Full Network Model Expansion

Draft Final Proposal

December 30, 2013

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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 8th 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.

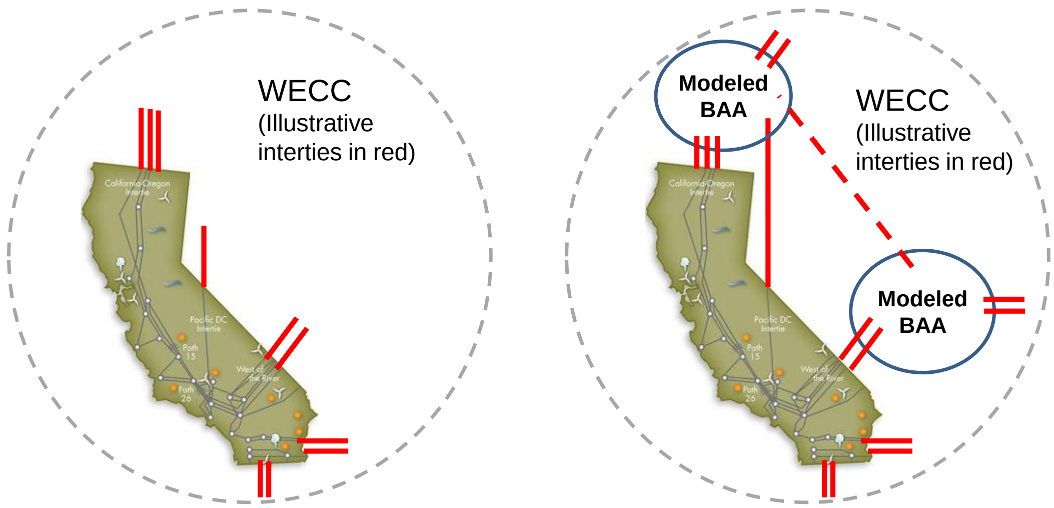
The FNM expansion project is being undertaken to enhance the ISO's modeling of its system. The FNM expansion could be implemented independent of the Energy Imbalance Market (EIM).[8] If the ISO did not create an EIM, it would still pursue this initiative. Also, the policy decisions under each initiative 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.

[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.

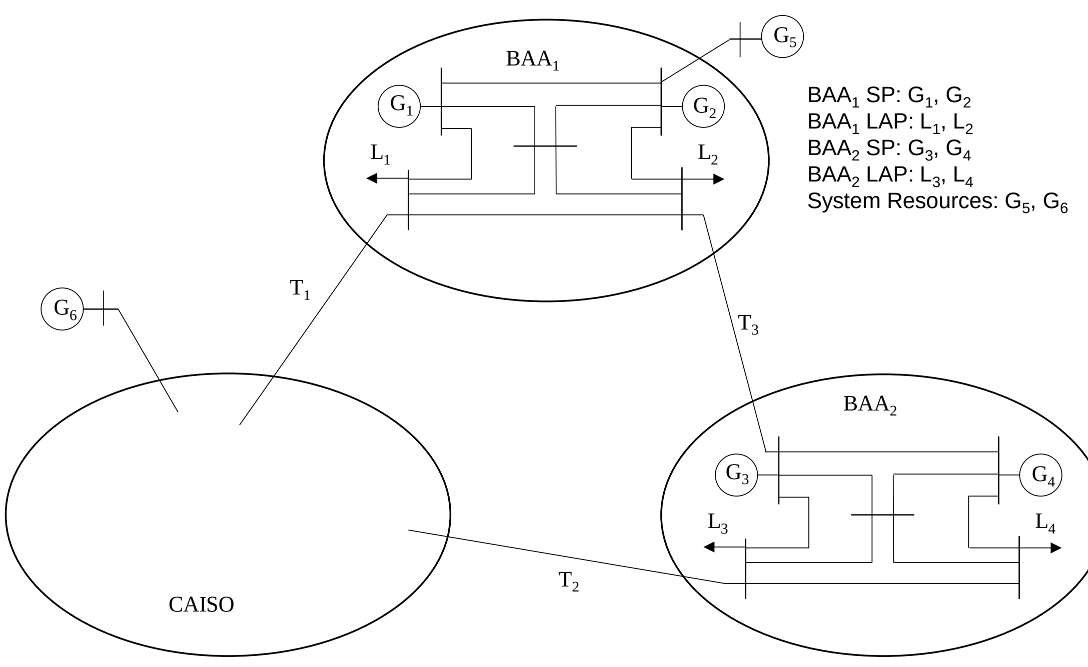
[12] If the FNM encompasses the entire WECC, there would be no need for these boundary points or the associated generic system resources.

