PAPERS ON CONCEPTUAL FRAMEWORK

FOR GRID WEST MARKET AND

AND OPERATIONAL DESIGN

RELEASE DRAFTS

MAY 12, 2005

Prepared by

TRANSMISSION SERVICE

LIAISON GROUP

(This page intentionally blank)

Note to Readers: *This overview paper has been prepared by the Transmission Service Liaison Group (TSLG) to provide an overview of the conceptual framework for implementing Grid West's Basic Features in a market and operational design. The information provided in this updated draft is current as of the date shown below and contains modifications made since the first version was posted in March 2005.*

The preparation of the white papers described in this overview paper is drawing to a conclusion. This updated overview paper draft is being provided to assist the preparation of those who will be attending the May 25-26 Seminar. The overview paper will help the reader understand how the individual white papers fit into the larger context of the Grid West market and operational design.

1.0 GRID WEST MARKET & OPERATIONAL DESIGN

1.1 Contents of the Overview Paper

This overview paper has been prepared by the Transmission Service Liaison Group (TSLG) to help interested parties understand TSLG's proposal materials. It explains what the TSLG has set out to accomplish and provides background information about the transmission problems and opportunities the TSLG proposals seek to address. It explains the relationships among the various subject areas and introduces the white papers that are the focus of the TSLG's current activities.

Section 1 of this paper provides general background information. Section 2 explains how transmission providers currently manage contractual obligations and describes the operational challenges created by the present approach to transmission capacity management. Section 3 provides an overview of core elements of the TSLG's proposal for a new approach to providing transmission service. Section 4 describes voluntary control area consolidation and the services Grid West will provide to enable such consolidation. Section 5 introduces the white papers and explains how they fit together to define the conceptual framework of Grid West's market and operational design. Appendix A provides summaries of all white papers and reference papers produced by TSLG to document the conceptual framework for Grid West's market and operational design.[1]

[1] This Overview Paper together with the other Whitepapers and Reference papers, were developed in a manner that considers federal and state jurisdictional roles and relationships in the United States. 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

1.2 TSLG's Assignment

The TSLG's assignment is to develop a market and operational design framework for Grid West's Basic Features. The complete design work is divided into four layers, each with an increasing level of complexity. The purpose of the first two layers is to develop a conceptual framework prior to Decision Point #2, while Layers 3 and 4 will increase design detail to support Decision Points #3 and #4.

a. Layer 1 – Major functions were defined in 2004.

b. Layer 2 – Methodology, responsibilities, and costs are to be identified in 2005.
   - A series of white papers has been developed to describe the conceptual framework and address major design features in some detail.
   - The set of reference papers has been developed to cover topics that are applicable to more than one of the white papers.
   - Figure 1.1 shows the titles of all the papers, organized by the TSLG work modules with which they are associated. A complete list of all the above papers with their summaries is also provided in Appendix A.
   - A glossary of Grid West terms used in the papers will also be provided on the Grid West website.

c. Layer 3 – Will develop protocols for market rules, business rules, transactions, etc.

d. Layer 4 – Will prepare tariffs, functional specifications, interface designs, detailed technology requirements, etc.

1.3 Market Monitoring

While market monitoring will be a part of the complete Grid West structure, the organizational form, authority and scope of the market monitor's activities are beyond the scope of TSLG's assignment. However, in the white papers, potential market power issues are described when they have been identified and possible mitigation strategies are discussed. In general, the organization of formal markets for transmission rights, reserves and balancing energy are expected to assist market monitoring activities.

---

possible within that regulatory regime. Details regarding the market design in British Columbia are anticipated to be completed as part of the detailed design phase of this effort.

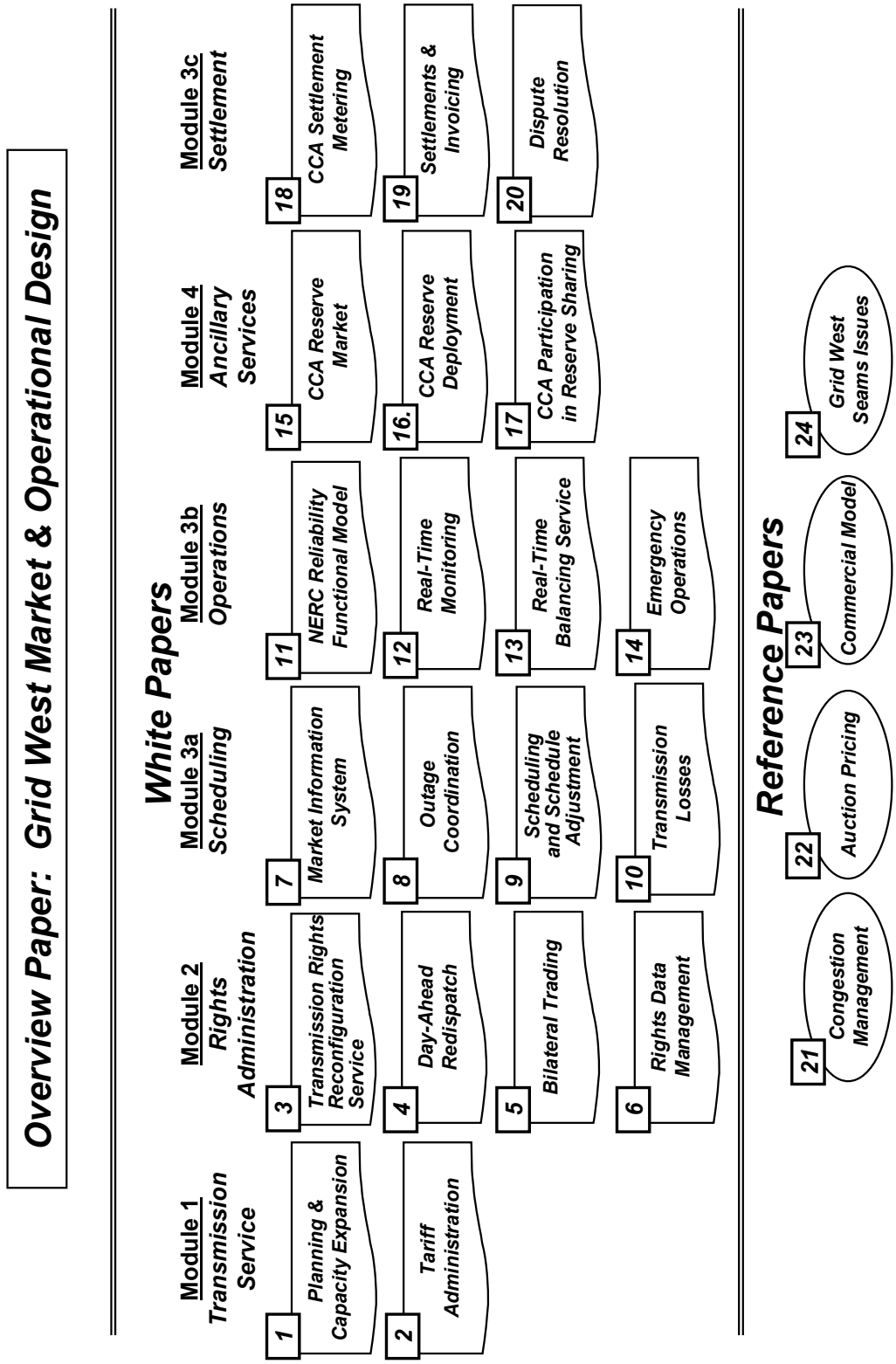


Figure 1.1 Chart of TSLG paper describing the conceptual framework of Grid West's market and operational design. Paper numbers are keyed to the list of paper summaries provided in Appendix A.

2.0 A COMMERCIAL USAGE MODEL TO MATCH PHYSICAL REALITY

This section explains how transmission providers currently manage contractual obligations and describes the operational challenges created by the present approach to transmission capacity management. It provides valuable background on both the evolution of the regional grid and the rationale for the need to change the commercial usage model.

2.1 Interconnected Systems

a. Transmission Function & Value. The function of a transmission system is too reliably and economically delivery energy from generation to loads. Reliability of supply is a clear expectation in our society. To meet this expectation, the transmission system must be designed and operated to withstand the contingencies that occur over time; for instance, the loss of a generator due to a mechanical failure or the loss of a transmission line due a lightning strike.

   At the same time, the economic value of the transmission system's delivery capacity is based on the value of the resources it can deliver. This is a reflected value rather than a direct value, since a transmission line has no value without energy to deliver. As a result, generation really doesn't compete with transmission; rather, transmission enables competition to occur between remote and local generation.

b. Reliability and Economy. Transmission systems were relatively straightforward in the beginning; a line was built from a generator to a load. In the West much of the early transmission was built from remote hydro resources to either cities or mining centers.[2] There was an early recognition of opportunities for improvements in reliability and for obtaining economic savings if these simple systems were interconnected. As interconnections grew, utilities were able to provide back-up to each other for contingencies, and they were also able to take advantage of load and resource diversity to trade energy among themselves to reduce the cost of serving their respective customers.

   Whenever an interconnection of AC systems occurs, a new joint system is created, which becomes in effect a single, very large machine. All the generators in an AC network are synchronized, i.e., they all operate at the same frequency. Further, because of governor action, they respond jointly to

[2] Thomas P. Hughes, Networks of Power, Electrification in Western Society, 1880-1930, Johns Hopkins University Press, Baltimore, MD 21218, 1983, pp. 282-283.

maintain standard frequency when there are changes in load or loss of generation or transmission. The transmission system provides the ligaments that tie the generators together and connect them to load.

Such a multi-owner regional system is by nature a single system electrically, and facility ownership has no bearing on power flow. The flow of power through the interconnected network is governed by system physics, i.e., the systems topology, its line impedances, and the location of generation and load. Because there are no electrical valves[3] in the transmission system, the ability to alter power flows occurs primarily by changing the generation dispatch, i.e. the pattern of generation injections at various locations in the system.

c. Problem of the Commons. Whenever a single system is created in which there are multiple owners, there will be what has been called the "problem of the commons," i.e., the temptation for each user/owner to maximize its own benefits from a shared resource without regard for the detrimental effects on other users.

   This problem of the commons is complicated in the case of interconnected electrical systems by the fact that every action of one party affects others to some degree. In addition, each of the multiple owners has different levels of investments, and those investments were made at different points in time. This leads to different perceptions about each owner's appropriate usage share in the combined system. Over time, a set of usage rules (the contract path model) developed for the interconnected transmission system to define each owner's share of the jointly created transmission capacity of the system. However in recent years there has been increasing concern that the current set of usage rules is inadequate.

2.2 Do We Need a New System Usage Model?

a. The Contract Path Model. Today, transmission owners provide transmission services using an approach that is known as the contract path model. The base assumption of the contract path model is that separate owners can act autonomously. However, once interconnections began, this was never really true. As explained in more detail in Section 2.3, the contract path model was workable when it was applied to early interconnections because the transmission network was simpler, had far fewer interconnections, and there was sufficient "margin" in the system to compensate for the mismatches

[3] Phase shifting transformers, also called phase angle regulators, can provide a limited degree of power flow control. They are located in a few strategic locations to meet specific needs, however, generation dispatch remains the primary means for controlling power flow in the network.

between the way the contract path model assumed energy would flow along the "contract path", and how energy actually moves across the system. These mismatches have come to be called unscheduled flow or, more commonly, "loop flow."

b. Contract Path Workability. The contract path approach is becoming less and less workable over time as the system is more frequently operated closer to its physical limits. At the same time, methods used by transmission providers to mitigate the problems of the contract path model (described in Section 2.4 below) are not as effective as they need to be, because the contract path model is not based upon actual power flow effects.

c. A Flow-Based Model. A new and practical commercial service model of system usage is needed that will align transmission right issuance and scheduling with the physical realities of power flow in the transmission system. To meet this objective of the Regional Proposal, TSLG has developed a flow-based methodology (described in Section 3 of this paper) that recognizes that the actions of each transmission user affect all other transmission users to a greater or lesser degree based on system physics.

2.3 The Challenges of the Existing Contract Path Usage Model

a. Problems & Opportunities. During the summer of 2003, the Regional Representatives Group (RRG) developed a list of problems and opportunities[4]. The contract path model of system usage was identified as a significant factor in underutilization of transmission capacity. An opportunity exists to develop improved usage rules that allow existing capacity to be better utilized while still maintaining system reliability.

b. Contract Path Assumptions. The contract path model is a simple "transportation" model. For commercial purposes, transmission is assumed to be provided, and power is assumed to travel (or flow), on specific lines as if MWs were cars on a highway network. This simplifying approximation was acceptable when the pattern of interconnections was fairly simple and there was surplus capacity in the transmission system. However, this simple model has been retained past its useful life, because of its apparent simplicity and because of uncertainty about the outcome when converting existing obligations from one usage model to another.

c. A Growing Mismatch. The mismatch between the simple contract path and physical reality grew with the rapid growth of the system after World War II.

[4] "Regional Representatives Group, Regional Transmission Problems and Opportunities List, Organized by General Categories - Update and Accompanying Notes," August 14, 2003, http://gridwest.org/Doc/RRGA_RefinedListClean_Aug142003.pdf.

In the 30 years after World War II there was a burst of transmission construction.

- Canada and the Pacific Northwest were tied to California by the lines that make up the elements of the Pacific Interties.
- Transmission was strengthened within the greater northwest as interior hydro and coal-fired resources were developed.
- Ties were closed at Glen Canyon and in the Four Corners area that connected Arizona and New Mexico to Colorado and Utah (and from them to the greater Northwest).
- Transmission was built to import coal-fired resources into California from Arizona and New Mexico.

Around 1970, the completion of the major interconnections described above "closed the loop" and gave the Western Interconnection its current system topology. Disputes quickly arose among the owners operating different portions of the transmission system because of inherent mismatch between actual system flows and the contract path model. This mismatch was dubbed *"loop flow."*

d. Loop Flow. Loop flow is the reality that belies the fiction that each path owner can act independently of other operators. Years have been spent in a fruitless debate over who the loop flow culprits are, when the real culprit is a commercial use model that doesn't square with reality. Figures 2.3b shows the assumed path of energy injected in system T and withdrawn in system R with system S providing transmission service. Figure 2.3b shows what actually occurs. Components of transmission flow move across the entire system, following the past of least resistance. There inability to recognize the impact on the physical system is the inherent flaw in the contract path model.

Figure 2.1a. An assumed contract path power flow over the facilities owned by systems R, S and T.

