REFERENCE PAPERS

Congestion Management – Describes the Grid West market and operational design from the perspective of congestion management, providing a synopsis that considers how the design elements work together to provide a systematic approach to congestion management.

Auction Pricing – Describes the pros and cons of two auction pricing methods – market clearing price and as-offered-price – and the rationale for selection of the market clearing price for use in Grid West markets.

Grid West Seams Issues – Describes the seams coordination issues that may impact Grid West operations. Two types of seams issues are considered: those that involve operational and procedural considerations and those that affect congestion management at the seams.

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1.0 EXECUTIVE SUMMARY

Current problems with managing transmission congestion are briefly reviewed focusing on the need for a comprehensive regional approach to congestion management. Methods for managing congestion are reviewed and the advantages to the Northwest of using the Grid West flow-based, physical rights model are identified. The Grid West plan for congestion management is evaluated for long-term, short-term and real-time periods, to see how various features inter-relate and address needs for each time period. The TSLG believes it has designed a congestion management approach for Grid West that will be workable, economically stable, cost-effective, and superior to current practices.[1]

2.0 PURPOSE

This reference paper describes the Grid West market and operational design from a congestion management perspective. Unlike the individual white papers that discuss specific design elements in some detail, this paper is a synopsis that looks across all design elements to show how the assembled whole provides a systematic approach to congestion management.

3.0 BACKGROUND

Congestion management refers to a system of mechanisms that control use of the transmission network to prevent exceeding the network's reliability operating limits, while enabling the most efficient and maximum use of the network.

- Today each transmission owner manages congestion within its portion of the network, and a contract path model is used for coordination of usage between transmission owners.
- Under the contract path model, transmission owners grant usage rights for only the facilities they own as if the effects of usage were limited to that owner's facilities. However, once transmission lines are interconnected to form a network, power flow over the interconnected network is governed by system physics without regard to ownership.

[1] Given the differently situated regulatory regime in Canada and British Columbia, in particular, the operating assumption is that the Grid West market design will be mirrored in British Columbia, to the extent possible within that regulatory regime. Details regarding the market design in British Columbia are anticipated to be completed as part of detailed design phase of this effort.

- Since each owner's operational view is restricted to its own facilities, rules have been devised to limit each owner's network use in order to mitigate the effect of any one party's use on other parts of the network.
- While this situation permits autonomous operation by owners, these limitations impose a cost in the form of underutilized transmission capacity, i.e., capacity that could be made available if the network was managed as a single system.
- Reliability suffers today when problems appear with little warning. Each operator sees only its part of the system, and there is not a single system view in advance of real time operations to help foresee problems and guide response. Also, reliability curtailments are sometimes ineffective because they lead to no actual change in generation dispatch; energy is simply rescheduled through systems that are unaware of the problem. At other times, curtailments can be greater than really required, which leaves capacity unused that would be available had the adjustments been directed centrally.
- The Grid West proposal will implement a flow-based approach to congestion management that will enable increased usage of transmission capacity based on a system-wide view of the collective capacity of the combined systems.

This paper shows how Grid West's flow-based approach to congestion management is woven into the fabric of its market and operational design.

- In Section 4.0, congestion management models are examined. First, consideration is given to the impact that open access requirements have had on the need to formalize congestion management. Next the Grid West physical rights approach to congestion management is described in general terms. The alternative financial rights approach is also described to clarify the differences between the Grid West physical rights proposal and the financial rights approach used in many ISOs and RTOs. Finally the advantages of the Grid West approach are described for meeting the transmission needs of the Northwest.
- In Section 5.0, the Grid West congestion management approach is evaluated in more detail by considering how the design functions in various time periods: for long-term service (greater than one year), for short-term service (less than one year) and for real-time service (within an operating hour).
- Section 6.0 draws conclusions regarding the suitability and workability of the proposed Grid West approach to meeting Northwest congestion management needs.

4.0 CONGESTION MANAGEMENT MODELS

4.1 Open Access

- In order to provide open access, operators of transmission systems needed a means of determining how much uncommitted capacity was available for use by parties requesting service. This need led to a formalization of congestion management practices in order to provide comparable transmission access.
- In most areas, the initial implementation of open access under Order No. 888 simply extended the traditional physical rights, contract path model.
- However, for tight power pools in the Northeast, Order 888 implementation led to a congestion management approach that uses a pooled generation dispatch with centralized unit commitment and financial transmission rights.
- As RTOs were considered under Order No. 2000, there was an extensive debate over the merits of the pool-dispatch, financial rights approach versus a further extension of the physical rights model.
- The financial rights model was particularly controversial in the Northwest, where resistance to it stalled the RTO West proposal.
- A re-examination of the Northwest transmission challenges in 2003 led to the development of the Grid West flow-based physical rights approach to congestion management.

4.2 Grid West's Physical Rights Congestion Management Model

- Grid West will implement a system-wide flow-based physical rights approach that manages congestion by requiring that any schedule for transferring power through the system must be accompanied by an appropriate transmission right.
- New transmission use rights will be issued by Grid West as Injection-Withdrawal Rights (IWRs), where each right is based on use of the combined capacity of the Grid West Managed Transmission System (GWMT) which connects the point of injection to the point of withdrawal. The analysis supporting issuance of each IWR considers how power flows will be affected on a system wide basis and assures that overloads will not be created when the right is used for power schedules.
- Existing transmission rights are protected and unchanged by the Grid West proposal.
    - This is possible because IWRs are a flow-based extension of the pre-existing physical transmission rights issued today.
    - It will not be necessary to convert pre-existing transmission rights into another form.

  - Grid West will inventory the existing obligations, reserving capacity needed to cover the injection and withdrawal impacts in the GWMT.
- The issuance of IWRs manages congestion ahead of time (or ex-ante); dealing with the congestion potential of an IWR at the time the right is issued. The cost of acquiring IWRs will be (in the short run) the de-facto forward congestion charge.

4.3 Financial Rights Congestion Model

In order to better understand the Grid West physical rights proposal, it is useful to consider the chief attributes of financial rights approach to congestion management that is used in many ISOs and RTOs.

- In a financial rights model, explicit congestion charges are applied to all transmission use.
- Unlike a physical rights approach, congestion is addressed after schedules are submitted, using centralized redispatch of generating resources in a day-ahead energy market to correct line overloads.
- Because congestion management is after the fact (or ex-post) under this approach, the user finds out at settlement what its congestion charges are.
- Transmission rights are not required to schedule, instead they serve as financial hedges against congestion cost exposure.
  - The RTO operating under financial rights has an obligation to assure delivery of all scheduled power, although it may charge the cost of clearing congestion necessary to make the delivery.
  - The holders of financial transmission rights receive a stream of revenue that is based on distributing the congestion charge collections among the holders of financial transmission rights.
  - The ability to adjust financial transmission right holdings occurs only at monthly (or longer) intervals.
- One of the key objections to the RTO West proposal was the need to convert existing transmission rights and obligations into a form of financial transmission rights. The conversion process was complicated by both the changed character of the rights and by a potential ongoing obligation for transmission owners to provide congestion management assets to honor the rights in their new form.

