stated the ISO and other balancing areas should better coordinate their day-ahead planning.

- **Improved market efficiency:** The modeling improvements will provide more accurate market pricing by incorporating congestion caused by unscheduled loop flow and respecting the physical limits of the ISO's interties in the day-ahead market. It will also reduce infeasible schedules in the day-ahead market that result in expensive re-dispatch of resources in the real-time market. The modeling of the external network also supports the feasibility of energy imbalance market schedules.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposed full network model expansion, as described in the memorandum dated January 30, 2014; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

The full network model expansion provides visibility to external transmission systems and their impacts on the ISO's market processes. This will enable the ISO to more effectively dispatch and schedule resources on the ISO-controlled grid.

Background

In response to the major southwest blackout on September 8, 2011, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation cited the need for greater visibility and modeling of external networks in the day-ahead timeframe to ensure more reliable real-time operation. Meanwhile, the ISO has experienced significant uplift costs to re-dispatch resources in the real-time market to resolve unscheduled loop flows that were not modeled in the day-ahead market. Additionally, the energy imbalance market will have significant interactions with external transmission networks that will benefit from modeling unscheduled flows in the day-ahead market.

Objectives

Based on recommendations from the review of the southwest outage on September 8, 2011, the ISO identified two main areas for modeling improvements. The first is the lack of unscheduled loop flow modeling in the day-ahead market and the second is the inability to reflect outages and other security parameters of external transmission systems. Making these modeling improvements will improve reliability and produce more efficient market results.

Unscheduled loop flows occur because, outside of California, the balancing authority areas within the western interconnection rely on contract path scheduling between balancing areas. This assumes that electricity flows along a designated point-to-point path when in fact electricity flows over the path of least resistance. For example, a contract path schedule of 100 MW over intertie T1 may actually result in 80 MW of the schedule to flow over T1 and 20 MW of unscheduled loop flow over intertie T2. If the ISO does not account for the 20 MW of unscheduled loop flow on T2, it may accept ISO market schedules on T2 assuming this 20 MW of capacity is available, thereby creating infeasible schedules and potentially scheduling more energy to flow over the intertie than the physical limit.

Currently, infeasible schedules and the intertie's physical limits are managed in real-time when there is less flexibility to commit units, which may lead to re-dispatch of expensive generation or even exceptional dispatches to resolve the infeasibility. This can lead to real-time congestion offset uplift costs. These uplift costs occur when there is congestion and the market pays more than it charges to adjust generation. The difference is allocated to load. Alternatively, under Management's proposed full network model approach, the loop flow will be incorporated into the day-ahead market and the day-ahead market will produce feasible schedules with prices that more accurately reflect the conditions that will be experienced in real-time.

By expanding the full network model to include other balancing areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how that may affect the ISO market. Including these modeling improvements in the day-ahead and real-time markets will help the ISO create feasible schedules, enforce reliability, and accurately price market transactions.

Proposed methodology

In order to model unscheduled loop flows and incorporate reliability and outage information, Management proposes to include external balancing areas in the full network model to accurately enforce physical capacity limitations of the interties. Under Management's proposal, the ISO will eventually include all balancing authority areas in the western interconnection in its modeling, however, time and resource availability limits the modeling to a priority list of balancing authority areas for fall 2014 implementation. These balancing areas include the entities involved in the September 8, 2011 blackout and entities that are highly integrated with energy imbalance market entities. The energy imbalance market entities themselves will also be modeled consistent with the approach developed for the energy imbalance market. As time and resources allow, the ISO will model additional balancing areas deemed to have a significant impact on the ISO or the energy imbalance market entities.

Since unscheduled loop flows can result from almost any transaction in the interconnected grid, Management's proposal includes first modeling the demand, generation, imports, and exports of the priority balancing areas. The ISO will obtain the data needed for this modeling from a Western Electricity Coordinating Council database developed to coordinate reliability planning. By accounting for the unscheduled flow in the day-ahead and real-time markets, the ISO will be able to establish market schedules which will be feasible in real-time.

