Attachment A

Stakeholder Process: Full Network Model Expansion

Summary of Submitted Comments

Stakeholders submitted five rounds of written comments to the ISO on the following dates:

- Round One, 6/25/13
- Round Two, 9/25/13
- Round Three, 11/13/13
- Round Four, 12/19/13
- Round Five, 1/14/14

Stakeholder comments were received from: Bay Area Municipal Transmission Group, Bonneville Power Administration, Brookfield Energy Marketing LP, California Department of Water Resources, California Public Utilities Commission, Department of Market Monitoring, Morgan Stanley Capital Group Inc., NRG Energy, Pacific Gas & Electric Company, Powerex Corp., San Diego Gas and Electric, Silicon Valley Power, Six Cities, Shell Energy, Southern California Edison, Transmission Agency of Northern California, Western Area Power Administration Sierra Nevada Region, and Western Power Trading Forum.

Stakeholder comments are posted at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/FullNetworkModelExpansion.aspx

Other stakeholder efforts include:

- Stakeholder presentation at Market Performance and Planning Forum, 4/10/13
- Stakeholder call, 6/18/13
- Stakeholder in-person meeting, 9/18/13
- Stakeholder call, 11/4/13
- Stakeholder call, 12/10/13
- Stakeholder call, 1/7/14
- Stakeholder call, 1/30/14
- Numerous outreach calls

	Management proposal: Improve reliability and market efficiency by incorporating external balancing area load, generation, and interchange schedules into the ISO's market optimization		
Stakeholder	**Objective to improve reliability and market efficiency by expanding the full network model**	**Developing external schedules**	**Management response**
BAMx	Support	Including flows resulting from external schedules does not seem to leverage WECC's unscheduled flow mitigation procedure	WECC's unscheduled flow mitigation procedure applies only to "qualified paths" such as the California Oregon Intertie. The ISO will have a separate treatment for the California Oregon Intertie that allows for the use of the procedure. The ISO is uniquely positioned as the only organized market in the Western U.S. and must take measures to ensure that its modeling creates feasible schedules that support reliable operation of the grid and efficient operation of the ISO market. The ISO is active in and complies with regional coordination but should not delay modeling improvements for its own market. The external schedule sources are external for forecasted demand and net scheduled interchange but the ISO will be able to validate, correct, or otherwise modify data based on ISO analyses. In the most extreme scenario, the base schedules can be dramatically reduced to remove or limit the impact of these schedules on the optimization. The ISO plans to calibrate its estimation of the base schedules prior to implementing the full network model expansion functionality and
Bonneville Power Administration	Support	Should establish criteria to show when external schedules are accurate enough and should not implement until criteria is met	
Brookfield	Support	No comment	
CDWR	Support	No comment	
CPUC	Support	No analysis to support this change is cost-effective	
Morgan Stanley	Support	Oppose – increase data exchange with other balancing authority areas or expand use of transmission reliability margin from real-time to day-ahead	
PG&E	Support	Need to retain modeling flexibility Implement in a phased approach with a "safety valve" to stop changes Need to coordinate with other balancing authority areas to diffuse "first mover" risks	
Powerex	Support	No analysis to show data and modeling will be accurate Need to coordinate with other balancing authority areas for data exchange and agreement on coordinated scheduling limits or proposal will undermine regional coordination and Western Interconnection practices	
SDGE	Support	No comment	

	Management proposal: Improve reliability and market efficiency by incorporating external balancing area load, generation, and interchange schedules into the ISO's market optimization		
Stakeholder	**Objective to improve reliability and market efficiency by expanding the full network model**	**Developing external schedules**	**Management response**
SCE	Support	No analysis to show data and modeling will be accurate No cost-benefit analysis to show potential decrease in real-time congestion costs outweigh potential increase in day-ahead market prices	has already begun activities to support this. In addition, the ISO plans to conduct a pre-implementation analysis showing that it 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 to compare the modeled and actual unscheduled flow. A document describing the ISO's approach was provided to stakeholders. Since the analysis requires the software code, the ISO expects to conduct the analysis around the same time as the market simulation timeframe in summer 2014. Modeling base schedules does not affect transmission ownership rights.
Six Cities	Support	No comment	
Western SNR	No comment	Request clarification that base schedules does not affect transmission ownership rights	
WPTF	Support	Should use recent data saved from the ISO's systems to predict which generators are running or not	