4.4 The Advantages of the Grid West Model for the Northwest

- Grid West will have a “big picture” view of GWMT usage, including all day-ahead schedules.

  - That knowledge that will permit Grid West to anticipate problems during the day-ahead process when there is more time for a measured response.
  - When corrective action is required, Grid West will be able to coordinate adjustments or curtailments based on the system-wide impact of changes made.
- Pre-existing rights are protected and integrated with the issuance of new physical transmission rights.
  - The contentious debate over right conversion is avoided.
  - While new mechanisms are provided for obtaining transmission rights as IWRs, the use of IWRs is a straight forward extension of existing scheduling practices.
- Transmission cost can be determined in advance.
  - Given its hydro-electric generation base, the Northwest has a long history of bilateral trade in forward energy.
  - Transmission price certainty has been viewed as desirable by market participants for such forward trades.
- Unit commitment remains with generation owners.
  - In the tight power pools of the Northeast and other areas, centralized unit commitment for thermal resources is a desirable feature that is integrated with a day-ahead energy market.
  - Given the generation mix in the GWMT, centralized unit commitment is neither needed nor desired by the region.
    - About two-thirds of the energy supply is from hydro – units that have start times measured in minutes rather than hours.
    - The operation of the collective hydro resource has extensive coordination to deal with the hydrological complexities of combining the fishery, navigation, flood control, recreation and power production obligations.
    - Much of the remaining energy comes from base-load thermal plants that do not start and stop on a daily or weekly basis.
- Since transmission right holders are required to submit any schedule, a lack of transmission capacity should be more likely to trigger investment in transmission expansion than has proven to be the case in financial right implementations.

5.0 A DETAILED DISCUSSION OF GRID WEST'S CONGESTION MANAGEMENT PROCESSES

The Grid West process provides a comprehensive approach to congestion management, with some features being more significant in different time periods than others. This section will look at three time periods (long term, short term and real-time) and evaluate the features of the Grid West design that respond to congestion management problems for that time period.

5.1 Long Term – Planning and Capacity Expansion

- Parties with long-term energy investments (i.e., for one-year or more) will want to have long-term transmission rights.
    - The rights will be needed for financing new projects to prove deliverability under a physical rights scheduling paradigm.
    - Long-term rights are desired by power purchasers and load serving entities (LSE) who wish to have certainty of delivery at a known cost.
- Long-term users see a lack of transmission as potential future congestion.
    - Funding expansion to obtain rights is a forward commitment made to avoid future congestion cost which would take the form of higher payments for short-term rights.
    - The cost of expansion serves as an upper bound on the cost of future congestion.
- Given the need to hold rights to schedule, the Grid West approach may be more likely to trigger expansion than has proven to be the case in financial right implementations.
- Grid West will sell long-term transmission rights both from any capacity that may be available within existing facilities and from construction of new facilities.
- Grid West will do the planning to support purchase of rights via capacity expansion.

5.2 Short Term – Reconfiguration

- The reconfiguration auctions enable trades in transmission rights.
    - Using the power flow mechanics, it enables trade among parties, whose rights for sale are not identical with those who need to purchases rights, i.e., they do not have the same injection and withdrawal points.
    - Auction prices provide a transparent source of information for all users about the value of transmission rights.

  - This transparency both encourages release of transmission rights that might otherwise go unused and provides a reference point for other trades in bilateral markets.
- Prices in the reconfiguration auctions will be based on the offer and bid prices supplied by the transmission customers. As a result, the clearing prices will be the de facto value of avoiding congestion (i.e., having the ability to schedule use) in future periods.
- Both released rights and available flow capacity (AFC) will be simultaneously available to meet transmission customer requests.
  - With Grid West being an independent party, having no gain or loss as a result of auction outcomes, market participants can reveal their true values to Grid West, knowing that they will get the best prices available for their sales and purchases.
  - Grid West will be a price-taker when selling AFC, so that it will assure the lowest appropriate prices are available to transmission buyers.

5.2.1 Annual, Monthly and Intra-monthly Auctions

- The reconfiguring auctions run in annual, monthly and intra-monthly intervals and will provide transmission customers with an opportunity to obtain rights shaped to meet different needs and to make adjustments as their needs change over time.
- Both on- and off-peak rights will be offered to allow prices to follow differences in system loading and energy value between on- and off-peak periods.
- As energy prices change over a year or a month, transmission clearing prices will change, implicitly capturing the perceived value of congestion (i.e., the inability to use preferred resources).

5.2.2 Day Ahead Auction – Added Features

- Some transmission rights have the flexibility to, for example, schedule to a single load from either of two generators. To accommodate this scheduling flexibility, transmission capacity for both alternative sources is withheld from AFC calculation even though only one source may be used at any given time. The Day-ahead reconfiguration service will not only include the IWR offers and AFC, but will also allow parties to be paid for giving up their scheduling flexibility.
  - Releases of scheduling flexibility optionality decreases the “head space” held back to enable post-day ahead scheduling of pre-existing rights increasing AFC.

  - Releases of scheduling flexibility approximate the generation commitments of a day-ahead market, making more transmission available on an economic basis. This is done without creating the settlement complications of a purely voluntary market where some parties retain the ability to change schedules until the cut-off to real time.
- Again, the clearing prices will represent the de facto congestion cost value of holding transmission rights.

5.2.3 Day Ahead to Real Time Adjustment Period

- After the completion of the day-ahead reconfiguration and day-ahead scheduling, uncommitted capacity will be made available by Grid West on a first come, first served basis. This will be roughly equivalent to the short term non-firm transmission available today.
- Because of Grid West's single system point of view, scheduling of this as available capacity will consider the impact on all critical network elements, thereby providing both better access to and better overall management of the available capacity across the combined network.

5.3 Real Time

5.3.1 Monitoring and Operational Activities for GWMT

- Grid West will be the Transmission Authority for the GWMT.
  - Grid West will use metering and state estimation to monitor flows on GWMT facilities, examine the effects of contingencies and maintain system reliability.
  - When potential problems are detected, Grid West will notify operators of balancing areas within the GWMT of the need to take appropriate actions to maintain reliability.