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

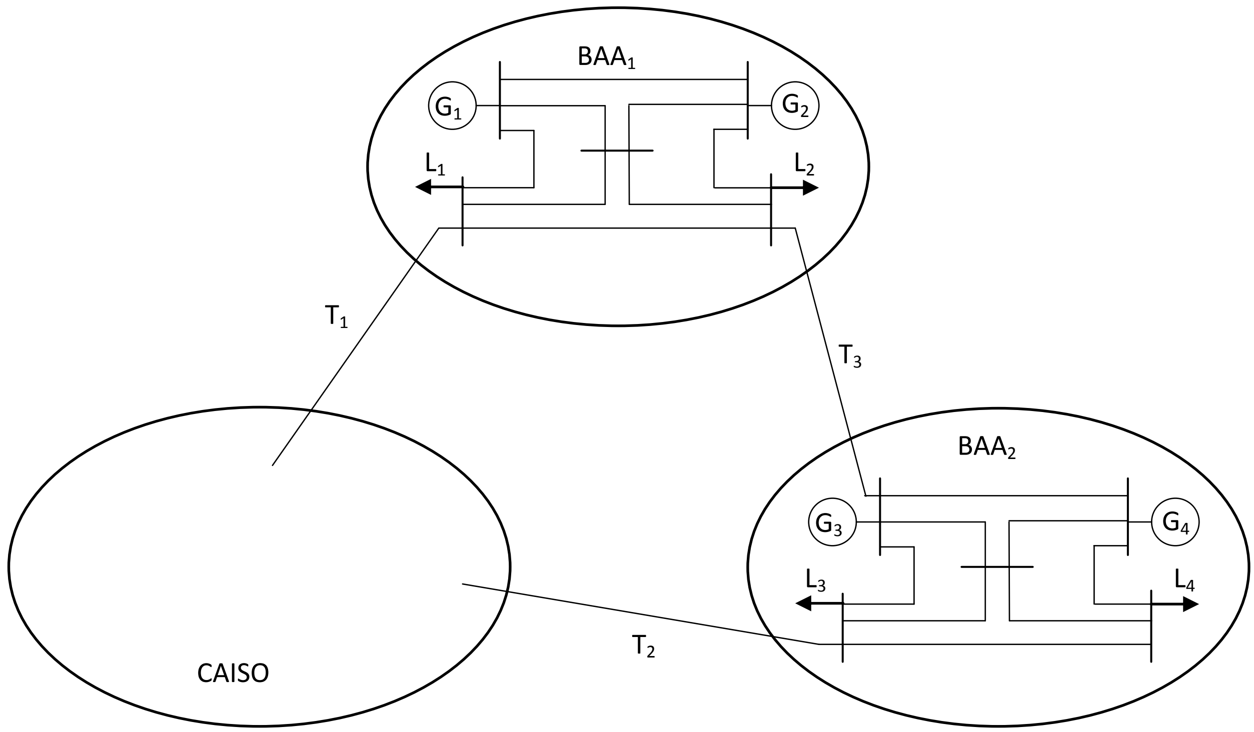


Table 7 shows the calculation of the base generation and load for the two external BAAs. A demand forecast of 1,000 MW is assumed for both BAAs; furthermore, a base net interchange of 100 MW is assumed from BAA_1 to BAA_2. Column [B] lists the total generation and load for each BAA; the total generation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