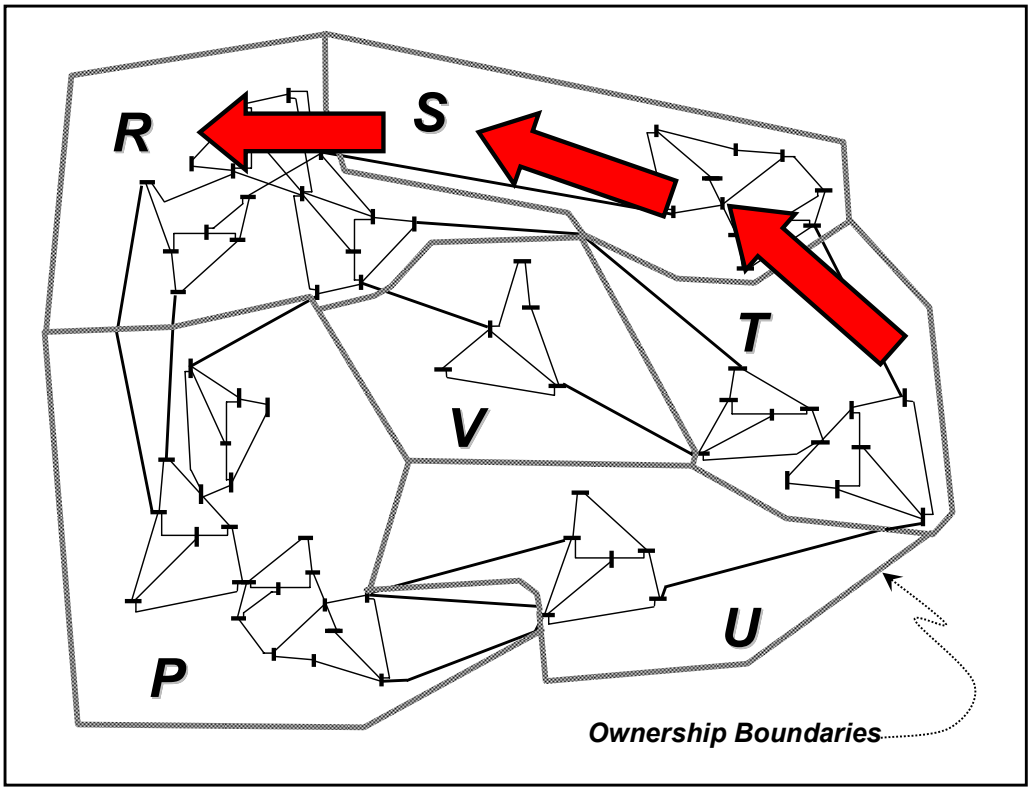
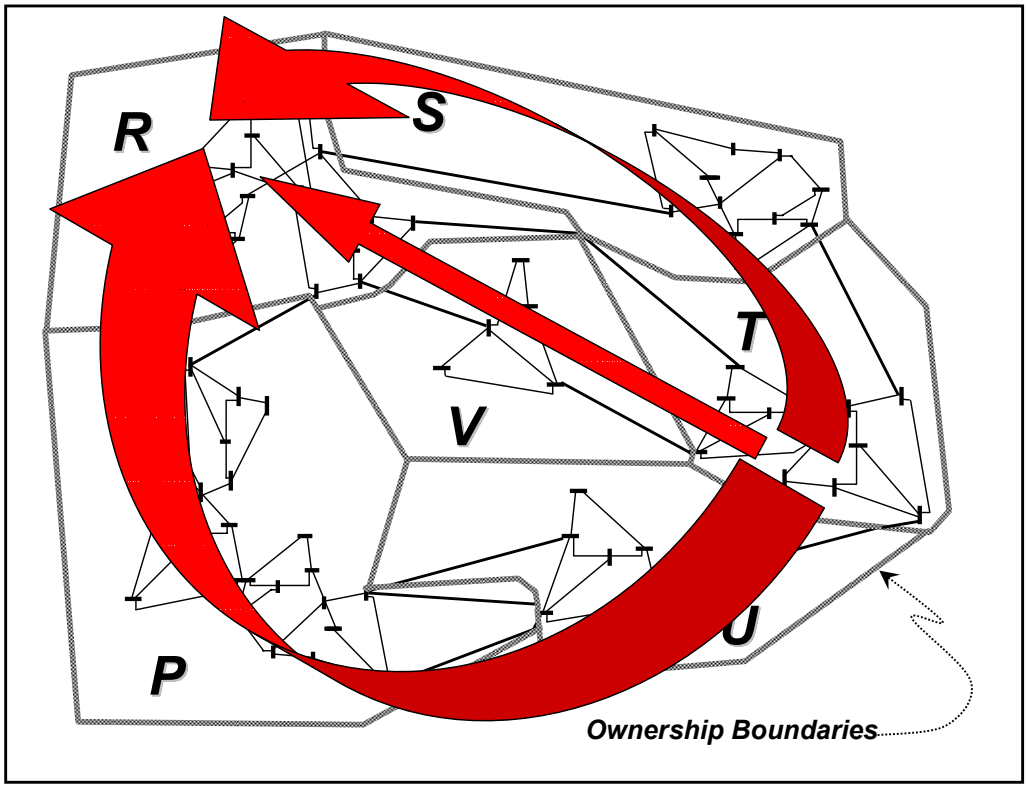


Figure 2.1b. A schematic representation of the actual power flows associated with the contract path flows shown in Figure 2.1a.



e. Contract Path Inefficiencies. Loop flow is an evidence of the inefficiency forced into system operations by use of the contract path model. In order to protect an owner's autonomous use of its share of system capacity, limits are placed on other owners' use of their own facilities. These limitations endeavor to protect system reliability, however because they are made *a priori*, they lead to underutilization of transmission system capacity. The contract path model provides has no reasonable economic means for transferring usage rights between owners as transmission user needs change.

f. Inability to Predict Loop Flow. An added problem with loop flow is that it cannot be predicted in advance under today's commercial arrangements. As a result, when loop flow problems occur in real-time, operators must use non-economic adjustment measures, i.e., the curtailment of schedules, to correct path overloads. Curtailments are made based on an owner's view of only its own system. Sometimes, these curtailments lead to no actual change in flow because generation dispatch is unchanged. The energy is simply

rescheduled through other 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. This is not particularly effective, but it is the only tool available to operators today.

2.4 Mitigating Contract Path Model Problems

When the network was growing rapidly, temporary excess capacity tended to lessen the impact of contract path model problems. As utilization rose and transmission owners began to face unexpected costs,[5] efforts were made to adjust the contract path model have been made to mitigate loop flow effects and find a way to "live with" the problems.

a. Building Ahead of Need. When transmission systems were expanding rapidly prior to the 1980's, there was a tendency to build capacity ahead of need. This occurred in part because transmission line investments are "lumpy," i.e., you get the entire capacity of a transmission line when the line is energized, not just the capacity you need at the time. Surplus capacity, when it exists, tends to mask the impact of the actual flow to scheduled flow mismatch, making it more tolerable.

   Because the system was growing quickly in the 1970's, the extra capacity from a project would be needed in one or two years to move additional generation, so the economic burden of extra capacity was small. These conditions no longer apply. System load is growing slowly. New generation tends to be gas fired, may well be owned by a non-utility entity, and located close to load. New investment in transmission has lagged far behind load growth over the past 15 years[6], and public resistance to transmission line siting is much more vigorous than it was 20-30 years ago.

b. Simultaneous Path Ratings. Even with surplus capacity designed into early system by the construction effects, there were still many hours when the presence of loop flow created operational problems. As a result there was clear appreciation of the need to recognize (at least in part) the effect of the actual flows on the major parallel paths in the Western Interconnection. That need led to simultaneous ratings of parallel paths. Simultaneous path ratings provide an approximate, flow-based division of system capacity between

---

[5] In spite of the difficulties of loop flow, no system has ever proposed cutting its interconnections to other systems in the West. This is unspoken testimony to the great value of interconnected transmission systems for both economic savings and system reliability.

[6] Keeping Current – Wanted: One-utility transmission for the Pacific Northwest, Bonneville Power Administration, March 2005, p. 2,(http://www.bpa.gov/corporate/pubs/Keeping/05kc/kc0305.pdf).

parallel paths. While the simultaneous ratings nomograms[7] provide bounds for operations, they do not provide a way of determining what operating point is "best" or a mechanism for dynamically allocating path capacity.

In order to protect autonomous use by each path owner, the scheduled use of a path must be limited to the path rating even if actual flow is below the rating. At the same time, actual flow also must be limited to the path rating, even if the schedule was below the path rating. The requirement to abide by this dual constraint causes capacity to go unused. The full system may be capable of moving more energy, but there is no way to enable heavier use on one owner's system if the owner of the parallel path is to be able to autonomously exercise its "share" of the simultaneous rating. While the simultaneous rating process has reduced disputes among the owners, it has not resolved the underlying problem of underutilization.

c. Coordinated Operation of Phase Shifting Transformers. Another mitigation measure taken over the past 20 years is the installation and coordinated operation of phase shifting transformers[8] to partially regulate loop flow. Because the range of such devices is limited, they can only reduce loop flow but not eliminate it. Their operation is not without cost, because altering system flows by increasing phase angle also raises system losses. As with path rating, the consequences of the mismatch problem are mitigated but not resolved.

d. Increasing Problems. The difficulty of reconciling the contact path mismatch with the realities of system physics will continue to increase.
   - There has been limited transmission construction over the past decade, yet network usage continues to grow. The combined effect reduces the slack in the system that previously made tolerable the mismatch between scheduled and actual flows.
   - New construction will only make network topology more complex and increase the number of places where the mismatch between actual flows and scheduled flows creates operational problems.
   - Passage of the Energy Policy Act of 1992 opened wholesale market access to the transmission system and increased the number of transactions the network needs to accommodate.

---

[7] A nomogram is a graphic representation of the interdependence among transmission paths. These graphs show the tradeoff that must be made in reaching a simultaneous maximum flow. As flow is increased on one path it must be reduced on a parallel path.

[8] Also called phase shifters or phase angle regulators, these devices installed in one of two parallel systems, can provide limited control of power flow by altering the apparent phase angle between their terminals and force (or draw) flow onto (or from) the parallel facilities.

- The addition of new generation has become difficult, especially for remote resources like wind generation.
- Available transmission capacity is in short supply when measured using the contract path usage model. However, studies of rated paths show that actual flows approach rated capacity in a relatively few number of hours each year.

2.5 Moving to a Flow-based Usage Model

As the preceding sections demonstrate, the old contract path model is not an effective tool for making best use of the transmission system. Its basic assumption of the contract path model is untenable, namely, that separate owners can act autonomously. To address the problems inherent in the contract path model, a flow-based methodology is needed.

a. The modifications of the contract path model described above trim owner actions to a degree, but they offer no systematic, simultaneous approach to deal with actual flow effects.

b. The establishment of the Pacific Northwest Security Coordinator (PNSC) was a first step to looking at the combined real-time effects of system usage for the Northwest Power Pool control areas; however, the commercial model used for scheduling remains unchanged.

c. A structural change is needed, to reconcile the commercial model with system physics, thereby recognizing the effect that the actions of each transmission user have on all other transmission users.

3.0 THE FLOW-BASED INJECTION-WITHDRAWAL MODEL

3.1 Why is the Proposed Flow-based Model Better?

a. Desired Model Characteristics. A good commercial transmission model must align usage with physical realities, and it must be practical to implement.[9] The Grid West proposal for an Injection-Withdrawal model meets these criteria:
   - It is consistent with POD/POR designations in pre-existing transmission rights.
   - It does not require the user to be a network expert.
   - It is adaptable as the network changes.

b. Implementing a Flow-based Model. Due to the externalities (i.e., loop flow) previously discussed, implementation of a flow-based usage model is most practical when done over large regions of an interconnection. The California ISO (currently moving to a flow-based model) and Grid West are each large enough to increase grid efficiencies in its region, and both offer another key requirement for a regional transmission capacity manager using an injection-withdrawal usage model – a single, independent "gatekeeper" for use of system capacity.
   - The capacity manager makes evaluations of existing commitments and future use based on a grid-wide, flow-based examination of the whole system as an integrated regional network.
   - While the governance of the entity charged with the capacity management function must be responsive to regional needs, it must at the same time be independent of the market participants and not have a stake in market outcomes.
   - Grid West is designed to meet this need for a capacity manager for the region's transmission system capacity. Grid West's function is

[9] The region's first attempt at using flowgate rights in RTO West Phase 1 was too complex for practical implementation. The flowgate, physical rights model required each party to maintain a large, continually changing portfolio of rights on a set of critical flowgates. Limiting the number of critical flowgates to be considered was an approximation made to ease the user's burden. However by only considering a given set of identified constraints, adaptation was difficult as the system changed. If a new flowgate were deemed critical, each user's portfolios of rights would have to be restated each time a change occurred. However, the *coupe de grace* of this approach was the intractable problem of converting pre-existing rights to a distributed set of fractional rights. No unique set of such rights existed that would be agreeable to all parties.

analogous to the function of an air traffic controller managing usage of shared air space.

3.2 Pre-conditions for Adopting a New Flow-based Model

In order for Grid West to adopt a flow-based model acceptable to regional users, the following conditions must be met.

a. New services should be made available to make better use of the system.

b. The pre-existing transmission rights should be preserved and allowed to be used as they were in the past.

c. The implementation of the new model should avoid known or foreseeable market power problems and not create gaming opportunities.

d. There needs to be a reasonable and reliable transition path from today's operational model to putting the new model into operation, one that does not preclude the ability to make adaptations as system needs may change in the future.

3.3 General Features of the Grid West Flow-based Model

The general features of the Grid West flow-based model are responsive to goals and objectives described in the Regional Proposal.

a. Pre-existing obligations and agreements are unchanged in order to preserve pre-existing transmission rights. Only voluntary choices made by right holders will alter their current rights.[10]

b. A flow-based methodology with injection and withdrawal rights is adopted using a central administrator (Grid West) to manage the use of transmission capacity and to recognize the "one-system" (i.e. flow-based) reality of the regional system.

c. One-stop shopping for transmission services across the network is implemented through Grid West which will include transmission planning, capacity expansion and a single queue for long-term transmission service requests (one year or longer).

d. Transmission right reconfiguration services are implemented to enable better access to available capacity. These services combine release of capacity by transmission right holders with Available Flowgate Capability (AFC)[11] to

[10] See Section 3.2a for more discussion on pre-existing transmission rights. Discussion of participation of pre-existing right holders in the Reconfiguration Services is provided in Section 3.3b and 3.3b.

[11] The term Available Transmission Capacity (ATC) has been used with the contract path model to designate an owner's uncommitted contract path capacity. In a flow-based method, the contract path no

provide wider trade in transmission rights. This improves access to short-term services (from hourly service for the next operating day up to service for a full year).

e. Voluntary consolidation of control areas using a day-ahead reserve market and a real-time balancing market is enabled, consistent with the Regional Proposal.

f. A staged implementation will be used for building up Grid West's Basic Features. The implementation plan will allow functionality to be increased over time with a cycle of testing, user training and successful operation. The process will be repeated each time new features are added. This has proven to be a successful, cost-effective approach compared to a "big bang" start with all features at the outset.