5.3.2 Real-Time Balancing Service for CCA

- Grid West will be the Balancing Authority for the Consolidated Control Area.
- In the operation of the Real-time Balancing Service, Grid West will select resources to respond to changes in load and generation using a security constrained economic dispatch.
  - Resources will be selected to meet balancing needs based on achieving the best overall value within system constraints.
  - The constraints considered include both the operating characteristics of the generators (responsiveness, max and min

limits, etc.) and the reliability operating limits of the transmission system (line ratings, system voltage levels, etc.)
    - Since Grid West is an independent operator, without a financial stake in energy trade, market participants will have the assurance that they can submit offers based on the true value of their resources without prejudicing their commercial position and with confidence that the resulting prices represent the best economic outcome for themselves and others.
- Differences in clearing prices for balancing energy between locations will represent the value of system congestion.
- The reporting of real-time prices, and their history over time, will provide a guide to bidders in reconfiguration auctions as they judge the value of transmission rights for avoiding future congestion.

5.4 Summary

Clearing prices in the reconfiguration auctions represent the buyers' and sellers' views of the value of transmission rights and are thus the value they collectively place on avoiding congestion cost, that is, the ability to use economically preferred resources to serve load. Unlike the financial rights models, where monthly auctions have been deemed sufficient, the intra-monthly and day-ahead auctions are needed in the Grid West model to make as much transmission capacity available as possible prior to scheduling.

In real time, Grid West monitoring of the entire network will allow it to provide guidance to non-CCA balancing area operators. Within the CCA, Grid West will use a security constrained dispatch to manage congestion while selecting the most economic offers to meet real-time balancing needs.

6.0 CONCLUSION

After many years of debate, the region settled in 2003 on key features needed to address transmission problems. First, a flow-based, physical rights approach to congestion management was to be used in preference to a financial rights approach. Second, pre-existing transmission rights were to be protected, with no forced conversion to another form of service. Third, there was a need to make better use of existing transmission capacity and provide a means for effective transmission expansion. Given these characteristics, as described in the Regional Proposal, the challenge for the region and the assignment of TSLG in particular, has been to develop within these constraints a congestion management approach that is physically workable, economically stable and cost-effective. TSLG believes that the Grid West market and operational design will meet these objectives.

- Grid West will be able to offer congestion management services, such as transmission right reconfiguration, that no single entity or affiliated entity could offer, because Grid West will be independent of market participants and have a big picture view of the entire GWMT.
- Moving to the Grid West's flow-based physical rights approach to congestion management will be workable, because it is an extension of existing practices. Transmission customers will be able to use the new products and procedures without major changes in their operational practice.
- In terms of market economics, the effect of Grid West markets and services will be incremental rather than revolutionary. Pre-existing transmission rights will remain in place and serve as the stable base of transmission usage as new services are added.
- TSLG believes that implementation can be cost-effective, because the new services associated with congestion management can be provided with minimal additional metering and using (with modest modifications) software systems that are already available from vendors.

The congestion management features of Grid West are woven into its market and operational design. The basic philosophy for Grid West congestion management is to control the issuance of transmission rights to avoid over committing the transmission system well in advance of operation and to avoid overloaded facilities at the time when scheduling occurs in the day-ahead process. Reconfiguration services are provided to allow transmission customers to adjust their transmission right holdings annually, monthly, within a month and just before day-ahead scheduling. These features will allow Grid West to effectively manage congestion and meet the overall design objectives of the Regional Proposal.

1.0 EXECUTIVE SUMMARY

The objectives of this paper are to provide an overview of both "Market Clearing Price" (MCP) and "As-Offered Price" (AOP) methodologies, to discuss the pros and cons of each approach, and to propose a methodology for auction pricing of Grid West's Injection/Withdrawal Rights (IWR), Reserve, and Real Time (RT) markets.

This paper presents the rationale for selecting the MCP approach. While the paper confirms MCP and AOP converge to similar prices for customers in competitive markets, it also discusses how in less competitive markets, AOP can increase the market power of dominant players, raise the barrier to entry for smaller players, and reduce market efficiency in comparison to MCP. The paper also discusses the use of market monitoring to prevent potential market power abuses with the MCP approach.[1]

2.0 METHODOLOGY OVERVIEW

The best way to highlight the differences between MCP and AOP methodologies is to use an example with a simple energy market. In this example, the market has collected three offers to sell energy and three bids to buy energy. These offers and bids are shown in the tables below.

Table 2.1

Offer to Sell Energy	
Quantity	Price
100 MWh	$10/MWh
100 MWh	$15/MWh
200 MWh	$20/MWh

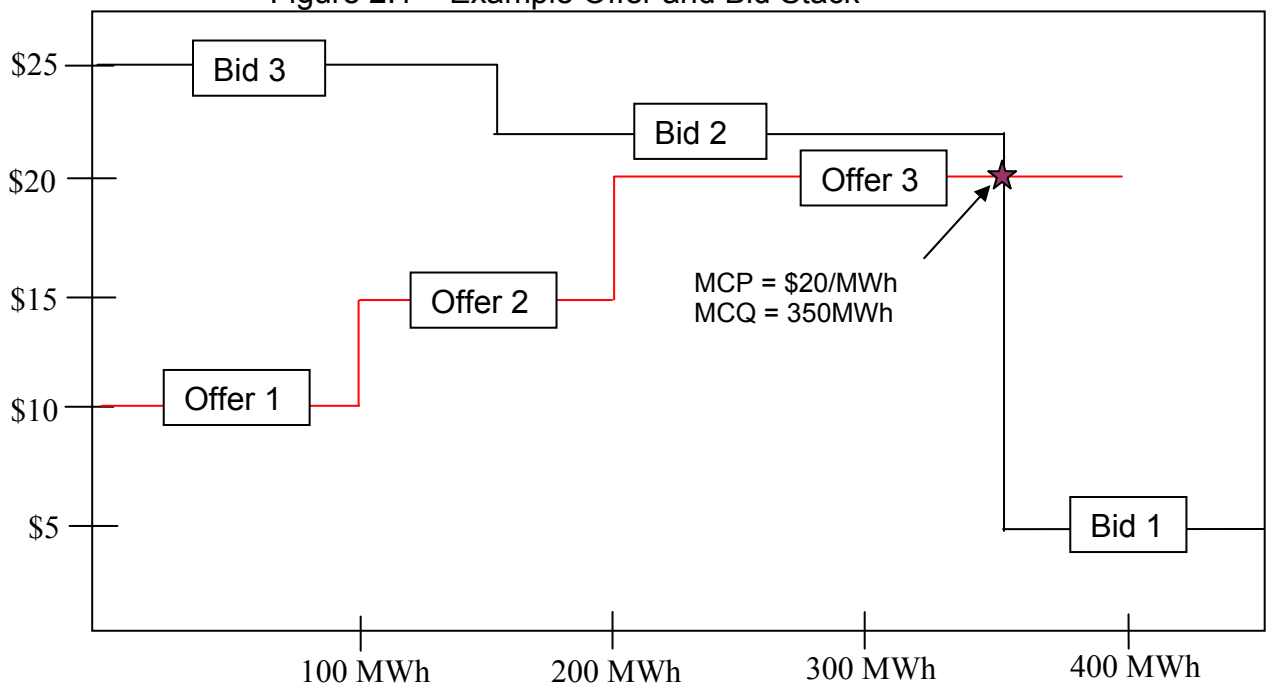
Table 2.2

Bid to Buy Energy	
Quantity	Price
100 MWh	$5/MWh
200 MWh	$22/MWh
150 MWh	$25/MWh

As part of the auction, the offers and bids are stacked as shown below:

[1] Given the differently situated regulatory regime in Canada and British Columbia, in particular, the operating assumption is that the Grid West market design will be mirrored in British Columbia, to the extent possible within that regulatory regime. Details regarding the market design in British Columbia are anticipated to be completed as part of detailed design phase of this effort.

Figure 2.1 – Example Offer and Bid Stack



We assume that the objective of the auction is to maximize overall trade value (market surplus). As a result, the Market Clearing Quantity (MCQ) of 350 MWh and the winning offers and bids are the same for both pricing methods. The only difference is in the awarded prices, as shown below:

Table 2.3

Offer/Bid	MCP pricing		AOP pricing	
	Awarded Qty	Awarded Price	Awarded Qty	Awarded Price
Offer 1	100 MWh	$20	100 MWh	$10
Offer 2	100 MWh	$20	100 MWh	$15
Offer 3	150 MWh	$20	150 MWh	$20
Bid 1	0	N/A	0	N/A
Bid 2	200 MWh	$20	200 MWh	$15.71
Bid 3	150 MWh	$20	150 MWh	$15.71

Under MCP, the awarded offers and the awarded bids will be settled using the same market clearing price. Under AOP, the price applied to the awarded offers differs from the price applied to the awarded bids. The awarded offers receive

their offer price, while the awarded bids pay a calculated price. There are several possibilities for deriving the price that bidders pay, including:

- Clearing price
- Average price
- Bid price
- Forecasted price

In this example, we assume that awarded bids pay a weighted average price of $15.71 to cover the overall payment for awarded offers.

3.0 PROS & CONS OF PRICING METHODOLOGIES

The AOP pricing methodology is similar to the commonly used rate-of-return approach practiced by regulated utilities whereby utilities pay suppliers (generators, whether their own or a third party's) their regulated cost-based rates (which include reasonable profits) and then charge an average fee to energy customers. AOP is also used, albeit less frequently, at a few RTOs/ISOs. Examples include:

- Congestion pricing at the Ontario IMO;
- Intra-zonal congestion management pricing at the California ISO;
- Intra-zonal congestion management pricing at the ERCOT ISO.

The MCP pricing methodology is used by nearly all RTOs, ISOs and Power Exchanges as the primary pricing mechanism for markets. The main reason for its widespread use is that MCP pricing encourages suppliers to offer their actual marginal/opportunity costs.[2] If a supplier's offer is rejected because there are lower-priced offers to satisfy the demand, the supplier will be better off, as it will not have committed itself to sales at prices that fail to cover its marginal/opportunity costs. More importantly, if its offer is accepted, it will receive the benefit of an MCP price that is at least equal to its marginal/opportunity cost and permits it to receive contributions toward its fixed charges and profits. In the example presented above, the infra-marginal Offer 1 will receive $10/MWh and the infra-marginal Offer 2 will receive $5/MWh beyond their offer prices and towards fixed-cost recovery and profit. This assumes the market is competitive, whereby suppliers raising their offer price beyond their

[2] Opportunity cost is the higher of the marginal cost of the energy or the value of alternative uses of that energy - such as selling the energy bilaterally or using the energy output of an energy limited resource for load service or other revenue producing applications at a later time.

marginal cost actually risk not being selected in the auction due to lower-priced alternatives.

Advocates of AOP pricing maintain that, under MCP pricing, infra-marginal offers receive more than their offer price; hence, energy users will pay additional amounts to cover this extra payment to suppliers. They also maintain this will not occur under AOP pricing. In the example above, the average energy price for buyers is $15.71/MWh under AOP versus $20 under MCP pricing. Hence, AOP seems to reduce the average cost of energy-to-energy buyers, *as long as suppliers continue to offer their energy at their marginal/opportunity cost into an AOP-based market*. The critical assumption is that under AOP pricing, suppliers will continue to offer their energy at their marginal cost. *In many cases, this assumption does not hold true*. In order to maximize their profit (or at least receive contribution for their fixed costs), suppliers may increase their offer above marginal/opportunity cost, and offer their energy at what they expect the MCP will be ($20 in the foregoing simple example).[3] In the past, various experiments have shown there is no reason to expect prices will be consistently lower under AOP pricing.[4]

In addition to there being no clear evidence that an AOP pricing methodology lowers prices, AOP can distort the market for the following reasons:

- *AOP can reduce overall market efficiency*: AOP can reduce efficiency as generators are forced to depart from bidding marginal/opportunity costs in an attempt to receive compensation for their fixed costs. This departure may distort the bid stack: some lower marginal-cost (less expensive) resources will be rejected (because their suppliers overestimated the MCP and submitted an offer price with a high markup) in favor of other higher marginal-cost (more expensive) generation offered with more conservative markups. Interestingly enough, the more competitive the market and the larger the number of competing suppliers, the greater the number of instances in which output will be drawn from the higher marginal-cost (more expensive) generators. The consumers eventually bear these costs directly or indirectly.

[3] They will discover the MCP by comparing the results of the previous auctions with their offer prices.

[4] The Treasury conducted an experiment, in which it employed both MCP and AOP pricing mechanisms in the sale of Treasury bills. It found mixed results, and could not conclude that the average winning bid prices of the two mechanisms differed significantly.
["Uniform-Price Auctions: Update of the Treasury Experience." Working Paper, U.S. Treasury, 1998.]
["Some Evidence on Bid Sharing and the Use of Information in the U.S. Treasury's Auction Experiment." Working Paper, Board of Governors of the Federal Reserve System, 1996.]