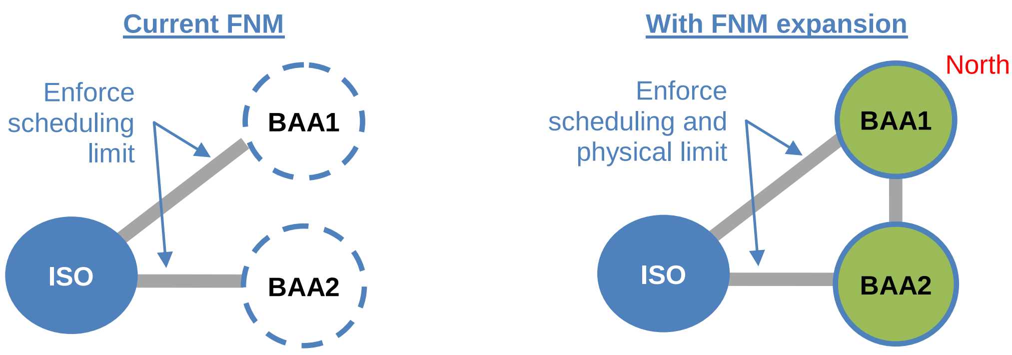
10.2 Example 2: enforcing scheduling and physical constraints on interties

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

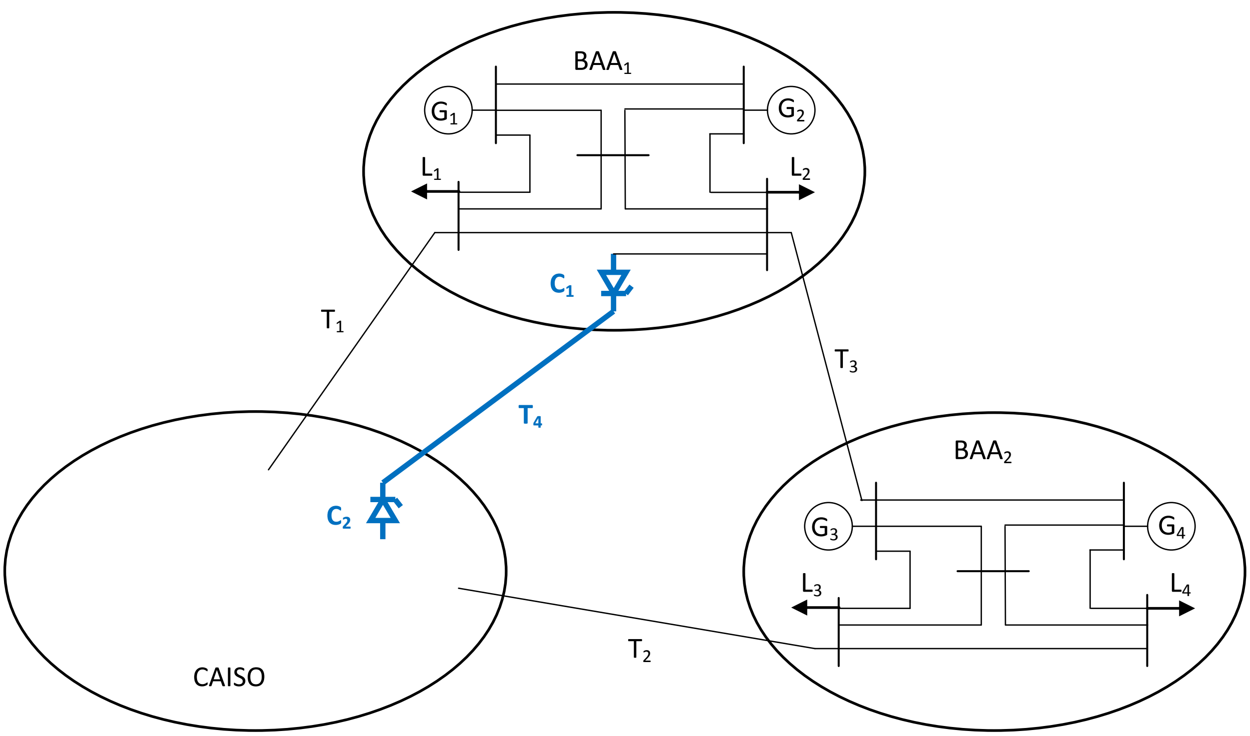
Where: F_1 and F_2 are the base power flows on T_1 and T_2, respectively. These constraints include the power flow contributions from all energy bids, physical and virtual alike, submitted at scheduling points, and internal resources (represented by the ellipsis in the equations above). The formula includes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