3.4 Providing Transmission Service

a. An Incremental Change. Early in the first layer of the design process, a transmission service framework was developed that to allow the implementation of the flow-based methodology while leaving in place the pre-existing obligations and agreements of the Transmission Owners. This is not a wholesale change in the provision of transmission service, but rather an incremental change. Because the pre-existing rights remain in place the effect on the overall market will be quite modest. A flow-based approach will account for existing commitments when new rights are issued and right trading is enabled.

b. Pre-Existing Rights Undisturbed. Transmission users with pre-existing rights may continue to use their rights as they have in the past. The contracts that establish such rights will continue to define the rights granted and the limitations imposed. The implementation of the Grid West flow-based model will not force any change in pre-existing agreements and obligations. The holders of pre-existing rights will have the option of using Grid West's broader transmission services or continuing to take transmission service as defined by their pre-existing contracts.[12]

---

longer exists. Instead, service availability is determined according to the physical capacity of critical elements or flowgates. Flowgate may be a single line or transformer or a set of parallel facilities that can be treated as a single network constraint. The uncommitted physical capacity of a flowgate is called Available Flowgate Capability (AFC). AFC is not based on ownership but on actual network effects of a transmission reservation. A given injection-withdrawal right will result in use of multiple flowgates; however, the Transmission Customer is not required to manage these details.

[12] See the Tariff Administration White paper for further discussion of pre-existing rights and obligations, rollover, load growth, etc.

3.5 The Transmission Service Framework

The framework for Grid West transmission service has two key aspects: (1) the transmission service structure and (2) the transmission tariff structure.

a. Transmission Service Structure. Grid West will offer a Regional Network Service (RNS), a new suite of services that will allow users to obtain transmission rights to schedule energy across the Grid West network. This service suite includes:
   - Reconfiguration Services.
   - Capacity Expansion Service.
   - Scheduling Services.

b. Qualifying for RNS. As described in early 2004 discussions, a Transmission Customer would qualify for RNS by meeting a System Access Requirement (SAR). As originally conceived, the SAR requirements would be matched to a Transmission Customer's commercial role.

   [Note to readers: In recent discussions of the pricing model for fixed cost recovery, it has become clear that the access fee concept carried over from the RTO West model does not fit the Grid West service model. The SAR was intended to verify that a Transmission Customer would be making an appropriate contribution to recovery of the system's fixed costs (i.e., the Transmission Owners' Revenue Requirements in order to qualify to obtain RNS). Further discussion will be needed to clarify the need for the SAR, and for the qualification standard described below.]

   - Load Serving Entities—Where pre-existing rights cover an entity's full load, the SAR is met. This allows the entity to use RNS to release unused rights for sale or to obtain rights to reach new resources not covered by their pre-existing rights. Load not covered by pre-existing agreements will pay a load based rate to cover such load, thus making RNS available to the entity.
   - Generators—The SAR is met by paying for interconnection with the system. Those with pre-existing rights maintain those rights by continuing to pay the contract charges for the agreements that grant those pre-existing rights. Additional transmission rights can be obtained using RNS.
   - Marketers—Marketers without generation or load must meet the technical and credit standards common to all users of RNS, but have no other intrinsic obligation. If they have pre-existing rights, like generators, they maintain those rights by paying the contract charges for the pre-existing agreements. Additional rights may be obtained using RNS.

c. Recovering Embedded Fixed Costs. When Grid West commences operation, the bulk of the embedded fixed costs of the Transmission Owners, will continue to be met by revenues associated with pre-existing long-term transmission agreements. The charges under these agreements will continue to be paid to the Transmission Owners according to the terms of those agreements. However, because Transmission Owners will no longer issue new transmission rights, the revenues for short-term firm and non-firm service currently received by Transmission Owners will no longer exist. The short-term and non-firm services will be replaced by IWRs purchased using the Reconfiguration Services or obtained from Grid West as available after the end of the day-ahead process.

d. Regional Revenue Requirement Adjustment (R3A). The R3A is a mechanism designed to recover any short-fall in Transmission Owner revenue requirements, with the R3A being paid by those who choose to use RNS.[13]
   - Grid West's sales of AFC through the Reconfiguration Service may recover part (and perhaps most) of the revenue that was previously recovered by the Transmission Owners' sale of non-firm and short-term firm transmission service.
   - The R3A will cover the net cost of offering AFC, i.e., any administrative costs associated uniquely with RNS markets and the residual lost revenue from short-term firm and non-firm sales not recovered by sales of AFC.
   - The R3A could be zero if AFC sales fully offset the lost non-firm and short term revenues and RNS specific costs. Any surplus could be used to reduce other Grid West costs, to reduce the Company Rates of the Transmission Owners, etc.

3.6 The Transmission Tariff Structure

[Note to readers: The following information on tariff structure is based on the Module 1 work done during 2004 Layer 1 design work. While it is the best information currently available, there will be changes in this section as further work is done by the Pricing Work Group and as the tariff structure is revisited in light of their work.]

The above transmission service structure will be implemented through the issuance of a set of tariffs. Pre-existing rights will continue be covered by the transmission tariffs and contracts under which they were established by the Transmission Owners. New services will be covered by either a Grid West Tariff or Transmission Owner Tariffs. The Grid West Tariff[14] will contain general provisions to cover requests for transmission service, planning and capacity expansion, scheduling, the

[13] The rate design for collecting the R3A will be covered by the Pricing Work Group.

recovery of Grid West's costs through a Grid Management Charge, etc. Other provisions may include:

- Coordination and dispute resolution for transmission interconnections. Interconnections will be covered in provisions in Transmission Owner Tariffs.
- The rules for RNS—Qualification (the SAR as applicable), the issuance of IWR (1) through the Capacity Expansion Service for longer than one year, (2) through the Reconfiguration Service for one year or less and (3) during the post day-ahead adjustment period, using residual AFC not otherwise committed, made available on a first-come-first-served basis.
- Company Rates of Transmission Owners – The rates listed will either be the rate listed in a Transmission Owner's Tariff or the rate set by Grid West if a Transmission Owner chooses to have their Company Rate set under the Grid West Tariff.

3.7 Trading Transmission Rights

a. Bilateral Trading of Rights. In Grid West's flow-based injection-withdrawal model, the scheduling rights of a Transmission Customer are defined by Injection Points (IPs), where power enters the Grid West Managed Transmission System (GWMT), and Withdrawal Points (WPs), where power leaves the GWMT. Since Transmission Customers have usage rights that are tied to these points, bilateral transmission right trading is limited to transactions in which there is an identical match between the buyer's and seller's injection and withdrawal points. Since few Transmission Customers will have the matching injection and withdrawal points, bilateral trade will be quite constrained without a centralized mechanism that can consider the system-wide effects of transmission right transactions.

b. The Reconfiguration Concept. To overcome this one-to-one trade limitation, the Grid West proposal includes a Reconfiguration Service (RCS) that allows transmission right holders to sell rights between one set of points and buy rights between a different set of points at the same time. This ability to reconfigure rights is made possible by Grid West's role as the single "gatekeeper" — the only party who can issue new transmission rights in the Grid West Managed Transmission System.

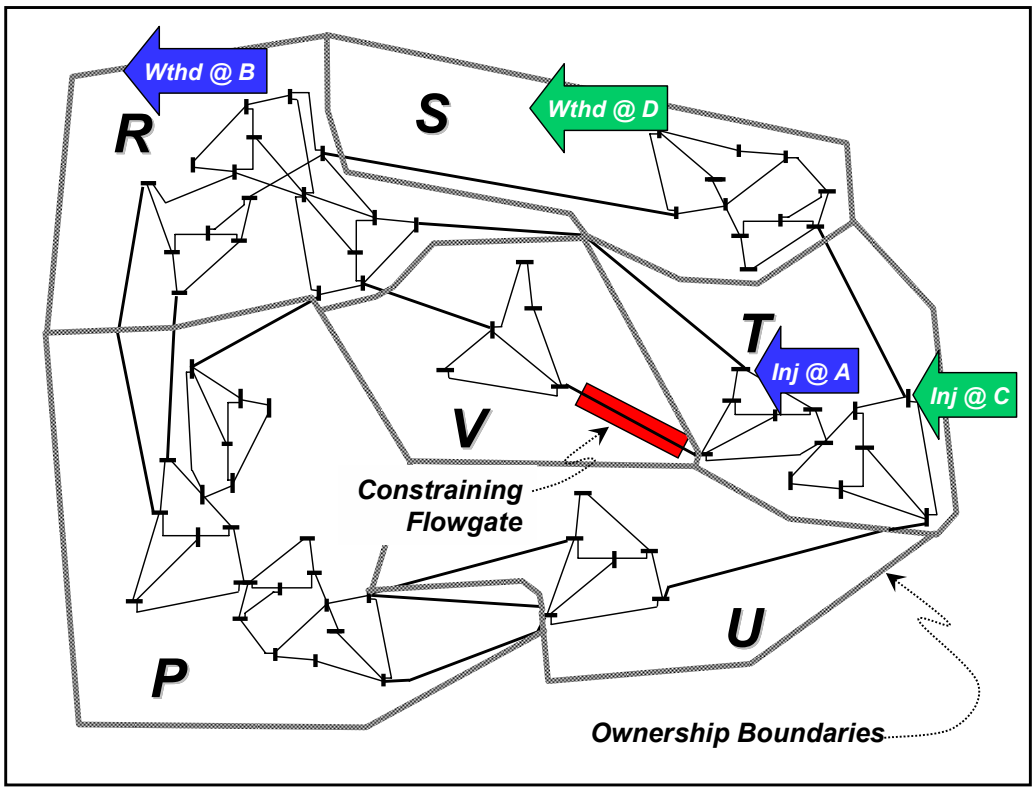
---

[14] The form of the Grid West Tariff and its relationship to Transmission Owner Tariffs has yet to be determined. Some propose that there be a standard set of new Transmission Owner Tariffs with Grid West acting as agent, while others propose a unified Grid West Tariff. At the completion of the Module 1 work, an owner option was suggested, but again the exact form of the tariff was not determined as of the date of this draft.

The Reconfiguration Service is based on a central auction of short-term transmission rights conducted by Grid West.

- IWRs released to the auction increase AFC on specific flowgates.
- Requests made can now be granted by using the combined AFC (both uncommitted capacity and capacity released by right holder offers to sell).
- Trade no longer requires a one-to-one match of injection points and withdrawal points.

Figure 3.6 An example of IWR reconfiguration for an offer of A→B.



c. A Reconfiguration Example. Figure 3.6 shows how IWR reconfiguration works for a simple case of a single IWR release offer and a single bid to buy IWRs.

- *Situation:*
  - Party X holds an IWR from A to B of 100 MW that it is willing to sell next month.
  - Party Y wants to purchase an IWR from C to D for 200 MW that for next month.

- *Without Reconfiguration Service:*
  - Since the points of injection and withdrawal for the A→B right do not match those of the C→D right requested, no direct trade of rights is possible
  - The two IWRs have different effects upon the constraining flowgate that for this example is within the ownership boundaries of V. The Path Utilization Factor (PUF) for an A→B injection-withdrawal pair is 30;%; that is, for a 100 MW schedule there will be an incremental flow increase of 30 MW on the constraining flowgate. The PUF for C→D is 20%.
- *With Reconfiguration Service*:
  - Using the RCS a trade can be affected.
  - Party X offers its 100 MW A→B for release (sale), which makes the AFC on the constraining flowgate 30 MW (PUF_{A-B} x Offer).
  - Party Y bids to buy 200 MW C→D which would require 40 MW of AFC on the constraining flowgate.
  - Y's full request cannot be satisfied, but 30 MW is available, so a 150 MW C→D IWR can be issued. (AFC / PUF_{C-D})
  - Without the trade, the capacity held for X's use would have gone unused, yet there was no way for such a trade to have occurred on a bilateral basis.
  - Note that the MWs for the two IWR are different because of the impact of each IWR on the constraining flowgate. This demonstrates the reason that bilateral trading must be restricted to identical one-to-one exchanges. The trading parties on their own have neither a means of measuring impacts of altered usage nor are they authorized to make changes in the rights issued to them.

d. Practical Implementation of Reconfiguration. In actual practice, many offers to release and bids to buy will be submitted and processed simultaneously. The auction software for reconfiguration trading uses a power flow algorithm that can simultaneously award IWRs while keeping all subscriptions within AFC limits. Existing software is available from vendors which can be modified enable trading of physical, flow-based rights through Grid West. The characteristics of IWRs issued by Grid West, whether from a reconfiguration auction or in connection with long term expansion, will be standardized, with terms of use to be defined by the Grid West tariff. The nature of released (sold) rights of whatever vintage or source will have no impact on the characteristics of an IWR.

e. Addressing Scheduling Flexibility. A day-ahead redispatch feature was included in the Regional Proposal[15] as a Basic Feature of Grid West. The purpose of the day-ahead redispatch was to enable greater use of the transmission system by getting advance scheduling commitments. However, major difficulties were encountered in attempting to design such a day-ahead redispatch:
   - A voluntary day-ahead redispatch is a partial energy market that must be settled against a real-time energy market, but since not all parties participate, the optimization achieved can be undone by parties who retain their pre-existing scheduling flexibility.
   - Measurement and settlement of committed schedules would be difficult because not all of them would be settled in the same balancing market, i.e., some within the CCA and some in non-CCA balancing areas.
   - Finally, it appeared that there were potential gaming problems that would have to be addressed.

f. The Day-Ahead Reconfiguration Service. When day-ahead redispatch was revisited after the reconfiguration service had taken shape, it became clear that much of the desired effect of the day-ahead redispatch (i.e. commitments to a specific generation plan) could be accomplished by allowing parties to release a portion of their generation scheduling flexibility through the Day-Ahead Reconfiguration Service (DA-RCS).
   - If transmission right holders[16] give up their options for scheduling flexibility in the DA-RCS there is a reduction in the "headspace"[17] that must be set aside to meet obligations for pre-existing rights.
   - This reduced headspace becomes AFC that can be sold as IWRs.
   - The typical day for pre-scheduling fits the general pattern in use today:
     - Trades for the next day occur very early in the morning.
     - Requests are made for transmission from various transmission providers.
     - Pre-schedules are submitted.

---

[15] "Narrative Description of RRG Platform Group Regional Proposal", December 24, 2003, pp. 7-8, http://gridwest.org/Doc/FinalNarrative_RegionalProposal_Dec242003.pdf. The Regional Proposal described an Independent Entity (IE) that has since been given the name Grid West.

[16] These flexible scheduling rights include those used for native load service by Transmission Owner and the largest potential source of releases of existing scheduling flexibility.

[17] Headspace is a term used to describe the capacity set aside prior to an RCS auction to preserve pre-existing rights, including the scheduling flexibility (or optionality) of transmission right holders to change their schedules after the close of the day-ahead scheduling process.