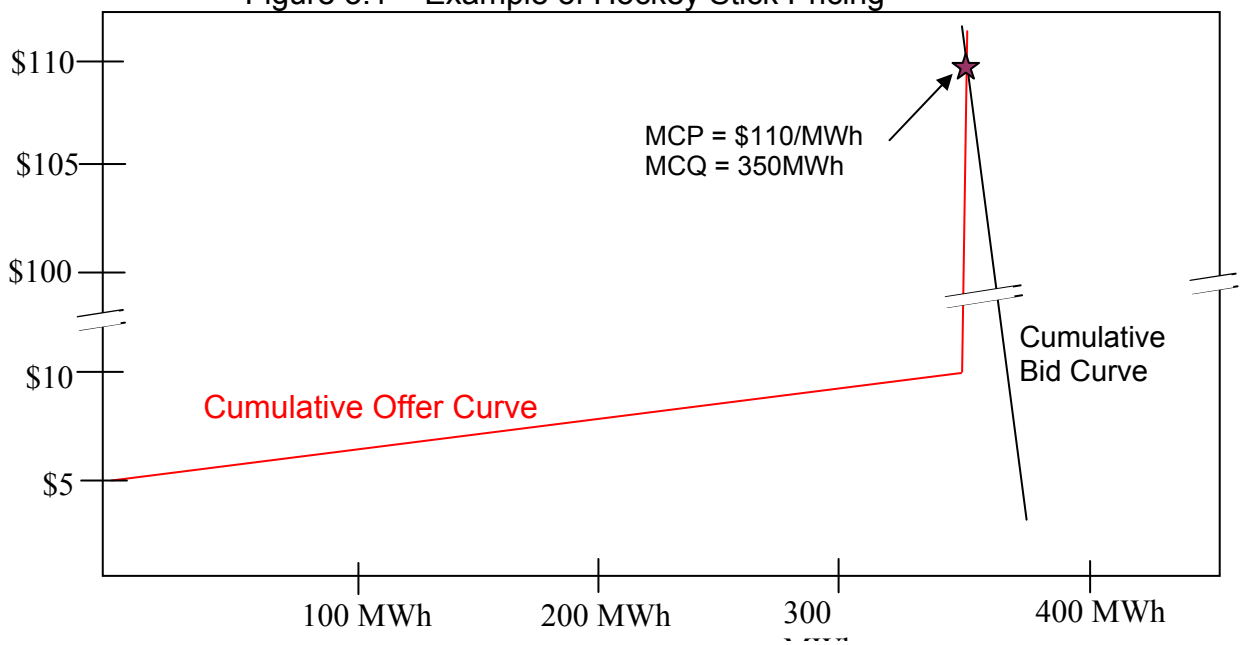
- *AOP can increase cost of participation in the market:* Another inefficiency introduced by AOP pricing is the cost associated with forecasting market prices. Under MCP pricing, sellers offer their supply at marginal/opportunity costs, which are readily available. AOP pricing introduces uncertainties and costs into suppliers' price estimation efforts.
- *AOP can disadvantage smaller players:* Unlike MCP pricing, where competitors succeed or fail based on their generating efficiencies, success under AOP pricing depends heavily on successful price forecasting. There are large costs and economies of scale in price forecasting activities; therefore smaller firms may be at a disadvantage since they have to spread such costs over smaller sales.
- *AOP is more susceptible to monopolistic gaming:* Several studies of the California market have concluded that the extreme price spikes in 2000 and 2001 were magnified by a few large generators. These generators withheld their capacity (physically or economically) with the expectation that it would increase prices.[5] Conditions needed for this strategy to work were: 1) inelastic demand in the aggregate; and 2) generator control of a mix of capacity such that withholding a unit from the market would ratchet up the MCP, ultimately benefiting its other generators. Under AOP, generators will likely alter their bidding practices to reap the same benefit by attempting to predict the impact their offers will have on market prices.[6] Under AOP, dominant participants are likely to be in a better position than small participants. In this respect, AOP pricing will discourage increased competition. Another important difference between MCP and AOP is the greater transparency of bidding behavior under MCP pricing for detecting collusive or quasi-collusive pricing behavior. The monopolistic behavior, such as capacity withholding, is easier to detect under MCP pricing since the marginal costs can be estimated.

[5] [Paul Joskow and Edward Kahn. "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000." November 21, 2000.]
[Robert Nordhaus, Carl Shapiro, and Frank A. Wolak. "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets." September 6, 2000.]
[Severin Borenstein, James Bushnell and Frank Wolak. "Diagnosing Market Power in California's Restructured Wholesale Electricity Market." August 2000.]
The authors of these reports have offered various explanations for price spikes in California: externalities, gaming problems, demand inelasticity, and lack of long-term contracts. However, these authors have nearly unanimously rejected switching from a MCP to an AOP pricing methodology considering such a move detrimental to the market.

[6] [Natalia Fabra. "Uniform Pricing Facilitates Collusion: The Case of Electricity Markets." October 2000.]

However, AOP can mitigate market prices if a bidder uses what has been called a “hockey stick” pricing strategy. A supplier using this strategy offers energy, reserve or transmission rights at prices that follow a “hockey stick” pattern: a majority of supply offered at a "reasonable" price followed by a few MWs (sometime only one MW) offered at very high price. Hockey stick pricing strategies have been commonly practiced[7] at several RTOs and ISOs. During times of tight supply and inelastic demand, these strategies can lead to high MCPs (see figure below). In the case shown in this figure and under MCP auction pricing, the price will be $110/MWh for all buyers and sellers. However, assuming the offer price for the low-value portion of the offer curve stays the same under AOP pricing, the price for buyers will be the average of offer price curve, which will be $8.71/MWh. This potential lowering of average price has been the main argument in the support of AOP pricing. Existing RTOs and ISOs with MCP-based auction markets use several straightforward market rules (mainly in the form of automatic MCP changes) to counter the hockey stick pricing strategy. These rules could also be used by Grid West.

Figure 3.1 – Example of Hockey Stick Pricing



[7] [David Hurlbut, Keith Rogas and Shmuel Oren. “Protecting the Market from ‘‘Hockey Stick’’ Pricing: How the Public Utility Commission of Texas is Dealing with Potential Price Gouging.” The Electricity Journal, April 2004, pp. 26-32.]

4.0 CONCLUDING REMARKS

Experience has demonstrated that in competitive markets MCP and AOP converge to similar prices for customers. Therefore, there do not appear to be definitive benefits associated with AOP pricing. In fact, it has been shown that AOP could aggravate market power conditions in less competitive markets by increasing costs, raising the barrier to entry for smaller players, and reducing market efficiency. Grid West should consider adopting an MCP approach for all its markets while using market monitoring measures to prevent potential market power abuses.

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1.0 EXECUTIVE SUMMARY

Seams are inefficiencies inhibiting customers from implementing transactions across control area boundaries. Examples of seams issues include differences in business protocols, market design, transmission services, and other control area practices.