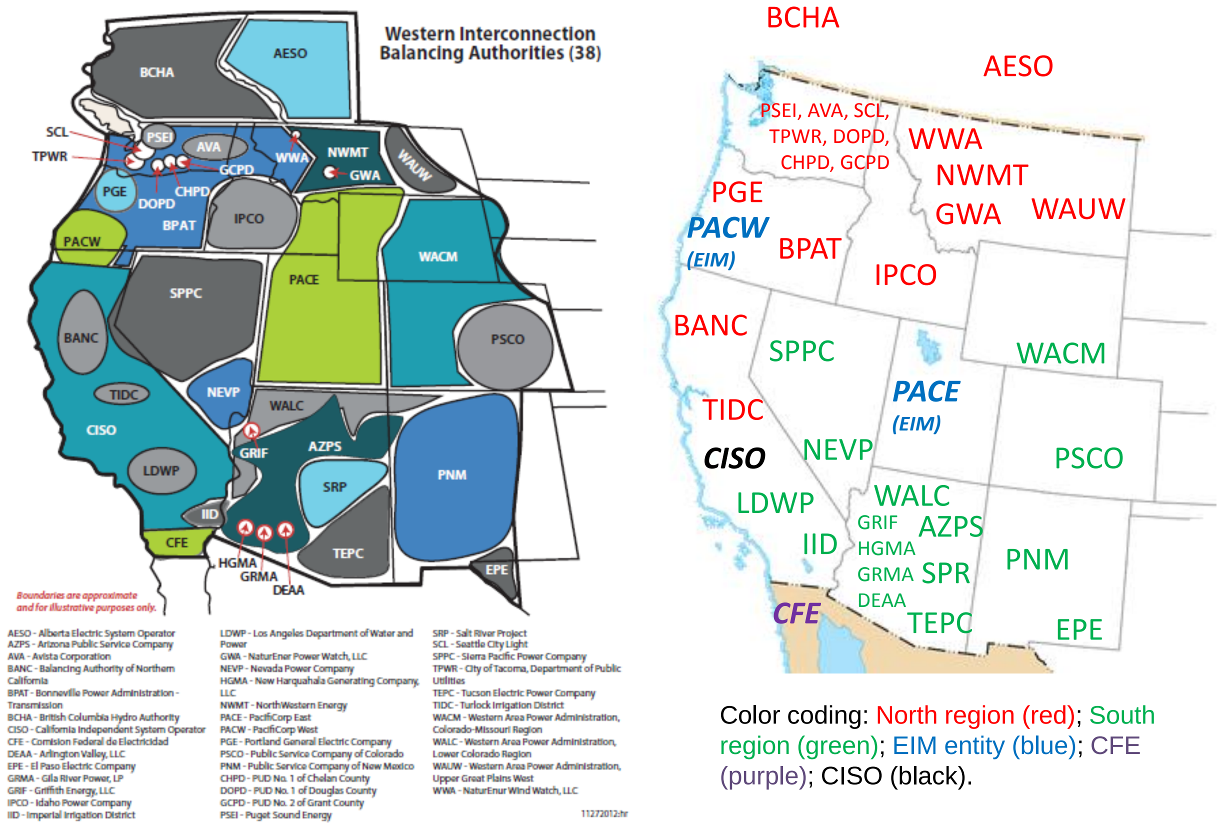
13.2.2 North and South scheduling hub definitions