By enhancing the DA-RCS to handle releases of scheduling flexibility, the complications of the day-ahead redispatch service can be avoided while achieving a good deal of the objectives, namely making more capacity available through voluntary offers to restrict changes in generation patterns for the following day. The enhanced DA-RCS allows individual Transmission Customers to find transmission through a central auction conducted by Grid West, where AFC is made available by releases of scheduling flexibility along with offers of IWRs and AFC.

3.8 Rights Data Management

Providing both new transmission rights and honoring pre-existing rights will require Grid West to have an accurate record of all transmission right obligations for the GMWT. The process of Rights Data Management will meets this need and will be made up of four processes.

a. Physical Rights Inventorying. Grid West will compile a data base that records all obligations for the GWMT. This will include IWR issued by Grid West and the Transmission Owner rights obligations associated with pre-existing transmission rights. For the inventory of Transmission Owner obligations, Grid West will work directly with the Transmission Owners to determine and inventory their aggregate obligations. This inventory will be used to support: (1) the calculation of AFC, (2) the validation of schedules and (3) the operation of the Reconfiguration Service.

b. ETR Certification. If a Transmission Customer wants to schedule directly with Grid West or offer its scheduling flexibility into the Day-Ahead Reconfiguration Service, it will request Existing Transmission Right (ETR) Certification from Grid West. Certification will produce a set of Certified Existing Transmission Rights (CETRs). Each CETR will include a set of scheduling points and their associated scheduling flexibility.

c. IWR Translation Query: If a Transmission Customer wishes to release IWRs into the Reconfiguration Service, it will submit an IWR Translation Query to Grid West. The Transmission Customer will indicate what portion of its CETR it wants to have identified as potential IWRs. In the translation process, Grid West will use a flow-based model to calculate the IWR value available from the CETR for a specified time period and indicate the value of any remaining transmission rights not used to enable the creation of IWRs. Information provided in response to a query does not commit the Transmission Customer to offer IWRs. The customer may continue to use its CETR as before, or it may make a release into a specific Reconfiguration auction. If offers are not taken, the Transmission Customer's rights revert to its CETR.

d. Bilateral Trade Registration. When bilateral trade of IWRs occurs in the secondary market Grid West will provide a registration service that permits the purchaser to schedule against the IWR, in effect a title transfer.

4.0 CONTROL AREA CONSOLIDATION

4.1 Voluntary Control Area Consolidation

The Regional Proposal[18] noted that some of the Transmission Owners expected to be within the Grid West footprint were discussing the possibility of consolidating their individual control areas. Grid West would provide the services needed by the consolidating parties to operate the Consolidated Control Area (CCA). The motivations of those considering participating in the CCA include increased reliability and operational efficiencies.

a. Reliability. Consolidation of control areas by those Grid West Transmission Owners expected to voluntarily participate will put certain control functions for a substantial portion of the regional grid under a single operator who will have authority to take appropriate actions when needed. The need for wider visibility outside of individual control areas has been identified as a means of improving the capability of operators to make proactive adjustments to protect system reliability.[19] Consolidation of control areas with an associated investment in infrastructure will be necessary to obtain this benefit.

b. Operational Efficiencies. Consolidation is expected to reduce the total requirement for regulating reserves and balancing energy, due to diversity among the loads and generation within the CCA. Furthermore, the establishment of a market for providing the Interconnected Operations Services (IOS)[20] necessary for operating the CCA is expected to reduce the cost of ancillary services.

---

[18] "Narrative Description of RRG Platform Group Regional Proposal", December 24, 2003, pp. 11-12, http://gridwest.org/Doc/FinalNarrative_RegionalProposal_Dec242003.pdf.

[19] "A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities… Improved visibility of the status of the grid beyond an operator's own area of control would aid the operator in making adjustments in its operations to mitigate potential problems. The expanded view advocated above would also enable facilities to be more proactive in operations and contingency planning." Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force, April 2004 pp. 159-160.

[20] IOS are generation services that, when combined with transmission services create ancillary services.

c. Transmission Utilization. The CCA will be able to make full use of transmission capacity within its boundaries in real-time to follow load, provide regulation and imbalance energy requirements, respond to contingencies, etc., without regard to facility ownership.

d. Voluntary Participation. In keeping with the voluntary nature of control area consolidation, each existing control area operator will make its own decision about whether or not to join the CCA based on it is own assessment of the benefits to be obtained.

4.2 Grid West as a Control Area Operator

Grid West will operate a Consolidated Control Area (CCA) for those who voluntarily choose to consolidate to obtain the benefits described in Section 4.1. The IOS needed by Grid West for CCA operation are:

- Capacity arranged day-ahead to obtain contingency reserve and regulating reserve needed for system operations.
- Energy offers (i.e., incremental and decremental offers) for balancing load, generation and interchange in real-time.

Grid West will obtain IOS by operating markets since it is neither an owner of, nor in control of, any of the assets needed to provide these services. These markets will provide price transparency, which will benefit both buyers and sellers and assist in market monitoring efforts.

- A Reserves Market will be used to obtain capacity related IOS.
- A Real-Time Balancing Service will be a market using voluntarily offered real-time energy options for system balancing requirements.

Grid West will encourage all market participants to make offers to provide these IOS to the CCA. Their participation will provide a wider range of options with lower production costs and greater efficiency. Service costs for CCA operation will be separated from other Grid West activities that apply to the entire Grid West Managed Transmission System.

5.0 THE WHITE PAPERS AND REFERENCE PAPERS

As noted above, TSLG divided its assignment into five work modules. Module 5, which will produce a Grid West cost estimate, is not covered by the white papers, but will be produced separately. This section of the Overview paper will describe the white papers that cover TSLG's work on the other four modules and will compliment Sections 2 and 3

that described the concepts involved in moving to a flow-based, physical rights model of transmission service. Descriptions of each paper are provided in Appendix A.

5.1 Module 1 – The Transmission Service White Papers

Two white papers will cover Grid West's provision of transmission service: (1) Planning and Capacity Expansion and (2) Tariff Administration. Neither of these papers is currently available. In the Regional Proposal, it was anticipated that Grid West's planning process would be adapted from the RTO West proposal. RRG discussions on planning are still unresolved, so work on the planning paper was put on hold by TSLG. Early work on the tariff structure is described below. As the Pricing Work Group completes its work, the tariff issues will be revisited in order to produce the tariff paper.

5.2 Module 2 – The Rights Administration White Papers

The papers on rights administration cover the key features of the flow-based, physical rights model for transmission service. These four papers are: (1) Transmission Rights Reconfiguration Service, (2) Day-Ahead Redispatch, (3) Bilateral Trading and (4) Rights Data Management. The Reconfiguration Service paper is the heart of this work module. It provides narrative discussion of the mechanism to be use to implement the reconfiguration services. It also provides extensive examples in its appendices using a three-bus transmission model to explain the reconfiguration process step by step.

5.3 Module 3a – The Scheduling White Papers

Module 3 describes that systems and operational process needed to implement the system-wide view of the transmission system and the flow-based model of transmission service. Module 3 was broken into three parts, with Module 3a covering issues related to scheduling use of the transmission system in four papers: (1) Market Information System, (2) Outage Coordination, (3) Scheduling and Schedule Adjustment and (4) Transmission Losses. The Market Information System will meet OASIS requirements, provide website access to public data and provide a private portal for the exchange of market related information (offers, bids, awards, etc.). Grid West will take a lead role in regional outage coordination in its role as a Transmission Authority for the GWMT. The day-ahead scheduling process is described in the scheduling paper using illustrative timelines, and the process for obtaining transmission service after the close of the day-ahead process is also described. The loss provisions of pre-existing rights will remain unchanged with loss schedules going to the original transmission service provider under the terms of the applicable agreements. The loss paper describes the mechanism to be used to determine loss responsibility when using IWRs issues by Grid West.

5.4 Module 3b – The Operations White Papers

Module 3b addresses operational activities of Grid West. Three of the papers cover general operational issues: (1) NERC Reliability Functional Model, (2) Real-Time

Monitoring and (3) Emergency Operations. The functional model paper discusses roles, authorities and responsibilities for system operations as provided in the NERC Reliability Functional Model, and the paper explains how these roles will be met when Grid West is operational. As a Transmission Authority, Grid West will be responsible for real-time monitoring and for providing direction in emergency conditions. The fourth paper in this module covers the Real-Time Balancing Service, used by Grid West in its role as the Balancing Authority for the CCA.

5.5 Module 3c – The Settlements White Papers

The Module 3c papers are: (1) CCA Settlement Metering, (2) Settlements and Invoicing and (3) Dispute Resolution Process. These are essential administrative services. The dispute resolution process covers billing, rights certification and IWR translation query disputes. The settlement process for Grid West markets is illustrated in the settlement and invoicing papers. The metering paper covers the metering needed by Grid West for settling the Real-Time Balancing Service used to meet CCA needs. Most metering needs can be met using existing equipment.

5.6 Module 4 – The Ancillary Services White Papers

The three papers in Module 4 are focused on the reserve aspect of ancillary services – regulating and contingency reserves: (1) CCA Reserve Market, (2) CCA Reserve Deployment and (3) CCA Participation in Reserve Sharing. Within the CCA, Grid West will operate a market to obtain needed reserves and will deploy them in real-time to meet the needs of the CCA. The Grid West CCA will be a participant in the Northwest Power Pool's Pro-Rata Reserve Sharing program for contingency reserves.

5.7 The Reference Papers

The White Papers investigate specific design features in some depth. TSLG recognized the need for more general treatment of some issues that reach across more than one subject area. The four Reference Papers address this need. One reference paper, Congestion Management, is a synopsis that examines Grid West congestion management features that are woven into the market and operational design by looking at how the pieces fit together to make a consistent whole. The other three reference papers look at concerns common to many of the white papers: (1) Auction Pricing, (2) Commercial Model and (3) Grid West Seams Issues. The auction pricing paper explains why a market clearing price approach was selected for all Grid West markets. The seams paper discusses issues that will need to be addressed in dealing with neighboring systems. The commercial model paper is not yet available, but will be completed prior to the start of Layer 3 work. The purpose of the commercial model paper is to serve as a bridge between the White Papers of

Layer 2 and the Protocols to be developed in of Layer 3.. The Commercial Model paper will define the roles of participants and identify the relationships between entities. This information will be used to establish procedures for the registration of arties to participate in markets, perform given functions, , etc..

APPENDIX A: LIST OF TSLG LAYER 2 DESIGN PAPERS

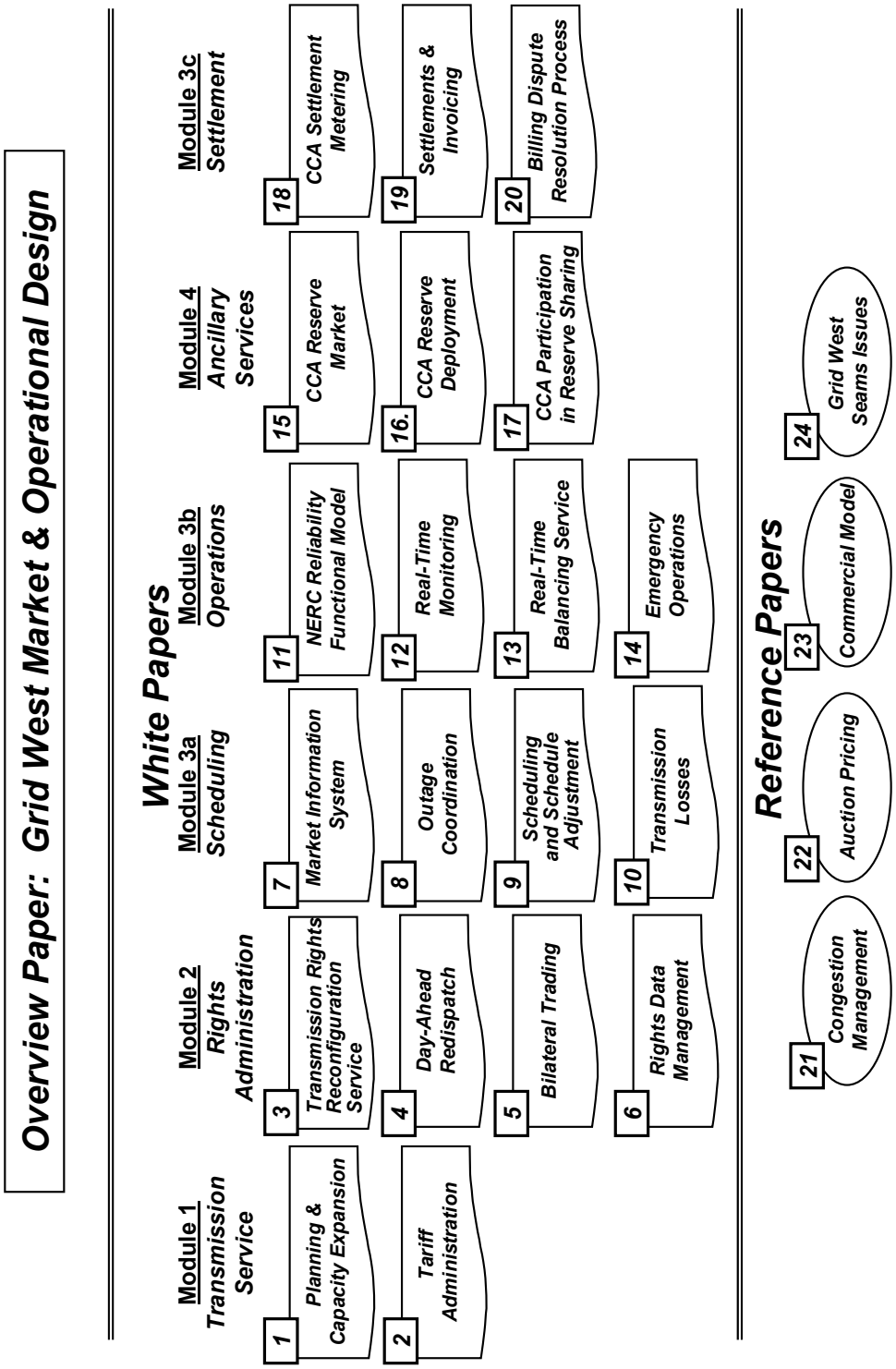


Figure A.1 Chart of TSLG paper describing the conceptual framework of Grid West's market and operational design. Paper numbers are keyed to the list of paper summaries provided below.

This appendix contains a complete list of the TSLG papers prepared in the Layer 2 effort to describe the conceptual framework for Grid West's market and operational design. The titles are shown in Figure A.1, organized by work module. The paper numbers shown in Figure A.1 correspond to the numbering of the list of summaries provided below. The white papers listed in Section A.1 cover individual design features in some detail. Unlike the white papers, the reference papers listed in Section A.2 look across all design elements from the perspective of a single issue and consider how that issue is addressed or should be addressed when the design is considered as a whole.