Management proposes to seek FERC authorization to model and enforce physical flow limits, as appropriate, on interties in the day-ahead so that the combination of unscheduled loop flow and flow from accepted market schedules do not exceed the physical capability of the line. One exception to this change is the California Oregon Intertie, where the ISO is the path operator. For the California Oregon Intertie, Management proposes to continue to enforce only the scheduling constraint in the day-ahead market and use the Western Electricity Coordinating Council's unscheduled flow mitigation procedure in the real-time market, as it does today. The mitigation procedures on qualified paths, which include the California Oregon Intertie, allow the ISO to curtail schedules causing unscheduled loop flow. The separate treatment for the California Oregon Intertie is a continuation of how the California Oregon Intertie is operated today and respects multi-party operating agreements in effect.

In line with these changes, the ISO will also improve its modeling of high voltage direct current transmission and true-up the underlying model used for congestion revenue rights with the expanded full network model.

Nexus with energy imbalance market

Though the impetus to expand the full network model did not come from the energy imbalance market implementation, accurate modeling of energy imbalance market entities depends on accurately modeling highly interconnected external systems. This is especially the case for PacifiCorp West, which relies on Bonneville Power Administration's transmission system. The full network model expansion will provide improved power flow solutions with greater awareness of external impacts on the combined ISO and energy imbalance market footprints. Therefore, the full network model expansion is scheduled to be implemented simultaneously with the energy imbalance market in fall 2014.

POSITIONS OF THE PARTIES

Stakeholders generally support the goal of expanding the full network model but have specific concerns with Management's proposed approach for modeling external balancing areas, which are discussed below. Management developed this proposal through an extensive stakeholder process and has reflected stakeholder input in the proposed approach. For example, Management originally proposed to model imports and exports as having sources and sinks distributed at locations outside the ISO balancing area. However, Management deferred this aspect of its proposal to a future separate stakeholder initiative based on stakeholder concerns with the potential impacts of such an approach.

The Market Surveillance Committee supports Management's proposal. The MSC's Final Opinion is attached for your reference.

The following addresses stakeholder positions raised during the stakeholder process. A detailed stakeholder comment matrix is also attached for reference.

Position 1: Some stakeholders requested additional analysis validating the ISO's proposed methodology. Specifically, some stakeholders are concerned that the external load, generation, and interchange data at the time the day-ahead market is run will not reflect all the transactions that are finalized later in the day.

Response: Management commits to analyze the results of the full network model functionality and demonstrate its accuracy prior to putting it into production. Management has provided stakeholders with a detailed plan for this pre-implementation testing and calibration. Management further commits to reporting back to the Board on the results of this analysis during its September 2014 meeting.

Position 2: A few stakeholders believe that a different subset of balancing authority areas should be additionally modeled and that the implementation should be separated from the energy imbalance market.

Response: Management believes modeling the identified priority balancing areas is sufficient for accurate unscheduled flow modeling. The modeling priorities for fall 2014 include balancing authority areas to support the energy imbalance market entities to obtain accurate power flow solutions.

Position 3: A few stakeholders were under the incorrect assumption that the proposed approach for limits on schedules and modeled flows on the California Oregon Intertie is counter to today's practices and agreements.

Response: The separate treatment the California Oregon Intertie is a continuation of today's practices and is not inconsistent with current practices and agreements. Moreover, it allows the ISO to use the Western Electricity Coordinating Council's unscheduled flow mitigation procedure in the real-time.

Position 4: One stakeholder opposes enforcing limits on physical flow over interties, in addition to the current limits on scheduled transactions over interties, because it will change the prices at the interties and will limit intertie schedules in the day-ahead market in a way that may not reflect market participants' scheduling priority in adjoining balancing areas. Instead, this stakeholder would prefer the ISO negotiate the limit for the total amount of day-ahead schedules that it can accepted for an intertie each day.