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

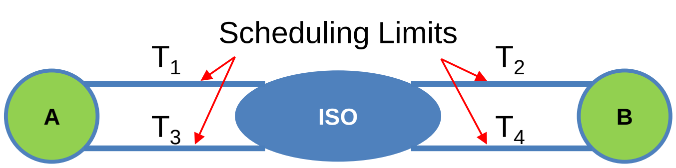
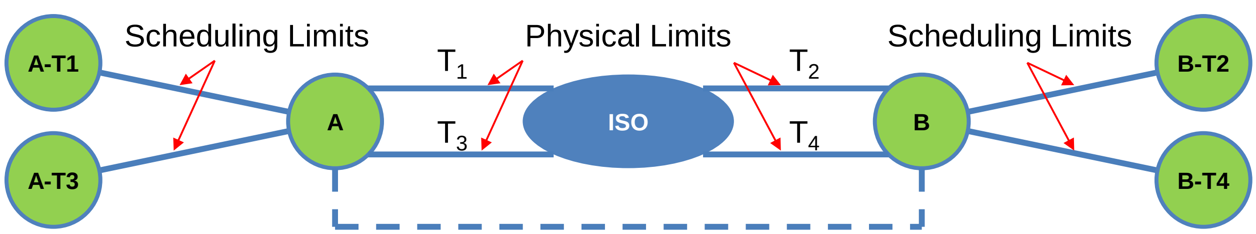


Figure 8 is an illustrative example of the new scheduling hubs under the FNM expansion. To facilitate bidding, scheduling, settlement, and CRRs, multiple scheduling points will be defined for each of these new scheduling hubs, one for each ISO intertie[39] associated with the respective scheduling hub 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