A.1 List of White Papers

1. ***Planning & Capacity Expansion*** – *(Not completed)* Describes the regional planning process to be facilitated by Grid West and the mechanisms for capacity expansion. Grid West will develop an open transmission planning process that examines expansion needs from a single system perspective, tests for transmission adequacy and considers non-transmission alternatives to meeting system needs. The capacity expansion service will deal with requests for long-term service requests (greater than one year). If capacity is not available to meet the request, the capacity expansion service enables market driven transmission projects to meet requests. It also provides for expansion backstops for maintaining existing transfer capability and meeting transmission adequacy standards.

2. ***Tariff Administration*** – *(Not completed)* Describes the provision of transmission service through the Grid West Tariff and the related Transmission Owner tariffs. It describes the roles of Grid West, the Transmission Owners and the Transmission Customers, and it provides discussion of issues related to pre-existing contracts, such as load growth, contract termination or roll-over, etc.

3. ***Transmission Rights Reconfiguration –*** Describes the implementation of the reconfiguration service: mechanisms for determining pre-existing obligations, auction rules and pricing of IWRs sold and purchased. A series of auctions addresses different time periods:
   - Annual for monthly on-peak and off-peak IWRs.
   - Monthly for monthly on-peak and off-peak IWRs for the balance of the annual period of the auction cycles.
   - Intra-monthly for daily on-peak and off-peak IWRs for the balance of a month.
   - Day-Ahead for hourly IWRs for the next day. The Day-Ahead Reconfiguration Service (DA-RCS) will have an enhanced feature to enable trading of scheduling flexibility options.

4. ***Day-Ahead Redispatch*** – Describes the day-ahead redispatch service envisioned in the original Regional Proposal and explains how the objectives of day-ahead redispatch will be met by enhancements to the Day-Ahead Reconfiguration Service without encountering the difficulties of reconciling day-ahead bids with real-time imbalances that were discovered during TSLG's Layer 1 work.

5. ***Bilateral Trading*** – Evaluates the effects of Grid West proposed services and functions on current bilateral trading practices within the Grid West Managed Transmission System.

6. ***Rights Data Management*** – Describes the processes and functions used by Grid West to manage transmission rights data, including:
   - Inventorying of the injection and withdrawal commitments associated with pre-existing agreements and obligationsl
   - Certification of existing rights to enable the release of scheduling flexibility options into the day-ahead reconfiguration auction.
   - Translation of certified existing transmission rights into IWRs, either in whole or in part, prior to release into reconfiguration auctions.

7. ***Market Information System*** – Explains data and functional features of an information system that provides OASIS services, public information through a general website, and a private portal for scheduling, submission of bids and offers in markets, transmission of market results, settlement statements, etc.

8. ***Outage Coordination*** – Describes the proposed process Grid West will use to take a leading role in coordinating transmission outages. Generation outage information will be requested by Grid West to aid in reliability determinations, but coordination will not generally be performed and such data will not be made public.

9. ***Scheduling & Schedule Adjustments*** – Describes process and data needed by Grid West and its participants to schedule transactions including tagging, timing, etc. The paper describes the proposed process for adjusting schedules and checkout procedures required to ensure accurate interchange schedules and Net Scheduled Interchange between Balancing Authorities in or adjacent to the GWMT.

10. ***Transmission Losses –*** Confirms no change in the treatment of losses for pre-existing agreements and describes a proposed methodology to be used for calculation of loss responsibilities for schedules using IWRs.

11. ***NERC Reliability Functional Model –*** Describes proposed roles and responsibilities for Grid West and participants to meet the requirements of the NERC reliability functional model.

12. ***Real-Time Monitoring*** – Describes the proposed real-time monitoring process including the data needed to support both reliability and market functions.

13. ***Real-Time Balancing Service –*** Describes the operation of the balancing service used to obtain real-time Interconnected Operations Services for the CCA, while accounting for the nature and types of energy offers and selection of resources. It also describes the dispatch processes for resources selected by Grid West for the Real-Time Balancing Service including dispatch granularity, dispatch frequency, control signals process and routing, etc.

14. ***Emergency Operations*** – Describes the proposed emergency operations roles and responsibilities of Grid West for the GWMT as a Transmission Authority. The topics covered include emergency conditions, operating limits, NERC standards, the NWPP Energy Emergency Plan, and Grid West's operational responsibilities.

15. ***CCA Reserve Market*** – Describes the proposed operation of the reserve market used by Grid West to cost-effectively obtain contingency and regulating reserves for the CCA. The topics covered include the reserve products, reserve requirements, market timing, market operation, etc.

16. ***CCA Reserve Deployment*** – Describes the procedures to be used in real-time to deploy the reserves of the CCA that were obtained through the Reserve Market.

17. ***CCA Participation in Reserve Sharing –*** Describes the current Northwest Power Pool reserve sharing agreement and discusses the impact of the Pro Rata Reserve Sharing program on the operation of the CCA.

18. ***CCA Settlement Metering*** – Describes the process associated with the collection and management of CCA settlement meter data including what data is required and who is responsible for providing it.

19. ***Settlement & Invoicing*** – Describes the proposed process for market settlement and invoicing. The topics covered include settlement statements, periodic invoicing, payment issues, and an illustrative timeline for settlement and invoicing.

20. ***Dispute Resolution*** – Describes the proposed dispute resolution process for resolving settlement, billing disputes, certification and translation disputes.

A.2 List of Reference Papers

21. ***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.

22. ***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.

23. ***Commercial Model*** – *(Not yet completed)* Describes the Grid West commercial model, identifying the entities and assets that will use Grid West service and information that must be collected through a registration process, including the relationships among the entities and their relationship to Grid West.

24. ***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.

Definitions	***Acronyms***
Adjustment Period – The period that begins at the end of Day-Ahead and ends at the cut-off for schedule changes prior to an Operating-Hour.	
Alternative Dispute Resolution – As described in the Article XIII of the Grid West Developmental and Operational Bylaws, Transmission Agreements, the Grid West tariff, etc.	**ADR**
Ancillary Services – Services associated with the provision of transmission service which may be provided by a transmission provider to a transmission customer or in some cases self-supplied; these include regulation and frequency response, load following, spinning reserve, non-spinning reserve, imbalance energy, voltage support, black start and scheduling and dispatch.	**A/S**
Annual Reconfiguration Service – An auction of IWRs conducted two months prior to the beginning of each auction-cycle-year for the trading of on-peak and off-peak rights for each of twelve months in the next auction cycle year.	**A-RCS**
Area Control Error – The difference between Scheduled and Actual Interchange measure by a Control Area (or a Balancing Authority).	**ACE**
Automatic Generation Control – Dynamic control of generating resources during the operating-hour (real-time) to maintain the balance of generation and resources, maintain system frequency, etc.	**AGC**
Available Flowgate Capability – Uncommitted capacity on a flowgate (a line or set of lines with a combined rating, i.e. a "rated system path"). The committed capacity is the sum of the flow components calculated using power utilization factors (also called power distribution factors or generation shift factors) applied to committed injection-withdrawal rights.	**AFC**
Available Transmission Capability – The term used in OATTs to describe uncommitted transmission capacity available for sale on a transmission path. [1]	**ATC**

[1] AFC is used in conjunction with the Regional Proposal to more clearly communicate the impact of a given IWR upon a given facility or set of facilities that may constrain the issuance of additional IWRs.

Definitions	***Acronyms***
Balancing Authority – An entity that maintains load-resource balance with an area defined by a metered boundary.	**BA**
Bid – The submission of a request to purchase at or below a given price.	
Bilateral Trade Registration – Registration of IWR trades in the secondary market.	
California Independent System Operator – An RTO covering the greater part of the state of California.	**CAISO**
Capacity Expansion Service – A service that provides a means for acquiring Injection-Withdrawal Rights that are not available using existing system capacity and for which construction or expansion is necessary.	**CES**
Certain Distribution Facilities – Dual-function facilities that: (1) are used primarily to provide retail load service, with a secondary purpose of providing, and supporting the provision of, wholesale transmission services; and (2) have been classified as distribution facilities pursuant to State or federal order. Despite such classification, these facilities have an effect on Grid West's ability to manage capacity within the Grid West Managed Transmission Facilities. The Transmission Owners will retain ultimate authority for all local distribution planning and expansion on these facilities, but Grid West will have planning and expansion authority on these facilities for transmission adequacy and congestion management purposes. These facilities will be listed in an exhibit to the Transmission Agreement executed by each Transmission Owner.	
Certified Existing Transmission Right – An existing transmission right that has been certified at the request of the transmission right holder.	**CETR**
Consolidated Control Area – A voluntary consolidation of electric power systems bounded by interconnection (tie-line) metering and telemetry. It controls generation to maintain its interchange schedule with other control areas and contributes to frequency regulation of the interconnection, with operational services provided by Grid West.	**CCA**

Definitions	***Acronyms***
Control Area Operator – The operator of an electric power system bounded by interconnection (tie-line) metering and telemetry. It controls generation to maintain its interchange schedule with other control areas, to maintain instantaneous load/resource balance within its system, and contributes to frequency regulation of the interconnection.	**CAO**
Control Performance Standard – One of two quantitative measures (CPS1 or CPS2) established by NERC to monitor the real-time operations of balancing authorities (control areas).	**CP1** or **CPS2**
Day-Ahead – A period beginning at 5:00 am protocols to be developed) of the day preceding a given operating day and ending at 5:00 pm of the same day. (Times given are for illustrative purposes and may change the detailed protocols are later developed.)	**DA**
Day-Ahead Reconfiguration Service – An auction of IWRs conducted prior to each Day-Ahead scheduling period to offer on and off-peak rights for each Operating Hour covered by the upcoming Day-Ahead scheduling period.	**DA-RCS**
Dynamic Schedule – A type of dynamic transfer where a telemetered reading or value that is updated in real-time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes.	
Dynamic Transfer – A method by which the control response to loads or generation is moved, on a real-time basis, from the Control Area where they physically reside (the native Control Area) to a second Control Area in which they do not physically reside (the attaining Control Area) on a real-time basis. (See Dynamic Schedule and Pseudo-Tie for description of methods.)	
Electric Reliability Council of Texas – An RTO covering the Texas Interconnection.	**ERCOT**
E-Tag – The collection of information in an electronic request for an energy schedule and subsequent responses utilized in the electronic Transaction Information System (TIS) implemented by NERC.	

Definitions	***Acronyms***
Existing Scheduling Flexibility – The option of a Transmission Customer (arising from either pre-existing agreements or obligations) to select Injection Points from a specified set of points, subject to maximum amounts at any given point and an overall limitation on the combined injections.	**ESF**
Existing Transmission Rights – Rights arising from pre-existing agreements and obligations of the Transmission Owners.	**ETR**
Export – Energy scheduled to a control area outside the Grid West Footprint.	
Federal Columbia River Power System – For further information see http://www.bpa.gov/power/pgf/hydrPNW.shtml	**FCRPS**
Federal Energy Regulatory Commission	**FERC**
Financial Transmission Right	**FTR**
Formula Power Transmission Service – A historic type of transmission service (pre-Order 888) provided by Bonneville Power Administration that is based on the mileage between specified PODs and PORs.	**FPT**
General Transfer Agreement – A agreement entered into by Bonneville Power Administration with a third-party Transmission Provider in lieu of federal transmission construction in order to provide transmission service to Bonneville's preference customers.	**GTA**
Geographic Area – The portions of the provinces of Alberta and British Columbia and the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming that are electrically within the Western Interconnection, together with any additional geographic territory within the state of California that is encompassed by the control areas of the Bonneville Power Administration, PacifiCorp, and Sierra Pacific Power Company.	
Grid Management Charge – A fee charged to recover the general operating costs of Grid West.	**GMC**

Definitions	***Acronyms***
Grid West – A member based, non-stock, not-for-profit regional independent transmission organization. Grid West supervises the collective transmission facilities of its service area and is charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, network reliability (in coordination with PNSC), and administration of the markets. Transmission owning members authorize Grid West to exercise functional control over their transmission systems. Market Participants and Transmission Customers provide electric generation or serve load to end-use customers, respectively, over the Grid West operated transmission facilities in the Grid West service area.	**GW**
Grid West Managed Transmission System – The transmission facilities over which Transmission Owners have granted Grid West authority to manage transmission capacity requests and usage by execution of a Transmission Agreement.	**GWMT**
Grid West Participant – A Transmission Customer or Market Participant or other party who makes offers to sell or bids to buy in the RCS, Balancing Service or Reserve Markets operated by Grid West.	
Grid West Tariff – The tariff to be issued by Grid West covering services it provided (e.g. Regional Network Service) and covering the collection of embedded costs for those Transmission Owners who opt not to include their company rate in their TO Tariff.	
Grid West Transmission Service Commencement Date – The date when Grid West becomes operation by beginning to accept schedules for service and issue Injection-Withdrawal Rights for use of the Grid West Managed Transmission System.	
Inadvertent Interchange – The difference between the net actual interchange and the net scheduled interchange flow, measured hourly. It provides an indication of the imbalance between the power commitments and power supplied by a control area. It may be caused by: (1) bias response to frequency and time deviations occurring on the interconnected systems, (2) instrument and control errors, (3) inability of system to maintain schedule, or (4) tie-line schedule changes.	

Definitions	***Acronyms***
Inc/Dec (Incremental and Decremental) Offers– Offers submitted in either a Day-Ahead Redispatch Market or a Real-Time Balancing Service to indicate willingness to increase (inc) or decrease (dec) power injected into the system for a given offer price. A load may make an Inc Offer to reduce load an thereby make in incremental increase in power available to serve other loads.	
Independent Entity – A term used in the Regional Proposal to describe what has subsequently been named Grid West.	**IE**
Independent Market Monitor – An entity that reports studies, findings and recommendations, based on work performed under its Market Monitoring Plan for the markets it is charged to study, directly to the Federal Energy Regulatory Commission, the U.S. Department of Justice, state and provincial regulatory and enforcement entities and to the independent governing board of Grid West.	**IMM**
Independent Power Producer	**IPP**
Independent System Operator	**ISO**
Injection Point – A point at which energy enters the Grid West transmission system used to identify the "from" location of an IWR.	**IP**
Injection-Withdrawal Right – The right to submit a day-ahead Injection-Withdrawal Schedule that is measured in 1 MW increments.	**IWR**
Injection-Withdrawal Schedule – A schedule of balanced energy injections and withdrawals at specified Point(s) of Injection and Point(s) of Withdrawal on the Grid West Managed Transmission System.	**IWS**
Integrated Resource Transmission Service – A historic type of transmission service (pre-Order 888) provided by Bonneville Power Administration that provides for integration of power from multiple resources to a defined set of delivery points.	**IR**
Intended Retained Right – The portion of Existing Scheduling Flexibility remaining after and offer to release scheduling flexibility has been accepted in the DA-RCS.	**IRR**

Definitions	***Acronyms***
Interchange Scheduling and Accounting Subcommittee – A subcommittee of the WECC Operating Committee.	**ISAS**
Interconnected Operations Services – Services obtained from generators or loads which are used by a Transmission Provider to supply Ancillary Services, these included regulation and frequency response, load following up, load following down, spinning reserve, non-spinning reserve, replacement reserve, congestion redispatch, supplemental energy, voltage support and black start.	**IOS**
Interconnection – The connection of loads and generation to a provider's principal network sufficient to serve load and deliver output.	
Intra-Month Reconfiguration Service – An auction of IWRs conducted two days prior to each operating day, for the trading of on-peak and off-peak rights for that operating day and for the remaining operating days in the balance of the calendar month.	**I-RCS**
Interconnection Reliability Authority – An entity that ensures the operating reliability of the interconnected bulk electric transmission systems within an Interconnection Reliability Authority Area, such as the PNSC. The IRA has the responsibility and authority to direct and coordinate all operating reliability functions within its area to maintain the reliability of the Interconnection.	**IRA**
IWR Timeline – The period for which a IWR is applicable, e.g., and IWR with a timeline of "July 2006 Monthly Peak" allows the holder to schedule use between 6 am and 10 pm on Monday-Saturday during July 2006.	
IWR Translation – Translation of a Transmission Customer's CETRs into IWRs for potential trade in RCS that occurs, based on specific and voluntary request by the Transmission Customer.	