Response: The physical flow limit is already enforced in the real-time over the interties and is enforced both day-ahead and real-time within the ISO. The proposal extends this practice to the interties in the day-ahead so that the day-ahead model better reflects real-time conditions. Physical flow constraints exist regardless if they are in the market model or not. This initiative seeks to enforce the physical flow limit so that the ISO's market solutions and prices at the interties will reflect this reality. It would not be practical to address the physical flow constraints by adjusting intertie scheduling limits because many of these constraints can be addressed by dispatching internal ISO generation without restricting intertie schedules.

Position 5: Several stakeholders have requested a revision to the current cost allocation methodology for real-time congestion imbalance offset uplift based on cost causation principles.

Response: One of the root causes of real-time congestion imbalance uplift is the lack of unscheduled flow modeling in the day-ahead market. The ISO believes it is important to see the impact of this initiative on such costs and use the data collected from this effort, at a minimum, to inform any future change to the cost allocation of this uplift charge.

Position 6: A few stakeholders are concerned that including flows from external balancing authority areas will render *currently* held congestion revenue rights infeasible.

Response: The ISO expects previously released congestion revenue rights to remain feasible because the ISO conservatively released these only up to 75 percent of the system transmission capacity. If, despite this, they turn out to be infeasible there are procedures in the tariff to address the infeasibility.

CONCLUSION

Management respectfully requests Board approval of the full network model expansion as described in this memorandum. The modeling improvements will enhance reliability and market efficiency by decreasing infeasible schedules in the day-ahead market, increase awareness of outages and other changed conditions throughout the western interconnection, and decrease congestion uplift costs. The separate treatment for the California Oregon intertie allows the ISO to take advantage of west-wide unscheduled flow mitigation procedures and adheres to multi-party operating agreements. Finally, the improved modeling will allow for more accurate power flow solutions for the energy imbalance market.

Attachment G – Key Dates in Stakeholder Process

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

List of Key Dates in the Stakeholder Process

Date	Event/Due Date
June 12, 2013	ISO issues paper entitled “Full Network Model Expansion – Straw Proposal”
June 18, 2013	ISO hosts stakeholder conference call that includes discussion of paper issued on June 12 and presentation entitled “Full Network Model Expansion – Straw Proposal Discussion”
June 25, 2013	Due date for written stakeholder comments on paper issued on June 12
September 11, 2013	ISO issues paper entitled “Full Network Model Expansion – Revised Straw Proposal”
September 18, 2013	ISO hosts stakeholder meeting that includes discussion of paper issued on September 11 and presentation entitled “Full Network Model Expansion – Revised Straw Proposal Discussion”
September 25, 2013	Due date for written stakeholder comments on paper issued on September 11
October 31, 2013	ISO issues paper entitled “Full Network Model Expansion – Second Revised Straw Proposal”
November 4, 2013	ISO hosts stakeholder conference call that includes discussion of paper issued on October 31 and presentation entitled “Full Network Model Expansion – Second Revised Straw Proposal Discussion”
November 13, 2013	Due date for written stakeholder comments on paper issued on October 31
December 5, 2013	ISO issues paper entitled “Full Network Model Expansion – Third Revised Straw Proposal”
December 10, 2013	ISO hosts stakeholder conference call that includes discussion of paper issued on December 5 and presentation entitled “Full Network Model Expansion – Third Revised Straw Proposal Discussion”
December 19, 2013	Due date for written stakeholder comments on paper issued on December 5
December 30, 2013	ISO issues paper entitled “Full Network Model Expansion – Draft Final Proposal”
January 7, 2014	ISO hosts stakeholder conference call that includes discussion of paper issued on December 30 and presentation entitled “Full Network Model Expansion – Draft Final Proposal Discussion”
January 14, 2014	Due date for written stakeholder comments on paper issued on December 30
January 23, 2014	ISO issues paper entitled “Full Network Model Expansion Draft Final Proposal Addendum: Pre-Implementation