	Management proposal: Model topology and base schedules for September 8th entities and balancing areas to support the energy imbalance market		
Stakeholder	**Selection of balancing authority areas to model**	**Implement full network model expansion with energy imbalance market**	**Management response**
BAMx	Need to model integrated balancing authority areas as a priority to be consistent with filings from 2008. A market efficiency enhancement agreement is not sufficient because it only covers SMUD.	No comment	Though the impetus to expand the full network model did not come from the energy imbalance market implementation, it has become clear to the ISO over the last several months that accurate modeling of the energy imbalance market 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 energy imbalance market entity base schedules submitted in the day-ahead timeframe. Delaying the full network model expansion may also delay energy imbalance market implementation. To the extent the ISO has the time and resources, the ISO would like to model the integrated balancing authority area. However, the current modeling of these systems today is sufficient for our needs.
CPUC	No comment	Oppose - separate implementation	
PG&E	No comment	Oppose - separate implementation	
SVP	Need to model integrated balancing authority areas as a priority to be consistent with filings from 2008. A market efficiency enhancement agreement is not sufficient because it only covers SMUD.	No comment	
TANC	No comment	No comment	
Western SNR	No comment	No comment	

	Management proposal: Separate treatment of California Oregon Intertie		
Stakeholder	**Use WECC's unscheduled flow mitigation procedure in real-time**	**Do not enforce physical flow limits on the California Oregon Intertie using the proxy flow limit**	**Management response**
PG&E	Support	Oppose this change because this may be counter to today's practice and enforcement of today's nomograms	The separate treatment for the California Oregon Intertie is in fact continuing today's practice (such as enforcing the current nomograms) and will allow the ISO to leverage the Western Electric Coordinating Council's unscheduled flow mitigation procedure in real-time. Moreover, this will be in accordance with the California Oregon Intertie Path Operating Agreement.
Powerex	Support	Support	
TANC	Support	Per terms of the California Oregon Intertie Path Operating Agreement, concerned that unscheduled flow should not be deducted from the operational transfer capability before real-time and requests clarification from ISO	

Stakeholder	Management proposal: Enforce both scheduling and physical flow constraints	Management response
Powerex	Oppose – enforcing physical flow limits is incompatible with the Federal Energy Regulatory Commission's open access transmission tariff framework in the Western Interconnection. ISO should coordinate with other balancing areas on negotiating the scheduling limits of the interties instead so that there is no disruption to current practices. This approach will also change the prices at the interties and will decrease imports at the interties.	The physical flow limit is already enforced in the real-time over the interties and is enforced both day-ahead and real-time within the ISO. The proposal extends this practice to the interties in the day-ahead so that the day-ahead model better reflects real-time conditions. Physical flow constraints exist regardless if they are in the market model or not. This initiative seeks to enforce the physical flow limit so that the ISO's market solutions and prices at the interties will reflect this reality. It would not be practical to address the physical flow constraints by adjusting intertie scheduling limits because many of these constraints can be addressed by dispatching internal ISO generation without restricting intertie schedules.
Six Cities	Support – proposal aligns physical and virtual prices	

	Management proposal: Bench marking and analysis			
Stakeholder	**Track real-time congestion imbalance offset costs**	**Track compensating injection usage**	**Track market flows and actual flow**	**Management response**
CPUC	Need to base cost allocation on cost causation principles and bench mark impact of this initiative and energy imbalance market separately	No comment	No comment	One of the root causes of real-time congestion imbalance uplift is the lack of unscheduled flow modeling in the day-ahead market. The ISO would like to see the impact of this initiative on such costs and use the data collected from this effort, at a minimum, to inform any future change to the cost allocation of this uplift charge.
PG&E	Support – need to base cost allocation on cost causation principles	No comment	No comment	
SCE	Need to base cost allocation on cost causation principles	No comment	No comment	
Six Cities	Need to base cost allocation on cost causation principles and limit costs to load	No comment	No comment	

Stakeholder	Management proposal: Align congestion revenue rights model by including base schedules	Management response
PG&E	Need to show analysis that awarded congestion revenue rights will pass simultaneous feasibility test	We expect the congestion revenue rights to clear the simultaneous feasibility test because the annual process only releases 75% of system capacity. Should they not, the tariff has provisions to allow for limit expansion. The southwest portion of the Western Interconnection is already represented as a partially looped network in the ISO model and the ISO has already been considering the impact of that on congestion revenue rights for several years.
Powerex	Ramifications of changes and re-introduction of virtual bidding on congestion revenue rights has not been fully analyzed	