Definitions	***Acronyms***
IWR Type – General categories of IWRs offered in the RCS: o Monthly Peak (6 am to 10 pm Monday-Saturday) o Monthly Off-Peak (10 pm to 6 am, Monday-Saturday and all hours on Sundays and holidays) o Daily Peak (6 am to 10 pm Monday-Saturday) o Daily Off Peak (10 pm to 6am Monday-Saturday and all hours on Sundays and holidays) o Hourly (every hour of the next operating day)	
IWR-Day – The calendar day during which IWRs obtained in the I-RCS are effective.	
IWR-Month – The calendar month during which IWRS obtained in the M-RCS are effective.	
IWR-Year – The twelve month period during which IWRs obtained in the A-RCS are effective.[2]	
Load Serving Entity – A Grid West Market Participant , including a municipal electric system an electric cooperative, an aggregator, and a tribal agency, authorized by law, regulatory authorization or requirement, agreement, or contractual obligation to supply electrical power, to retail Customers located within Grid West's Service Area. Or an entity that uses transmission in interstate commerce to provide power to a load, whether a distribution utility or commercial customer that has retail access rights. It includes an entity that takes service directly from a supplier to serve its own Load.	**LSE**
Locational Clearing Price – The nodal prices derived from an RCS auction. Differences in LCPs provide the value of and IWR between and Injection Point and Withdrawal Point.	**LCP**
Locational Imbalance Prices – Clearing prices used to settle energy transactions in the Real-Time Balancing Service.	**LIP**

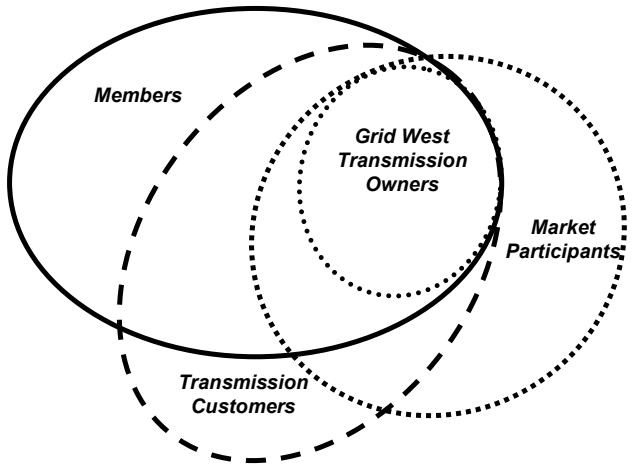
[2] Depending upon the final choice of period made, the IWR-Year may be either a calendar-year (January to December) or a Northwest water-year (September to August).

Definitions	***Acronyms***
Long Term Planning – Capacity expansion and reliability planning for transmission facilities within the Grid West Managed Transmission System for the period one year more or more in the future.	
Loss Schedule – A schedule providing losses in-kind that is equal to the losses assigned to a Transmission Customer's composite injection-withdrawal schedule multiplied by an appropriate loss factor.	
Loss Factor – A number which when multiplied by a schedule quantity produces the losses attributable to that transaction.	**LF**
Market Information System – An electronic interface between Grid West and Grid West Participants that will include OASIS functions and an electronic portal for scheduling, submissions to markets, posting of market results, etc.	**MIS**

Definitions **Acronyms**

Market Participant – An entity that executes an enabling agreement with Grid West so that it may make offers to sell or bids to buy services in any market administered by Grid West, i.e., Reconfiguration Service, Redispatch Service and markets used to obtain Interconnected Operation Services for operation of a Consolidated Control Area, initially a Reserve Market and a Real-Time Balancing Service. (Figure 1 shows the relationship between Market Participants, Members, Transmission Customers and Transmission Owners.) **MP**

Figure 1
Relationship Diagram



Member – An individual or an entity that has chosen to become a member of the Grid West corporation under the terms of its bylaws, which confer rights and impose obligations on those who choose to become members, in particular the right to participate in member voting processes. Members vote (by class) to choose the Member Representative Committee (MRC). The MRC in turn has the power to elect and remove Trustees. (Figure 1 shows the relationship between Market Participants, Members, Transmission Customers and Transmission Owners.)

Definitions	***Acronyms***
Member Representative Committee – A committee of 30 persons elected by Grid West member classes which as described in the Operational Bylaws: elects the Grid West Board of Trustees, elects members to the Arbitration Committee, provides consultation to the Board on the Special Issues List and may initiate a management audit of Grid West.	**MRC**
Midwest Independent System Operator – An RTO covering parts of the ECAR, MAPP and MAIN reliability councils of NERC.	**MISO**
Minimum Operating Reliability Criteria – A standard established by the WECC that governs regulation performance, operating reserves and other reliability standards.	**MORC**
Monthly Reconfiguration Service – An auction of IWRs conducted the week prior to each calendar month, for the trading of on-peak and off-peak rights for each month in the balance of the auction cycle year.	**M-RCS**
Most Significant Single Contingency – The individual event within a reserve sharing pool that has the largest impact on the ability of the pool to meet load, usually the loss of the pool's largest generator.	**MSSC**
Net Scheduled Interchange – The quantity in MWs a Balancing Area is importing (if negative) or exporting (if positive) from within its metered boundary.	**NSI**
Network Transmission Service – A form of transmission service offered under Open Access Transmission Tariffs that provides for the integration of a set of identified resources to an identified set of loads.	**NT**
North American Electric Reliability Council – For more information see http://www.nerc.com/	**NERC**
Northwest Power Pool – A voluntary organization that serves as a forum in the electrical industry for reliability and operational adequacy issues in the Pacific Northwest.	**NWPP**
Offer – A request to sell at or above a given price.	
Open Access Same-time Information System – An transmission services information system required under OATTs.	**OASIS**

Definitions	Acronyms
Open Access Transmission Tariff – Tariffs issued that are compliant with Order Nos. 888 and 889 of the FERC.	**OATT**
Operating Hour – The period time during which a Balancing Authority (or Control Area) actively matches load and generation to meet the performance criteria of NERC.	**OH**
Operating Transfer Capability – TTC adjusted for based on operational considerations and limitations.	**OTC**
Pacific Northwest Security Coordinator – A freestanding nonprofit corporation that is the current Reliability Coordinator for the Pacific Northwest and that funded through a reliability coordination funding agreement with WECC.	**PNSC**
Path Utilization Factors – The proportion of the power injected at a specified point and withdrawn from another specified point that will flow on a given flowgate in the transmission system. PUFs are also been called power distribution factors and generation shift factors. Transmission users can use PUFs to estimate the effect a request may have on posted flowgate AFC prior to RCS auctions.	**PUF**
PJM RTO – An RTO initially covering the PJM Interconnection (Pennsylvania, Maryland and New Jersey) that is currently incorporating parts of West Virginia, Virginia, Ohio, Indiana and Illinois within its operating footprint.	**PJM**
Point of Delivery – The point defined in existing transmission service agreements where energy is delivered to the customer by the transmission provider. PODs may be located on facilities of a Transmission Owner, which are beyond the boundary of the Grid West Managed Transmission System.	**POD**
Point of Interconnection (or Interchange)	**POI**
Point of Receipt – The point defined in existing transmission service agreements where energy is received by the transmission provider from the transmission customer. PORs may be located on facilities of a Transmission Owner, which are beyond the boundary of the Grid West Managed Transmission System.	**POR**

Definitions	***Acronyms***
Point-to-point Transmission Service – Transmission service from specified POR(s) to specified POD(s), as defined in Open Access Transmission Tariffs.	**PTP**
Pre-Day-Ahead – The time period before the commencement of the Day-Ahead scheduling processes.	
Pre-schedule – Schedules submitted during Day-Ahead processes.	
Provider of Last Resort – The requirement imposed in OATT tariffs for the transmission provider to supply ancillary services if the transmission customer chooses not to self-supply or acquire from a third party.	**POLR**
Pseudo-Tie – A type of dynamic transfer where a telemetered reading or value is updated in real-time and used as a tie -line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.	
Purchasing-Selling Entity – An entity that purchases sells energy or capacity and reserves transmission services. A PSE is generally responsible for originating a interchange schedule tag.	**PSE**
Real-Time – The Operating-Hour.	**RT**
Real-Time Balancing Service – A market service administered by Grid West to obtain at energy used to meet is real-time balancing obligations of the CCA. This market uses an optimized dispatch algorithm based on inc/dec offers from both inside and outside the CCA. If there are insufficient offers to meet the CCA's needs, Grid West will trigger a limited offer obligation that will cause the consolidating parties to submit offers a proportional share of the needed.	
Reconfiguration – The process that allows release transmission rights from a given injection and withdrawal point to be use to issue rights between different injection and withdrawal points, e.g., the release of X MWs of rights from A to B can enable the issuance of Y MW of IWRs from C to D.	

Definitions	Acronyms
Reconfiguration Service – A Grid West transmission rights service that provides for acquisition of IWRs either from AFC and from released transmission rights by sellers. RCS is conducted through annual, monthly, intra-monthly auctions and day-ahead auctions.	**RCS**
Regional Network Service – A set of transmission service offered by Grid West within the Grid West Footprint that includes Capacity Expansion Service, Reconfiguration Service and Redispatch Service.	**RNS**
Regional Revenue Requirement Adjustment – A mechanism for recover of the revenue shortfall resulting from the shift from the OATT model to the RNS model, i.e., the elimination of non-firm and short-term firm revenues, etc., to enable offering of region-wide service without generating a cost shift among the transmission owners and their customers, to be as needed.	**R3A**
Regional Transmission Organization	**RTO**
Released Scheduling Flexibility – An offer to make available a portion of Existing Scheduling Flexibility that holder of pre-existing transmission rights has under its pre-existing arrangements. The offer to sell is made through the Day-Ahead Reconfiguration auction.	**RSF**
Reliability Coordinator – An organization that provides reliability coordination services to Reliability Authorities within a designated metered boundary.	**RC**
Remedial Action Scheme – An automatic system designed to implement a set of defined switching operations for a given event or set of events to protect the reliability of the interconnected system.	**RAS**
Reserve Market – A market used by Grid West to obtain capacity needed to meet the reserve requirements of the CCA.	
Right Data Management – The processes used by Grid West for Rights Inventoring, Rights Certification IWR Translation, or Bilateral Trade Registration.	**RDM**

Definitions	***Acronyms***
Rights – The ability to schedule injections and withdrawal of energy from the network without additional service fees (i.e. congestion costs)	
Rights Certification – Certification of Transmission Customer's existing transmission rights (becoming a CETR), when requested by these customers. Certification enables Transmission Customer's with Existing Scheduling Flexibility (ESF) to offer ESF in the DA-RCS.	
Rights Data Translation Management Database – A database containing the inventory of pre-existing rights and obligations of the Transmission Owners and the record of IWRs issued by Grid West.	**RTDM**
Rights Inventorying – Compilation of Transmission Owner rights obligations (TO obligations).	
RTO West – A potential FERC Order 2000 compliant RTO that would have covered the same area as the Geographic Territory, which was replaced by the Grid West Proposal.	
RTO West Stage 2 – The filing made with FERC by RTO West on March	
SeTrans ISA – A potential RTO whose operating territory would cover all or parts of Mississippi, Alabama, Florida and Georgia.	
Settlement – The process of making payments to sellers and sending bills to buyers in the markets operated by Grid West.	
Short-term Load Forecast – The expected hourly (or sub-hourly) load during an operating day.	**STLF**
Southwest Power Pool – An RTO covering all or portions of the states of Kansas, Arkansas, Oklahoma, Texas (panhandle and northeast) and New Mexico (eastern), which has historically been a combined power pool and a NERC reliability council.	**SPP**

Definitions	***Acronyms***
Supervisory Control and Data Acquisition – A system of remote terminal units and communications network that collects measurements (i.e. voltage magnitude, power flows, etc.) and status variables (i.e. status of breakers, switches, etc.) and transmit this data to the computers of the energy management system.	**SCADA**
System Access Requirement – A precondition for taking Regional Network Service associated with payment of embedded costs as specified in the Grid West Tariff.	**SAR**
The Structure Group (also Structure Consulting Group).	**TSG**
TO Tariff – The tariff to be issued by a TO covering interconnections and at the TO's option, covering the collection of embedded costs.	
Total Flowgate Capacity – The maximum capacity of a flowgate (a line or set of lines with a combined rating, i.e. a "rated system path").	**TFC**
Total Transmission Capacity or **Total Transfer Capability**	**TTC**
Transmission Agreement – The agreements executed by the Grid West with transmission owners or operators which, when effective, will allow Grid West to perform services over or with respect to the transmission owners' or operators' transmission facilities as such agreements may be amended from time to time.	**TA**
Transmission Authority – An entity that ensures the reliability of the bulk electric transmission system within a Transmission Authority Area, i.e., GWMT for Grid West. The Transmission Authority has the responsibility and authority to direct and coordinate the operation of transmission facilities within its area to maintain the reliability of the bulk electric system.	
Transmission Customer – An entity taking transmission service under the Grid West Tariff or under a Transmission Owner Tariff which provides for transmission capacity management of the TOs facilities by Grid West. (Figure 1 shows the relationship between Market Participants, Members, Transmission Customers and Transmission Owners.)	**TC**