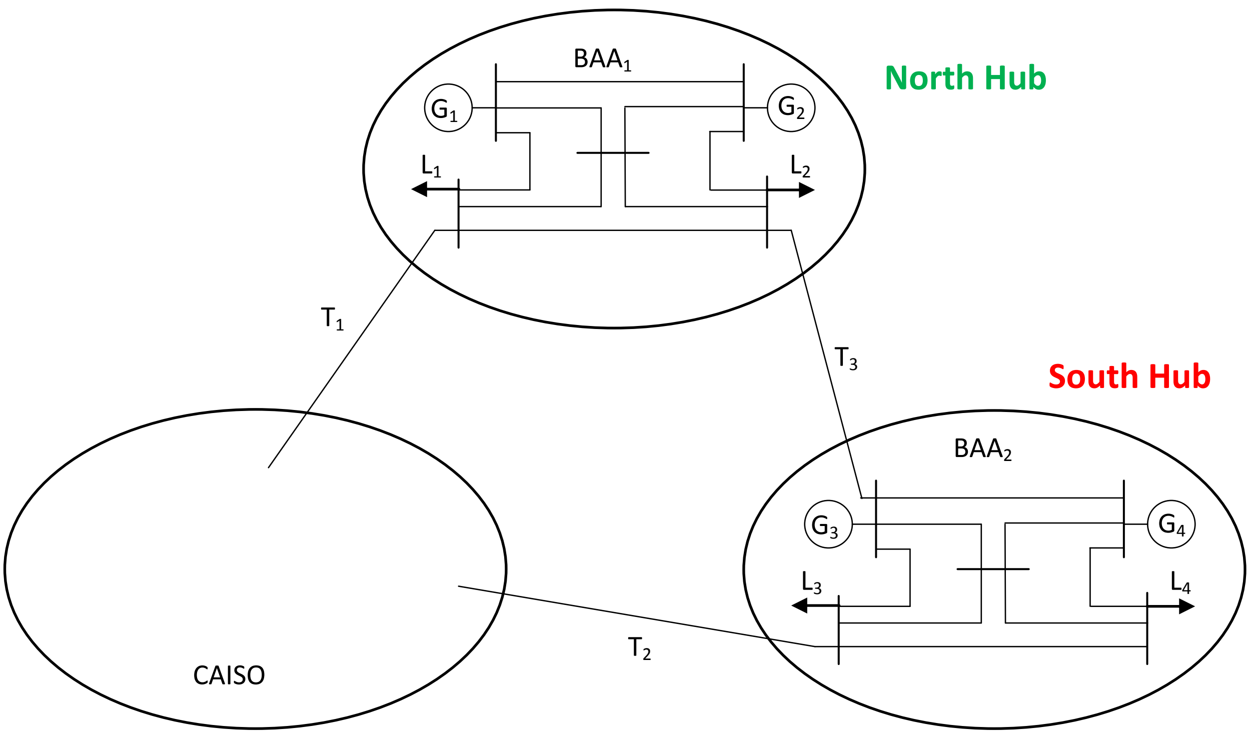


Table 7 shows the calculation of the base generation and load for the two external BAAs. A demand forecast of 1,000 MW is assumed for both BAAs; furthermore, a base net interchange of 100 MW is assumed from BAA_1 to BAA_2. Column [B] lists the total generation and load for each BAA; the total generation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

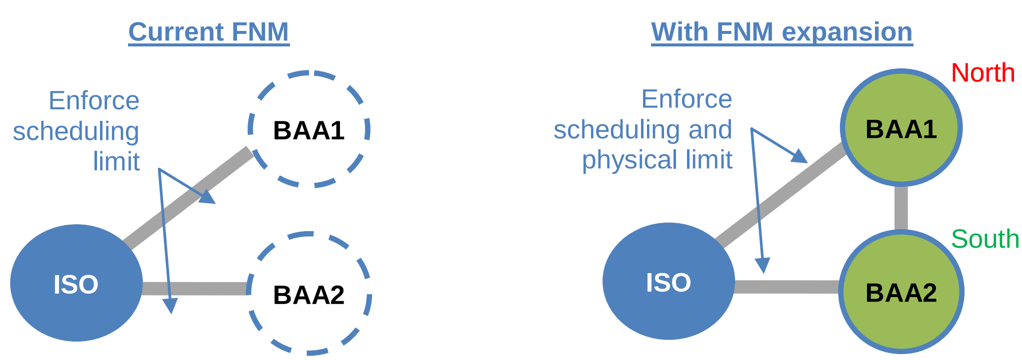
13.5 Example 2: enforcing scheduling and physical constraints on interties

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.

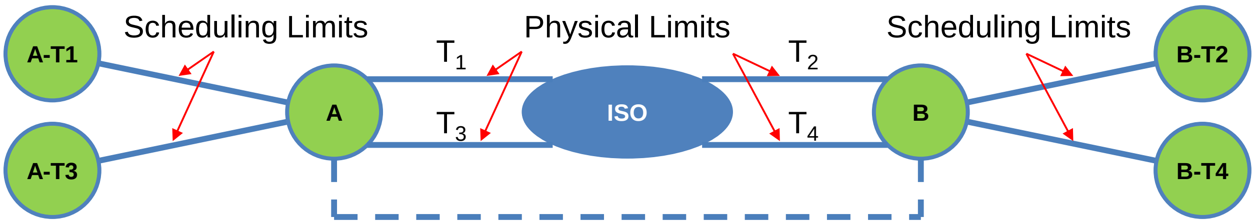
Table 25
LMPs with intertie congestion

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.