Date	Event/Due Date
	Analysis”
January 30, 2014	ISO hosts stakeholder conference call that includes discussion of paper issued on January 23
March 17, 2014	ISO issues draft tariff language regarding modeling enhancements
March 27, 2014	Due date for written stakeholder comments on draft tariff language issued on March 27
April 2, 2014	ISO hosts stakeholder conference call that includes discussion of draft tariff language issued on March 17
May 8, 2014	ISO issues stakeholder comment matrix on draft tariff language
May 16, 2014	ISO issues revised draft tariff language regarding modeling enhancements

Attachment H – Table of Proposed Tariff Revisions

Full Network Model Expansion

California Independent System Operator Corporation

May 22, 2014

<u>Table of Proposed Tariff Revisions</u>

Tariff Section	Description of Tariff Revisions
6.5.10.1.4	Revise section to reflect that the transmission constraint limit report will include information on the fifteen minute market
6.5.10.1.5	Add new section to state that the ISO will provide parties that have signed a non-disclosure agreement with protected data regarding unscheduled flow estimates for each intertie after the results of the day-ahead market and the real-time market are posted
11.2	Clarify section to state that day-ahead market transactions will be settled based on the applicable price for the relevant location for the specific resource or transaction identified as part of the bid
27.1.2.2	Revise section to reflect implementation of real-time market design enhancements
27.4	Revise section to reflect implementation of real-time market design enhancements and make minor clarifying changes
27.4.3	Revise section to make minor clarifying changes regarding applicability of section to enforced internal and intertie transmission constraints
27.4.3.1	Revise section to make minor clarifying changes regarding applicability of section to enforced internal and intertie transmission constraints
27.4.3.5	Revise section to make minor clarifying change regarding applicability of section to internal and intertie transmission constraints
27.5.1.1	Revise section to state that, in the base market model, external balancing authority areas and external transmission systems are modeled to the extent necessary to improve the accuracy of the ISO market solutions for purposes of reliable operations, in addition to the existing stated purpose of supporting the commercial requirements of the ISO markets Revise section to state that the ISO markets optimizations also factor in forecasted unscheduled flow at the interties consistent with the requirements specified in the business practice manuals Revise section to state that, in formulating the market models for the ISO market processes (except for specific intertie locations as specified in the business practice manual), power flow parameters developed from

Tariff Section	Description of Tariff Revisions
	applicable data sources, including available outages information, system status data, and the state estimator for the real-time dispatch, are applied to the base market model Revise section to make minor clarifying changes, including changes regarding applicability of section to internal and intertie transmission constraints
30.5.2.1	Revise section to state that the ISO will create a transaction ID for bids submitted by system resources
30.5.2.4	Revise section to state that the ISO will create a transaction ID for bids submitted by system resources
30.5.2.6.2	Revise section to delete requirement that ancillary services bid include interchange ID code of the selling entity
30.5.2.6.3	Revise section to delete requirement that ancillary services bid include interchange ID code of the selling entity
31.8	Revise section title
31.8.1	Add new section number Revise section to state that section concerns the scheduling constraint Revise section to reflect implementation of real-time market design enhancements and make minor clarifying changes
31.8.2	Add new section regarding enforcement of physical flow constraint limit in the integrated forward market, including circumstances when the ISO will not enforce the physical flow constraint limit
36.4	Revise section to state that adjustments for possible unscheduled flow at the interties will be taken into consideration in determining the monthly available congestion revenue right capacity that is based on the direct current full network model
Appendix A, definition of “Intertie”	Revise definition to mean a transmission corridor that interconnects the ISO balancing authority area with another balancing authority area
Appendix A, definition of “Scheduling Point”	Revise definition to mean a location in the base market model at which scheduling coordinators may submit intertie bids in the ISO markets
Appendix A,	Add definition of new term for transaction identification

Tariff Section	Description of Tariff Revisions
definition of "Transaction ID"	characters that will be generated when bids are submitted by scheduling coordinators at interties for resources whose characteristics are not registered in the Master File