This paper focuses on seams coordination between Grid West and other control areas or RTOs in the Western Interconnection. Specifically, this reference paper addresses two areas of seams coordination: 1) operational/procedural considerations; and 2) congestion management at the seams.[1]

Highlights of this paper include:

- Seams issues have been identified and discussed in various forums.
- Grid West will consider seams coordination in its proposed market and scheduling activities.
- Grid West's markets and processes should help facilitate transactions across seams arising from Injection Withdrawal Rights (IWRs) in Grid West and other rights such as financial transmission rights in other control areas.
- Grid West's markets and processes should also help facilitate real-time transactions;.
- Grid West should participate in efforts to coordinate inter-tie curtailment, outage notification, and network model development.
- Grid West's long-term efforts should focus on developing coordinated inter-control area congestion management and simplifying multiple system charges for wheeling transactions.

2.0 PURPOSE

The purpose of this reference paper is to discuss seams coordination issues potentially impacting Grid West operations.

[1] Given the differently situated regulatory regime in Canada and British Columbia, in particular, the operating assumption is that the Grid West market design will be mirrored in British Columbia, to the extent possible within that regulatory regime. Details regarding the market design in British Columbia are anticipated to be completed as part of detailed design phase of this effort.

3.0 BACKGROUND

Seams inhibit customers from implementing transactions across control area boundaries. The extra-regional boundaries of concern will be those with California, the Southwest and the Rocky Mountain area. There may also be seams issues to be resolved with parties within the Northwest Power Pool who do not join Grid West. Examples of seams issues include differences in protocols, market design, transmission services, and other control area practices.

The Federal Energy Regulatory Commission (FERC) has been encouraging the elimination of seams issues across RTO boundaries. The FERC has held technical conferences on interregional coordination among RTOs for resolving interregional issues[2]. Seams issues are important to Grid West since seams exist in operations and planning across control area boundaries with or without the formation of RTOs.

As envisioned by the Regional Representatives Group (RRG), Grid West's primary function is to provide transmission services for the region. In order to facilitate the transactions not only within the Grid West Managed Transmission System (GWMT), but also across the Grid West boundaries, Grid West will need to coordinate with other control areas and market operators: (1) to ensure that the combined day-ahead and adjustment period schedules from all the control areas are feasible; and (2) to minimize real-time, flow-related problems deriving from or affecting external control areas.

Major efforts were made by existing and developing Western RTOs (the California ISO, RTO West and WestConnect) to develop seamless western markets for transmission services with common business practices. In approving the Stage 2 filing from the RTO West filing utilities, FERC requested that the filing utilities participate in the Seams Steering Group– Western Interconnection (SSG-WI) in an effort to meet the following goals:

- Form a single market monitoring unit for the West;
- Develop the planning and expansion process through SSG-WI; and
- Work with other control areas to formalize SSG-WI as the seams resolution group for the West.

In addition, the Western Electricity Coordinating Council (WECC) Market Interface Committee has also been involved in the seams forum working to address the reliability implications of commercial issues.

[2] Federal Energy Regulatory Commission, "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design," Docket No. RM01-12-000

Some of the major seams-related issues potentially impacting Grid West operations include[3]:

- Infeasibilities of combined schedules from external systems;
- Loop flow and inefficient curtailments;
- Planning;
- Market monitoring;
- Dynamic scheduling over inter-ties;
- Multiple system charges;
- Inconsistent Available Transfer Capacity (ATC) calculations over interconnections;
- Export charges and exit fees;
- Inconsistent scheduling timelines;
- Other tariff conflicts across boundaries;
- Emergency responses and compensation;
- Sharing of regulation and reserves; and
- Outage notifications.

Grid West Basic Features include regional transmission services and scheduling, which in itself reduces seams that exist today across control area boundaries. Moreover, in its market design, Grid West will make every effort to further facilitate the transfer of wholesale electric commodities such as energy and ancillary services across its boundaries. It is expected that various sectors of the industry, standard-setting bodies, and regulatory bodies will continue to work toward resolving seams issues between various markets. Grid West will closely follow and adopt any solutions deemed prudent and desirable to the Grid West stakeholders.

Coordination already exists today between interconnected control areas that work together to maintain reliability. Building on the current coordination agreements in the WECC (such as loop flow curtailments; coordinated scheduled outages and notification of forced outages; and long-term planning), Grid West should focus efforts on facilitating transactions across the regional borders and improving operational efficiencies through coordination with existing RTOs or transmission providers in the West.

3 RTO Seams Workshop, "Congestion Management And Firm Transmission Rights: Seams Issue Paper for Workshop," Salt Lake City, Utah, Embassy Suites Hotel, June 20, 2000.
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4.0 REDUCING SEAMS IN GRID WEST

The primary objective defined by the SSG-WI group is to "facilitate a seamless western market." It may take a long time to achieve this objective. In the interim, Grid West should take advantage of the existing forums and coordination processes. It should work with the adjacent RTOs and transmission providers to coordinate business processes. This coordination effort should focus on producing benefits for Grid West, its Transmission Customers and existing RTOs.

4.1 Market Activities and Timing Coordination

Grid West should consider the ramifications of its scheduling activities and market timelines to facilitate Transmission Customers' transactions across the seams. The timelines of day-ahead scheduling, daily reconfiguration service (RCS) and the consolidated control area (CCA) reserve market should be coordinated with the adjacent control areas. In addition, the definition of the time frames for the Injection/Withdrawal Rights (IWR) for the yearly and monthly RCS auctions should also take into consideration the time frames for financial/firm transmission rights (FTR) in the adjacent control areas and markets.

For example, in order for Transmission Customers to complete a transaction involving both Grid West and the California ISO, the daily RCS should close before the California ISO's day-ahead market process so Transmission Customers can acquire or exchange necessary IWR rights. Scheduling in the Grid West transmission segment is relatively certain if the Transmission Customer holds the IWR rights, while scheduling in the transmission segment inside California is determined through a day-ahead bidding process conducted by the California ISO. In this case, a Transmission Customer with the necessary IWRs in Grid West can make the transaction take place by acquiring the necessary financial transmission rights in California beforehand and constructing their bids/offers as price takers to California's day-ahead market.

Clearly, the above transaction is more difficult to arrange if the Grid West RCS market has not been completed before the deadline of California's ISO's day-ahead market and the Transmission Customer did not secure its IWRs in Grid West. This is because the procurement of rights in RCS is critically dependent upon whether there are competing rights holders who will release their rights.