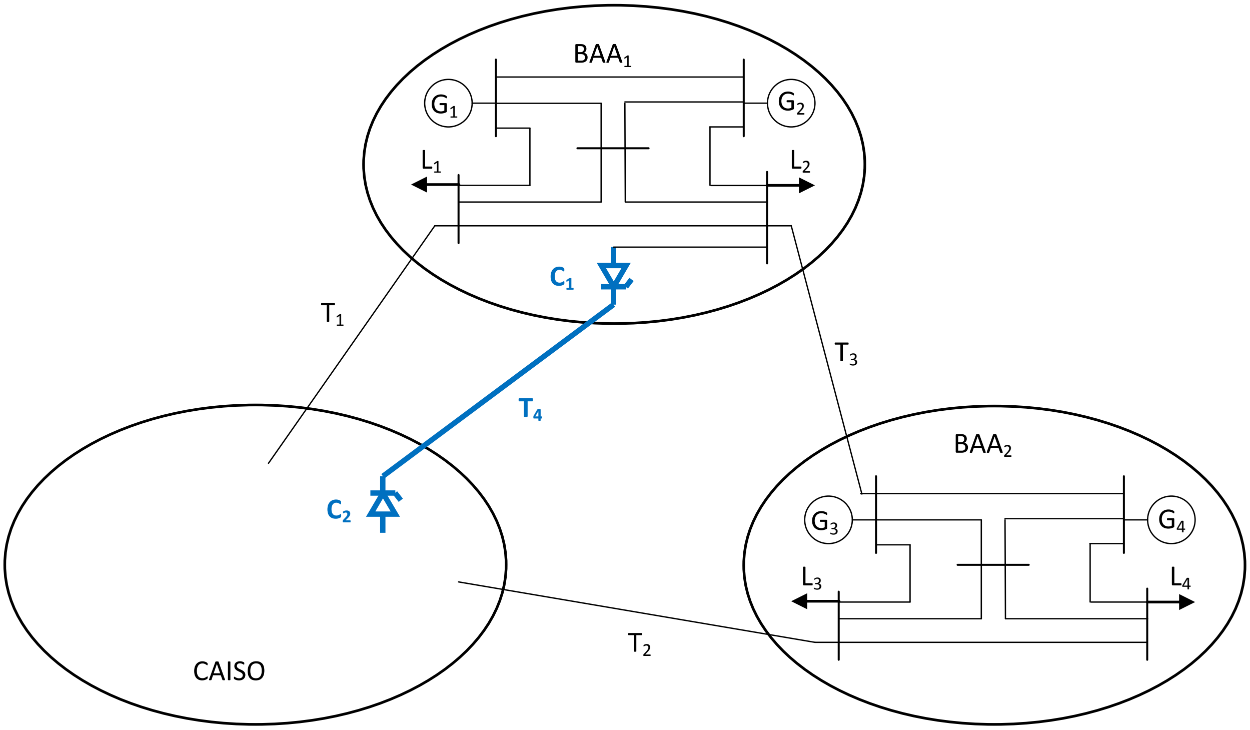
Figure 11
CRRs at new aggregate scheduling points under FNM expansion



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

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

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

Physical limits:

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

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

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		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
	AESO	ALBERTA	87	75	87	75	86	75	87	77	88	77	88	77	88	77	87	76	86	74	87	75	88	77	88	77
	AVA	AVA	86	75	86	75	86	74	87	77	87	77	87	76	87	76	87	75	87	75	87	75	87	77	87	77
	AVA	COLSTRIP	81	69	81	70	81	69	82	72	82	72	82	72	82	72	82	70	82	70	82	70	82	72	83	72
	AVA	MIDC	87	76	87	76	87	75	88	77	88	78	88	78	88	78	88	76	88	76	88	76	88	78	88	78
	AZPS	AZEAST	21	9	21	9	21	10	20	9	19	9	20	9	20	9	22	10	21	10	22	10	20	10	20	10
	AZPS	AZSOUTH	20	8	20	8	20	8	19	8	18	8	19	8	19	8	20	9	20	9	21	9	19	8	19	8
A	AZPS	AZSOWEST	15	4	15	0	15	0	14	3	14	0	14	0	14	3	16	0	16	0	16	0	14	0	14	0
E	AZPS	FCNAREA	24	13	24	13	25	14	23	13	23	12	23	13	23	13	25	13	25	13	25	13	23	13	23	13
R	AZPS	FCNUNIT5	23	11	23	11	23	12	21	11	21	11	21	11	21	11	23	12	23	11	23	11	21	11	22	11
A	AZPS	PHOENIX	18	6	18	6	18	6	17	6	16	6	16	6	17	6	19	7	19	7	19	7	17	7	17	6
	AZPS	PVAREA	17	5	17	0	17	0	15	5	15	0	15	0	15	5	18	6	17	6	18	6	16	6	16	0
G	BANC	SMUD	-1	-13	0	-12	0	-12	-1	-11	0	-11	0	-11	-1	-11	0	-12	0	-12	0	-12	0	-11	0	-11
N	BCTC	BC HYDRO	87	75	87	75	87	75	88	77	88	77	88	77	88	77	87	76	87	76	87	75	88	77	88	77
I	BPA	ASHE	88	76	87	76	87	76	88	78	88	78	88	78	88	78	88	76	88	76	88	76	88	78	89	78
D	BPA	BPA	87	76	87	76	87	76	88	78	88	78	88	78	88	77	88	76	88	76	88	76	88	78	89	78
N	CFE	CFE	14	3	14	0	14	0	13	2	13	0	13	0	13	2	15	0	15	0	15	0	13	0	14	0
E	CISO	ISON	0	-11	0	-11	0	-11	0	-10	0	-10	0	-10	0	-10	0	-11	0	-11	0	-11	0	-10	0	-10
S	CISO	ISOS	11	0	11	0	11	0	10	0	10	0	10	0	10	0	11	0	11	0	11	0	10	0	10	0
	DOPD	DOPD	87	75	87	76	87	75	88	77	88	78	88	78	88	77	88	76	88	76	87	76	88	77	88	78
	EPE	EPE	22	10	22	11	22	11	21	10	20	10	21	10	21	10	23	11	22	11	23	11	21	11	21	11
	EPE	EPEDC	25	13	25	13	25	14	24	13	23	13	23	13	23	13	25	14	25	13	25	13	24	13	24	13
	IID	IID	14	3	14	0	14	0	13	2	13	0	12	0	13	2	14	0	14	0	15	0	13	0	13	0
	IPCO	BRIDGER	66	54	66	54	65	54	69	58	69	59	69	59	70	60	67	55	66	55	66	54	69	58	70	59
	IPCO	IPC	78	66	78	66	77	66	80	69	81	70	81	70	80	70	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.

BAA1 LMP = (SMEC) + ($SF_{BAA1,t1}$ * µ1p + $SF_{BAA1,t2}$ * µ2p) + (0)

BAA2 LMP = (SMEC) + ($SF_{BAA2,t1}$ * µ1p + $SF_{BAA2,t2}$ * µ2p) + (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.

$$\text{North Hub} = [\text{SMEC} + SF_{BAA1,t1} * \mu 1p + SF_{BAA1,t2} * \mu 2p] * 20\% + [\text{SMEC} + SF_{BAA2,t1} * \mu 1p + SF_{BAA2,t2} * \mu 2p] * 80\%$$

Which is the same as:

$$\text{North Hub} = \text{SMEC} + SF_{Nhub,t1} * \mu 1p + SF_{Nhub,t2} * \mu 2p$$

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.

$$\text{North Hub}_{T1price} = \text{SMEC} + SF_{Nhub,t1} * \mu 1p + SF_{Nhub,t2} * \mu 2p + \mu 1s$$

$$\text{North Hub}_{T2price} = \text{SMEC} + SF_{Nhub,t1} * \mu 1p + SF_{Nhub,t2} * \mu 2p + \mu 2s$$

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.