Since the Northwest utilities are generally considered to be capacity-rich utilities, they can capture additional financial benefits by selling additional reserve services to adjacent RTOs' ancillary service markets, such as those in the California ISO. As a result, the scheduling rules, timeline and activities should accommodate the scheduling of reserve exports. Grid West should develop a methodology to account for the reserve use of transmission in its analysis and update of Available Flowgate Capacity (AFC); and a mechanism for facilitating capacity-only transactions.

4.2 Facilitating Transactions Across Seams

Through its market and scheduling processes, Grid West should facilitate transactions crossing the control area boundaries between Grid West (the GWMT) and external control areas; and between the CCA and other host control areas.

Grid West should explore opportunities to facilitate trading across the seams. Since the CCA and other host control areas have separate Interconnected Operations Services (IOS) requirements and separate reserve requirements, a Transmission Customer within the CCA may wish to schedule reserve capacity to another host control area or external control areas. Grid West should facilitate sales of reserves across control area boundaries.

Currently, the California ISO has a 10-minute scheduling cycle for real-time energy resources. While entities outside the California ISO may bid at hourly intervals, they are not able to respond to the dispatch instructions and price signals from the California ISO. In order to avoid financial risk and missed opportunity associated with resources in the GWMT system, Grid West could consider scheduling at the same granularity used in the California ISO's real-time market.

Furthermore, Grid West should have consistent definitions of products, if possible, with external control areas and markets. For example, although the nature of Grid West's IWRs are different from California's Firm Transmission Rights (FTRs), a consistent duration, starting and ending time, and delivery periods will generally be beneficial for all Transmission Customers.

4.3 Full WECC Model

In the current proposal by the California ISO, a full network model will be deployed in the forward markets and in real-time operation to manage transmission and congestion. The full network model has simplified the representation for transmission facilities outside the California ISO. The

obvious benefit of using a full network model is accurate representation of the flow effects on all transmission paths in the region.

The network model for Grid West has not yet been defined. There are benefits if all the western RTO and transmission entities have complete network representation in the day-ahead scheduling and real-time operation. The congestion management approaches described in Section 5 depend on the use of full network model to identify loop flow contributions in day-ahead and in real-time operation. At a minimum, a full network model can be used to identify the loop flows from the set of known schedules. Grid West will probably use a full network model for the same reasons as California, namely the identification of external effects.

WECC has been leading an effort to review the potential of a single West-wide system model (WSM) for network applications. The concept would be to ensure interoperability and to comply with NERC's requirements from the August 2003 Northeast Blackout recommendations. The WSM model would merge individual utilities' models and would span the entire WECC. The model, if implemented, can also provide, via CIM XML, access to Grid West's Energy Management System (EMS). Therefore, Grid West may actually import the WECC network via CIM XML and keep it updated (for external portions) by partial updates from other reliability entities. This effort may result in the capability of seamless system analysis for both planning and operations studies to be based on real-time system conditions. It would also improve consistency and provide a foundation of common information needed for network application implementation by individual control areas.

4.4 Outage Coordination and Notifications

Outages not only affect the AFCs within the immediate control areas, but also the AFCs in the adjacent control areas. The control areas in the Western Interconnection need to exchange transmission outage data through a coordinated process. Each control area should utilize network applications to analyze planned critical facility outages to determine its effects on the reliability of the transmission system. In addition, the full network model, if used by all control areas, needs to be updated to reflect the topology change of the transmission system due to planned and unplanned outages. The control areas in the western region need to contact each other as soon as possible if these changes result in unacceptable system conditions and to work with one another to develop remedial steps as necessary. WECC has been involved in implementing outage information sharing systems (Grid Alert System and WECCNet messaging system). Grid West should take advantage

of these systems and follow the protocols set forth by WECC and NWPP notification requirements.

Further, current Northwest transmission users can access the California ISO's outage information as the schedule deadline approaches, while California ISO and transmission users could learn of transmission outages in the Grid West region from the 45-day outage planning process. The lack of advance outage information from the California ISO should be resolved between the California ISO and Grid West. The Western Market Interface Committee (WMIC) Seams Working Group also produced a report recommending that the Northwest's 45-day outage planning process would be a good model for the rest of the West to follow in dealing with these seams problems.

4.5 Schedule Checkout

Grid West should encourage the implementation of an automatic checkout service, allowing other control areas in the region to obtain transaction data to improve operational efficiency. Automation will benefit control areas in the region.

The Western Interchange Tool (WIT) is WECC's effort to move to electronic scheduling. Implementation of the WIT can result in a fully automatic system of electronic scheduling that would eliminate the need for after-the-fact accounting for inadvertent flows. Electronic scheduling should ensure scheduled interchange is correct. This will improve accounting and reporting efficiency. The current scheduling environment involves manual schedule checkout via telephone to verify schedule and actual interchange and may lead to mismatches.

4.6 Multiple System Charges

Multiple system charges, especially for short-run usage, are generally considered to be detrimental to economic efficiency since more efficient generation resources may not be used. To eliminate multiple charges for system use, two competing interests must be balanced. For efficiency's sake, elimination of short-term charges encourages the best use of transmission resources. However, the embedded costs of the transmission system must also be recovered from users without creating substantial shifts in fixed-cost responsibility. This issue will likely need a common agreement among all transmission providers in the West.

4.7 Common Scheduling Platform

A single market interface has been discussed, through which users of the Western interconnected transmission system can, on a day-ahead basis, schedule the use of the transmission system and bid into markets operated by different control areas or RTOs. This objective has often been referred to as "one-stop shopping." This is a difficult goal to achieve without a common standard of scheduling operation. One possibility is to allow the development of scheduling agents who can serve as the "one-stop" scheduling agency to interface with Grid West, California ISO and other transmission providers. Grid West should continue making efforts to streamline the scheduling operation.

4.8 Interfaces with Non-market Control Areas

The Grid West interfaces with market-based control areas such as the California ISO and non-market control areas that are largely similar in dealing with scheduling and procedural aspects. For example, there are no differences in tagging transactions from market-based and non-market control areas. Outage coordination and loop flow curtailments are also similar seams issues. Information sharing is also a common coordination solution.

For interfaces with market-based control areas, market rules alignments should be considered in general, such as market timing coordination, monitoring and product consistency. Moreover, efforts should be made to allow Transmission Customers to freely choose which market to participate in so that any large price discrepancies at the seams can be reduced.

For non-market control areas, Grid West will continue to use the current practice or will develop new agreements to deal with procedural and commercial seams issues. The formation of Grid West in itself will generally reduce the seams between Grid West and non-market control areas since they will not have to transact with multiple transmission providers. Moreover, many control areas in the Northwest are also transmission users and they should enjoy many other benefits of Grid West that may not be available to them today, such as the opportunity to participate in the CCA's reserve markets, coordinated planning and expansion services that impact them.

5.0 REDUCING SEAMS IN TRANSMISISON CONGESTION

For the Western Interconnection, transmission congestion problems at the seams are mainly related to the loop-flow curtailments on the major loop in the West, which are managed through the Unscheduled Flow Mitigation Plan (UFMP) of the WECC. The UFMP requires a sequence of steps, starting with the path owner's

schedule modifications, followed by operation of the phase shifters on the system and ending with curtailment of schedules on other paths that contribute to loop flow on the affected path.

Currently, all of these actions have to take place in real time and have an impact to the reliability of the system. Testing the feasibility of all combined schedules in the day-ahead or later pre-real time periods for the entire region would be desirable.

5.1 SSG-WI Proposal

The Congestion Management Alignment Working Group (CMAWG) under the SSG-WI forum was developed to propose coordinated scheduling and congestion management procedures that will result in feasible day-ahead schedules for the combined control areas that explicitly recognize parallel path flows in the Western regional transmission system.

The preliminary proposal[4] by CMAWG was for an iterative process between the markets, in which the accepted schedules of the different RTOs or control areas are adjusted for mutual consistency and region-wide feasibility. It was generally agreed that day-ahead congestion management is needed (and expected that it would be available) in each RTO or control area to obtain a single set of schedules across the West given different congestion management processes. The implementation of schedules that are feasible in the day-ahead (or other pre-real time period) would significantly reduce the need for and amount of loop-flow curtailments that impact the WECC system. The proposal assumes there will be a single market interface and a similar congestion management process in the different markets. While there were no details or assurances that such a process would converge, analogies with other proposals suggested it would be effective.

Given the diverse approaches of managing congestion and uncertainties in Grid West's new approach and California ISO's LMP-based energy market, as well as the de-emphasis on day-ahead congestion management in Grid West, such a framework will have to be revamped to achieve the same goals.

The operation of controllable devices, mainly the phase shifters, has a major impact on the loop flows in the Western Interconnection. The study by the

[4]SSG-WI Congestion Management Alignment Working Group, "Straw Proposal for Inter-RTO Day Ahead Scheduling and Congestion Management," //www.ssg-wi.com/documents/269-081903_030815_CMAWG_Straw_Proposal_CLEAN.doc.

WMIC RTO Seams Phase Shifter Working Group[5] lays out some foundations for developing a mechanism of coordinated operation. One of the ideas proposed in the study is to link phase shifters to additional flowgate rights, which were originally meant to be financial in nature. But these rights can be physical as well.

Regardless of the difference in congestion management and market operations in the West, all RTOs or control areas should continue to evaluate coordination issues involving information exchanges, network modeling and the impact of each other's congestion management procedures.

5.2 Virtual RTO and Virtual Dispatch

In the Eastern interconnection, a coordination model called Virtual Dispatch[6] has emerged as a result of efforts spent in the pursuit of better coordination at the RTO seams.

A virtual RTO is a tightly coordinated group of transmission providers providing transmission service over a broader geographic area. The coordinated dispatch produced under a virtual RTO is called virtual dispatch. The crux of a virtual RTO is information is exchanged between RTOs to allow coordination of some activities between RTOs in the same manner that they are coordinated within an RTO. A virtual RTO also allows for region-wide market monitoring.

The NYISO and NE-ISO[7] have documented a technical definition of a virtual regional dispatch process. A regional dispatch Pilot Test Program was discussed. This program is still in its testing stage; ISO-NE and NYISO stakeholders will jointly develop the details of the Transmission Customer-based solution. In the interim, PJM and MISO are discussing[8] a Joint Operating Agreement for interregional coordination and congestion management to achieve a virtual RTO.

Grid West should monitor the development of virtual RTOs to leverage their design and models if possible and desirable.

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[5] WMIC RTO Seams Phase Shifter Working Group: **"**Phase Shifter and Controllable Devices in Developing Western Interconnection RTOs," June 15, 2001 http://www.ssg-wi.com/documents/116-Ph_Sh_Rpt_Seams_PST_Rep.pdf

[6] EPRI, "Virtual Regional Transmission Organizations and the Standard Market Design" January 9, 2003.

[7] ISO New England and New York ISO, "Virtual Regional Dispatch Concept, Evaluation, and Proposal", May 19, 2003

8 Andy Ott, "PJM – MISO: Achieving a Virtual RTO through A Joint Operating Agreement." Harvard Energy Policy Group. September 26, 2003

5.3 Curtailment Coordination

Loop flow curtailment is one special aspect of congestion management across seams. When schedules across inter-ties must be curtailed to resolve overloading, the WECC members resort to the use of the Unscheduled Flow Mitigation Plan. This plan is a negotiated administrative mechanism to address loop flow problems in the interconnection. Although the plan serves as an important tool for maintaining system reliability, it has two major limitations.

- First, the economic efficiency of the actions is generally not considered in the curtailment decision. The present practice for curtailments is that security takes precedence and schedules are curtailed according to what is doable. Consequently, large curtailments that may not be efficient to relieve the overloading are ordered. In addition, inconsistent curtailments from different sides of the ties often take place. The economic value of using the transmission is not recognized in the procedure.
- Second, the curtailments are initiated at or near real-time operation and Transmission Customers in general desire sufficient lead-time.

Grid West should continue to follow the UFMP. Grid West should, however,strive to reduce curtailments through internal market and seams coordination processes. These include the processes that follow:

- A complete view of all schedules within Grid West in the day-ahead period lets Grid West identify potential curtailment conditions within Grid West or WECC beforehand. Furthermore, the implementation of Grid West's scheduling adjustment process will result in fewer curtailments for the schedules in Grid West. Lastly, when a full WECC network model is used, Grid West can anticipate the aggregated impact of all its schedules to the major WECC loops and vice-versa.
- Grid West should facilitate and consider market mechanisms whenever possible that address the relative value of the various transactions cross seams in implementing curtailments. Assuming Grid West is acting as the scheduling entity for its Transmission Customers, a desired cut may be distributed to Grid West customers using economic methods, if possible.[9]
- Grid West should also consider information exchange and agreement with other scheduling entities in the Western Interconnection to obtain

[9] This remains to be explored.

a complete view of all schedules, and eventually to implement market mechanisms to adjust schedules across seams between Grid West and other market or non-market entities.

6.0 CONCLUDING REMARKS

Coordination already exists today between multiple interconnected control areas to maintain a reliable transmission system. The resolution of seams issues depends not only upon the development of technical solutions, but also upon the organizational and market structures. Grid West should actively participate in the seams resolution process, while developing workable agreements and procedures with the neighboring control areas and market operators.