Definitions	***Acronyms***
Transmission Operator – An entity that operates transmission facilities, whether they are owned by that entity or operated on behalf of another Transmission Owner.	
Transmission Owner – A Grid West Member that owns, leases or otherwise has an ownership interest in facilities used for the transmission of electric energy in interstate commerce and has signed a Transmission Agreement. (Figure 1 shows the relationship between Market Participants, Members, Transmission Customers and Transmission Owners.)	**TO**
Transmission Provider – A provider of transmission services to qualified market participants under applicable transmission service agreements.	**TP**
Transmission Rights Basecase – A power flow type of process which uses existing injection and withdrawal obligations to determine AFC.	**TRB**
Transmission Services Liaison Group – A subgroup of the Regional Representatives Group charged with the responsibility of expanding the technical definition of the Beginning State market and operations features.	**TSLG**
Trustee Selection Committee – A term used in the Regional Proposal which has been replaced by Member Representative Committee.	**TSC**
WestConnect – A potential RTO under discussion whose territory would include Arizona and New Mexico and parts of Colorado, Texas and Nevada.	
Western Electricity Coordinating Council – The Western Electricity Coordinating Council (WECC) is the largest of the ten regional reliability councils of the North American Electric Reliability Council (NERC) and serves as a forum for its members to enhance communication, coordination and cooperation – all vital ingredients in planning and operating a reliable interconnected electric system.	**WECC**
Western Interchange Tool – A proposed method under consideration by WECC for providing automated calculation of interchange information.	**WIT**

Definitions	***Acronyms***
Western Interconnection – The set of synchronously operating electric utility systems located in the western United States, Canada and Mexico including the eleven western states (Washington, Oregon, California, Idaho, Utah, Arizona, Montana, Wyoming, Colorado, New Mexico and part of Texas), two western Canadian provinces (British Columbia and Alberta) and some facilities in Mexico.	
Withdrawal Point – A point at which energy leaves the Grid West transmission system used to identify the "to" location of an IWR.	**WP**

TRANSMISSION SERVICE – MODULE 2

Transmission Rights Reconfiguration – Describes the implementation of the reconfiguration service: mechanisms for determining pre-existing obligations, auction rules and pricing of IWRs sold and purchased. A series of auctions addresses different time periods:

- Annual for monthly on-peak and off-peak IWRs.
- Monthly for monthly on-peak and off-peak IWRs for the balance of the annual period of the auction cycles.
- Intra-monthly for daily on-peak and off-peak IWRs for the balance of a month.
- Day-Ahead for hourly IWRs for the next day. The Day-Ahead Reconfiguration Service (DA-RCS) will have an enhanced feature to enable trading of scheduling flexibility options.

Day-Ahead Redispatch – Describes the day-ahead redispatch service envisioned in the original Regional Proposal and explains how the objectives of day-ahead redispatch will be met by enhancements to the Day-Ahead Reconfiguration Service without encountering the difficulties of reconciling day-ahead bids with real-time imbalances that were discovered during TSLG's Layer 1 work.

Bilateral Trading – Evaluates the effects of Grid West proposed services and functions on current bilateral trading practices within the Grid West Managed Transmission System.

Rights Data Management – Describes the processes and functions used by Grid West to manage transmission rights data, including:

- Inventorying of the injection and withdrawal commitments associated with pre-existing agreements and obligationsl
- Certification of existing rights to enable the release of scheduling flexibility options into the day-ahead reconfiguration auction.
- Translation of certified existing transmission rights into IWRs, either in whole or in part, prior to release into reconfiguration auctions.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

In this white paper, we describe the proposed design of Grid West Transmission Rights Reconfiguration Service (RCS) that is intended to facilitate acquisition of transmission rights by Transmission Customers.[1]

The principal attributes of the proposed Grid West Reconfiguration Service are as follows:

- Transmission rights offered into RCS are translated into standardized tradable instruments called "Injection/Withdrawal Rights (IWRs)" to facilitate their trading;
- Scheduling flexibility associated with Grid West certified existing transmission rights (CETR), called "Existing Scheduling Flexibility (ESF)," can be directly offered into RCS for trading;
- In RCS, Grid West trades IWRs and ESFs through a centralized flow-based clearing auction that combines offers for IWRs and ESFs and the GWMT Available Flow Capacities (AFCs) to match bids to acquire IWRs;
- The RCS auction objective is to maximize the value of all IWR trades; hence, priority to buy IWRs goes to those who value these IWRs the most (bids to buy them at higher prices) and priority to sell IWRs or ESFs goes to those who offer to sell them at lower prices;
- Transmission Customers who choose not to participate in RCS retain their CETRs and their associated scheduling flexibilities for use in energy scheduling;
- Transmission Customers can choose not to offer their IWRs, whether voluntarily translated from their existing rights or acquired through other mechanisms, into RCS;
- Transmission Customers who voluntarily translate part or all of their existing rights into IWRs and then choose not to offer such IWRs into RCS retain their existing transmission rights and their associated scheduling flexibilities;
- Transmission Customers whose offered IWRs and/or ESFs are not traded in the RCS will retain their CETR and their associated scheduling flexibilities for use in energy scheduling;
- Transmission Customers whose offered IWRs and/or ESFs are only partially traded in the RCS will retain and adjust CETR, which reflects the remaining flexibility of their original CETR for use in energy scheduling;
- In order to enable Transmission Customers to acquire IWRs in a timely fashion, Grid West allows trading of IWRs of various durations, from one hour to one year, through multiple RCS timelines;
- RCS includes market rules that address known market power concerns; and

[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.

- To the extent possible, RCS leverages existing business processes and technology solutions from existing RTOs and ISOs in order to minimize its overall cost of implementation and operation.

2.0 PROBLEM STATEMENT

One of Grid West's primary region-wide responsibilities is to improve the availability of transmission capacity to all transmission customers in order to enable efficient energy transactions within its regional footprint. Given the fundamental requirement that all transactions that schedule to use the Grid West Managed Transmission System (GWMT) must have applicable physical transmission rights, it is then necessary for Grid West to offer services that will greatly facilitate the trading of transmission rights among willing Transmission Customers. Grid West's Reconfiguration Service (RCS) is the most important component of such services.[2]

3.0 OBJECTIVES AND DESIGN CRITERIA

Reconfiguration service allows IWRs to be awarded to Transmission Customers[3] using the IWRs and ESFs offered into the market by other Transmission Customers as well as available capacity in GWMT. In order to provide reconfiguration services, Grid West will set up a sequence of markets and operational protocols to match bids and offers of IWRs with various time spans. The trading algorithm, a clearing auction, is designed to match IWR bids with IWR and ESF offers and AFCs in the most economically efficient manner[4] while complying with all physical and contractual constraints that govern the operation of the GWMT. The critical design criteria for RCS are:

- RCS should, to the extent possible, use standardized tradable instruments to facilitate trading of transmission rights;
- RCS should use a centralized auction to facilitate trading of IWRs among Transmission Customers by combining the IWR and ESF offers and the GWMT Available Flowgate Capacities (AFCs) [5] to award IWR bids;
- RCS should maximize the value of IWR trades as its objective;

---

[2] Another major Grid West service that supports the RCS function is Rights Data Management (RDM). RDM is presented in a companion white paper.

[3] Transmission Customer refers to all entities that use the GWMT. These include all entities that are currently classified as Transmission Customers (load and supply) as well as the load-serving functions of the existing TOs.

[4] For our purposes, economic efficiency refers to maximizing value of transmission rights trade whereby available transmission resources are allocated to those who have the most valuation of such resources. This objective is also known as maximizing "social welfare" or "market surplus."

[5] Available flow capacity refers to the capacity on transmission flowgates that are not reserved by existing transmission rights or not reserved by IWRs acquired through all available means of acquiring IWRs including previous RCS auctions.

- RCS should allow the Transmission Customers who choose not to participate in RCS, to retain their Grid West certified existing transmission rights (CETRs) and their associated scheduling flexibilities;
- RCS should be voluntary;
- RCS should allow Transmission Customers whose offered IWRs and/or ESFs[6] are not traded in the RCS to retain their CETR and their associated scheduling flexibilities;
- RCS should allow Transmission Customers whose offered IWRs and/or ESFs are only partially traded in the RCS to retain adjusted CETR with adjusted associated scheduling flexibilities based on the extent of the partially traded rights;
- RCS should enable Transmission Customers to acquire IWRs of desired durations and in a timely fashion to the extent possible;
- RCS should include market rules that address known market power concerns; and
- RCS should, to the extent possible, leverage existing business processes and technology solutions from existing RTOs and ISOs.

The proposed RCS solution, as presented in this white paper, is intended to satisfy all the above design objectives and criteria.

4.0 RCS PROCESS AND METHODOLOGY

RCS consists of processes and functions that allow Transmission Customers to voluntarily trade (acquire or release) physical transmission rights within GWMT. A normal prerequisite for efficient trading of physical transmission rights is the introduction of "standardized tradable instruments" that can be readily understood and traded in primary and secondary markets by Transmission Customers. Grid West has introduced the Injection/Withdrawal Right (IWR) as such a standardized instrument.[7] An IWR represents the scheduling right to inject power at a scheduling point (bus or hub) in the GWMT and withdraw the same power at another scheduling point (bus or hub) in the GWMT within an applicable timeframe. A complete definition of the IWR along with its attributes is presented in the accompanying Grid West Glossary document. In addition Grid West is allowing the scheduling flexibilities held within existing transmission rights (ESFs) to be offered into some RCS processes.

RCS consists of processes and functions that allow Transmission Customers to acquire or release physical transmission rights in GWMT in the form of IWRs and/or ESFs. In each RCS

[6] The holder of ESF may not be the same entity as the owner of the associated transmission right.

[7] While standardized trading is the main benefit of adopting IWRs, Grid West initially moved towards IWRs for two practical reasons: (1) better alignment between schedules and actual system use should improve reliability, and (2) elimination of the dual constraints of maintaining schedules and actual flows separately, each within limits, should improve throughput. Once flow-based scheduling was decided upon, the use of IWRs was a natural consequence. The need to specify IWRs in a way that produces standardized products was then recognized. For additional details please study the accompanying market overview paper.

process, a Transmission Customer can offer for sale the applicable[8] IWRs that they own or have acquired through any of the following means:

1. IWRs that have been voluntarily translated based on all or parts of their CETR;[9]
2. IWRs that have been acquired through transmission expansion projects;
3. IWRs that have been bilaterally acquired and registered with Grid West;
4. IWRs that have been voluntarily translated by the new owners of the bilaterally traded CETR;[10] and
5. IWRs that have been acquired from previous RCS auctions.

Grid West combines all offered IWRs with the Available Flowgate Capacities (AFCs) of the GWMT to conduct its RCS auction. In addition, Grid West, as part of Day-Ahead reconfiguration service, allows its participants to offer the existing scheduling flexibilities (ESFs) that they hold into the IWR auction.[11]

In order to allow for timely and efficient acquisition of IWRs, Grid West performs the reconfiguration service on regular intervals through the following processes:

- Annual Reconfiguration Service (A-RCS): A-RCS is conducted once a year and is intended to trade monthly peak and off-peak IWRs (24 products) for all 12 months of the operating year.
- Monthly Reconfiguration Service (M-RCS): M-RCS is conducted once a month and is intended to trade monthly peak and off-peak IWRs for each of the remaining months of the operating year.
- Intra-Monthly Reconfiguration Service (I-RCS): I-RCS is conducted on daily basis and is intended to trade daily peak and off-peak IWRs beginning with two days after the auction each of the days in the remainder of the operating month.

---

[8] Applicability applies to the timeframe and time format of the IWR vis-à-vis the specific RCS timeline. For example monthly peak IWRs can be offered in annual and monthly IWR auctions; however, they cannot be offered into the daily IWR auction.

[9] The process of translating existing rights into IWRs is covered in an accompanying white paper on Rights Translation.

[10] Bilateral trading of CETRs requires the approval of the impacted Transmission Owner and Grid West.

[11] In the future ESFs may be offered into other RCS process timelines.

- Day Ahead Reconfiguration Service (DA-RCS): DA-RCS is also conducted on daily basis and is intended to trade IWRs on an hourly basis for the 24 hours of the next day.

After the DA-RCS and up to scheduling deadline, IWRs may still be bilaterally acquired outside RCS processes. These bilaterally traded IWRs must be registered with Grid West before the "registration deadline" if they are to be used for energy scheduling. During the same time period, Transmission Customers are able to also acquire non-firm rights from Grid West to use for their energy scheduling.

Figure 4a presents the relative sequence and timelines of the A-RCS, M-RCS, I-RCS and DA-RCS processes.[12]

[12] In this paper and in Figure 1, we have assumed that annual RCS process is based on the "water year" (September 1st through August 31st). Other alternative annual duration can readily be used.

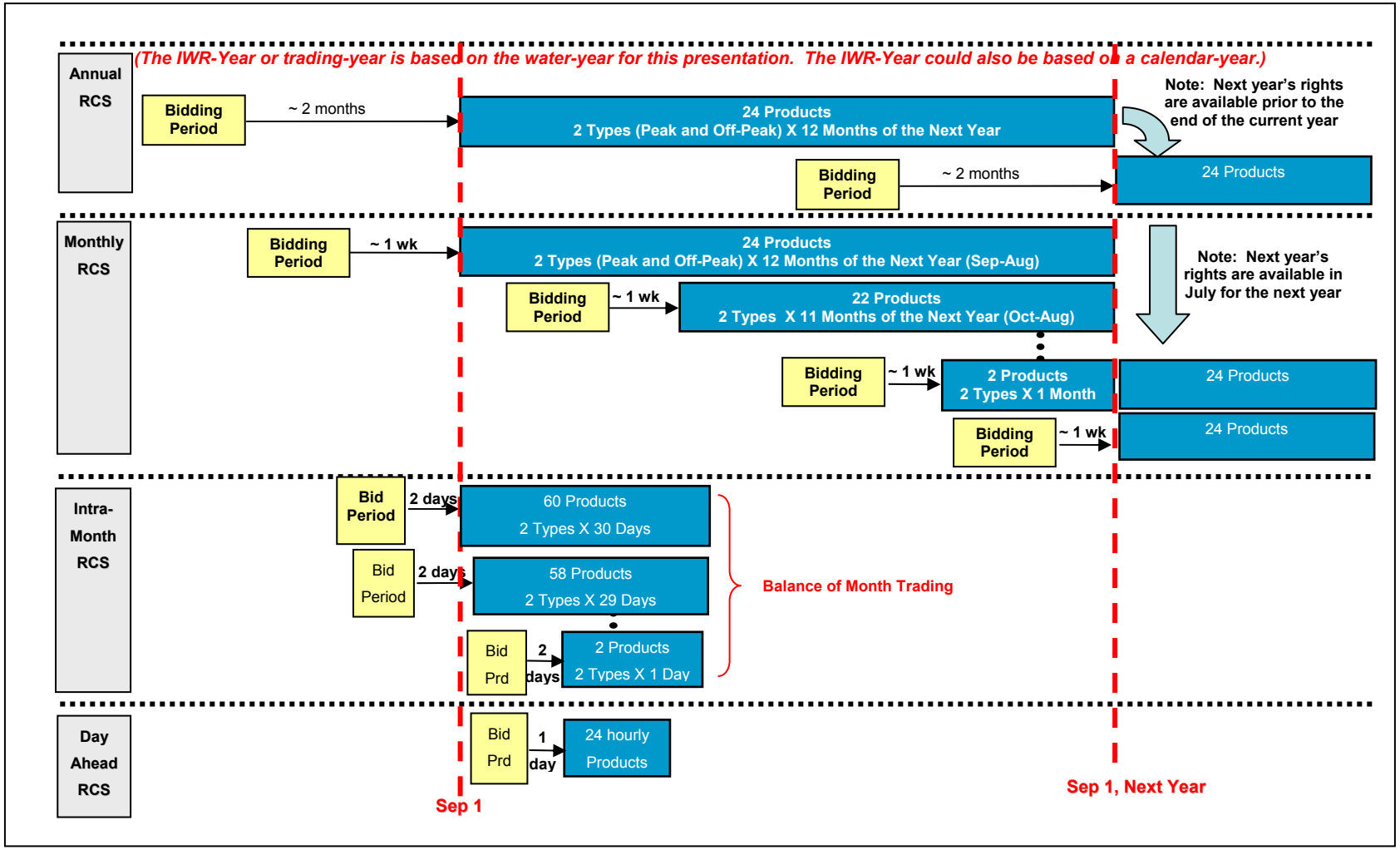


Figure 4a - RCS timelines

The proposed process flow diagram for a typical RCS process is presented in Figure 4b, which applies to all four RCS timelines. Figure 4b also shows the approximate timeline for these processes, which are as follows:

1. Development of a Transmission Rights Basecase (TRB) by Grid West for each RCS auction. This process should be performed well in advance of each RCS auction: at least two weeks for A-RCS, one week for M-RCS, one day for I-RCS and eight hours before DA-RCS.
2. Calculation and Posting of Available Flow Capacities by Grid West for each RCS auction. This process is performed right after TRB is complete.
3. Submittal of IWR offers and bids by Transmission Customers through a secure Web delivery system and during the applicable time window. Deadlines for such submittals are dependent on the RCS timeline and would vary from one day for the A-RCS and M-RCS to one hour for I-RCS and DA-RCS. Transmission Customers may also offer their existing scheduling flexibility (ESF) into DA-RCS by specifying and submitting their Intended Retained Rights (IRRs). IRRs would be presented as a set of injections and withdrawals (or a range of values for injections and withdrawals) at applicable scheduling points.
4. Validation of IWR offers and bids and ESF offers (IRR submissions) by Grid West to ensure that all offers and bids are valid and comply with all rules of the RCS process. Validation of IWR offers and bids and IRR submissions is performed virtually at the time of these submissions to ensure that they are compatible with the underlying rights data.
5. Execution of IWR Auction by Grid West during the relevant time window for the specific auction.
6. Posting of IWR auction awards and prices by Grid West no later than one hour after the auction is complete for DA-RCS and I-RCS and no later than a few days after the auction is completed for M-RCS and A-RCS.
7. Updating of the Rights Data Management (RDM) Database[13] with the updated IWR awards.

[13] Please refer to the accompanying Rights Data Translation Management (RDTM) white paper for the detail of such data.

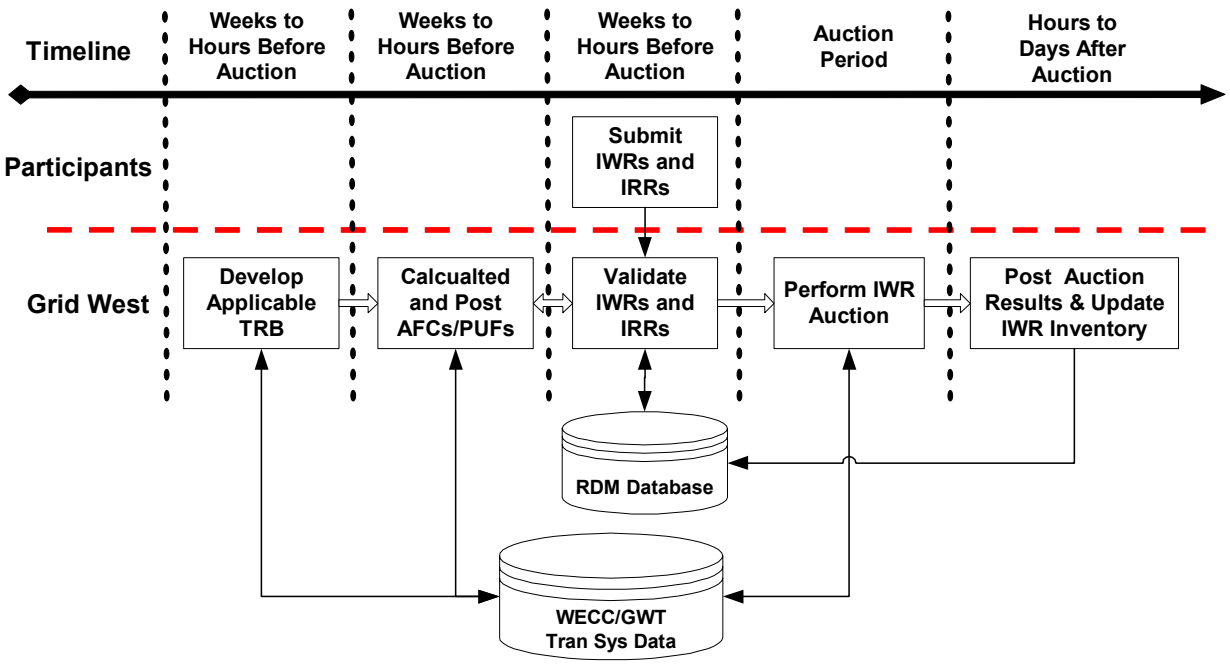


Figure 4b - RCS Process Flow and Timeline

RCS processes are described in greater detail in the following sections. These processes are essentially the same for A-RCS, M-RCS and I-RCS as they apply to the applicable auction scenarios within these reconfiguration processes. However, DA-RCS has several unique features due to its consideration of ESFs. These unique features are covered in Section 4.6.

4.1 Transmission Rights Basecase (TRB) Development

Transmission Rights Basecase (TRB) is the foundation of the IWR auction process. The TRB not only provides the transmission system data used by the IWR auction model but also is used to identify the AFCs that the model will use for the IWR auction.[14] TRB is developed using one or more "power flow" saved cases representing the WECC transmission system for the operating condition of the relevant auction scenario with emphasis on modeling of the GWMT.[15]

Starting from a full WECC case, Grid West will develop the base transmission system data that will be used for each auction scenario within various RCS processes. The data will include

[14] The RCS processes presented in this white paper are based on study of the system under normal operating conditions and a linearized network model (DC Power Flow). Alternatively, these studies can be performed by including system contingency conditions and/or with an AC Power Flow model.

[15] The WECC transmission system beyond GWF may be represented in full or with a simplified equivalent model. A full WECC network model provides a more complete solution especially as related to WECC loop flows; however, it will also require more computational power and frequent information updates from neighboring transmission operators (directly or through WECC) and an enhanced computing capability.

system topology data, transmission line parameter data and the relevant load distribution factors.[16]

4.2 AFC Calculation and Posting

Before IWR auctions, Grid West will compute and post AFCs and Path Utilization Factors ("PUFs"). Grid West will calculate AFCs in two steps for A-RCS, M-RCS and I-RCS markets and in a single step for DA-RCS. In Step 1, Grid West's goal is to account for flowgate capacities subscriptions due to Transmission Owner (TO) Obligations and Transmission Customer CETRs.[17] Given the historical knowledge of GWMT use for TO obligations and CETRs, Grid West can estimate the capacity subscriptions for these rights and the remaining AFCs using an approach called X-factor discounting - this approach is presented further below in this section. In Step 2, Grid West's goal is to account for the subscribed flowgate capacities due to "active IWRs."[18] In this step, Grid West assumes that IWRs will be used in ways other than their traditional ETR use, if applicable, after acquisition by Transmission Customers and hence IWRs are treated differently than TO obligations and ETRs and as "non-simultaneous physical rights."[19] Special power flow solutions are used to determine the subscribed flowgate capacities due to IWRs.

The two steps of AFC calculation are presented in additional detail below:

Step 1: Grid West will set up the power flow case using the TRB for each auction scenario. All TO obligations and CETRs, adjusted for active IWRs[20], are simultaneously modeled in this case. In modeling adjusted TO obligations and CETRs for an auction scenario, we use their expected configuration of these obligations and rights for that auction scenario as specified by the TOs and the CETR holders and then adjust them for active IWRs. The model accounts for counterflow effects of the adjusted TO obligations and CETRs.

The power flow analysis calculates the unsubscribed transmission capacity on all transmission flowgates. Available flow capacities are subsequently discounted based on the X-factor methodology that takes into account historical use of the flowgate. X-factor approach is summarily presented in Section 4.2.1 below. If, at this stage, a transmission flowgate is

---

[16] For A-RCS and M-RCS, typical peak and off-peak basecases are developed for the applicable monthly auction scenarios. For I-RCS daily peak and off-peak basecases are developed for each auction day. Alternatively the same peak and off-peak basecases can be used for the all days covered in the I-RCS. Grid West can potentially develop as many as 24 hourly basecases for DA-RCS. We expect, however, that the same basecase will be by and large used for all 24 hours IWR auctions.

[17] CETRs correspond to those existing transmission rights (ETRs) that have been specifically identified and certified by Grid West based on request by their owners and in coordination and approval of the impacted Transmission Owners. Once certified, TO obligations are adjusted to account for the certification. Please review the accompanying paper on Rights Data Management white paper for additional details.

[18] Active IWRs are those awarded as part of a previous IWR auction, traded bilaterally and registered with Grid West, and those translated IWRs that are offered into the current RCS process. All long-term IWRs acquired as part of the Grid West capacity expansion service are also counted as part of the Active IWRs.

[19] Non-simultaneous physical rights refer to rights whose counterflow subscriptions on a flowgate are ignored while their same direction subscriptions on a flowgate are additive. This characteristic of non-simultaneous physical rights is similar to Option FTRs traded and used in the PJM market.

[20] Adjustment to account for active IWRs corresponds to taking out the rights associated with active IWRs from TO obligations and CETRs.

oversubscribed, the AFC for that flowgate is set to zero. Finally, the AFC in the opposite direction of the dominant flow is set equal to line TFC. The example of Appendix A elucidates this step.

Step 2: This step of AFC calculation entails accounting for all active IWRs. Another power flow analysis, in which all active IWRs are treated as non-simultaneous physical rights (counterflow effects are not accounted for), will identify flowgate capacity subscriptions due to these IWRs and, as a result, the AFC in both directions on all identified transmission flowgates. Here again, if a transmission flowgate is oversubscribed in any direction, the AFC for that flowgate is set to zero.[21]

The power flow analysis used to calculate will also calculate the Path Utilization Factors (PUFs) for the set of monitored flowgates and identified scheduling point (buses/hubs). For a monitored flowgate, each PUF signifies flow contribution on that flowgate as a fraction of the injection (or withdrawal) at a scheduling point within GWMT. The AFCs and PUFs calculated in this fashion are used in the IWR auction process and will be posted through the Grid West market information system and all relevant OASIS sites.[22]

The example of Appendix A should help elucidate the process of Step 2.

4.2.1 X-Factor Methodology

Intended to account for diversity in the use of existing rights, whether as TO obligations or CETRs, X-factor methodology entails discounting AFCs calculated in Step 1 of AFC calculation for all flowgates where counterflows were present. In effect AFCs are discounted using a fractional multiplier (X-factor) specifically calculated for that flowgate. For these flowgates, X-factors reflect the fact that transactions based on adjusted TO obligations and CETRs may not occur simultaneously and hence their full counterflow impact should be discounted.[23] For a flowgate where all the flows are predominantly in the same direction, the X-factor can be greater than one (1) to account for the fact that all these additive transactions may not occur simultaneously either.

Basically flowgate X-factors account for the following sources that influence actual use of a flowgate versus the net subscriptions calculated for that flowgate, as calculated from the power flow analysis:

- Simultaneity of the actual transactions based on transmission rights that are used to calculate flowgate subscription; and
- Flowgate capacity due to stochastic and "unscheduled" events such as system outages or loop flows.[24]

---

[21] Given the IWR auction methodology, over-subscription at this stage should not happen unless there are changes in system configuration since the last IWR auction. There is no need to account for X-factor in these calculations.

[22] It is expected that all existing OASIS sites that cover GWMT will be consolidated into Grid West market information system (MIS).

[23] In practice rather than discounting the AFC after accounting for ETR subscriptions [DEFINE SUBSCRIPTION], the X-factor may be used to discount the counterflows when calculating the subscription. The value of X-factor for a flowgate that is used in this fashion will be different from the X-factor which is calculated in process above and can be calculated using off-line power flow studies based on historical use of GWMT.

[24] In accounting for loop flows it is important that we account for the operation of phase shifters.

X-factor for a flowgate is calculated by comparing historical flows with calculated subscriptions, from the power flow analysis of Step 1, on that flowgate. Under this methodology, every flowgate will have its own X-factor value for each RCS auction scenario. X-factor values should be updated at regular intervals using power flow studies and actual use information of the GWMT and more importantly the outcome of schedule adjustment/curtailment process. If there are extensive schedule adjustments or curtailments during the schedule adjustment/curtailment process, the X-factors should be reduced. If there are consistent unscheduled transmission capacities during the schedule adjustment/curtailment process, X-factors may be increased.[25]

4.3 IWR Validation

IWR validation verifies IWR offers and bids and ESF offers (IRR submissions) before they are used in the IWR auction. The IWR validation function entails verifying the following attributes of the IWR:

- Participant Validation: Validate that the entity offering or bidding IWR or ESFs is an authorized Transmission Customer; and verify that the entity has the proper trading rights and meets credit requirements to fully or partially participate in the RCS.
- IWR/ESF Value Validation: Validate that the offered IWR/ESF actually exists based on the physical rights inventory database (RDM database).
- Ownership Validation: Validate that the entity offering IWR/ESF is the "registered owner" of the right per Grid West physical right inventory database (RDM database).
- Timeframe Validation: Validate that the offered IWR is applicable to the timeframe of the auction. Timeframe applies both to the scenario dimension as well as the duration dimension of the IWR.
- Syntax Validation: Validate data entry syntax.

Only IWRs offers and bids and ESF offers (IRR submissions) that pass all these validation steps will be allowed in and used in the IWR auction.

4.4 IWR Auction

The IWR auction uses a linearized Optimal Power Flow (DC OPF)[26] model that represents the physical characteristics of the transmission system in a DC power flow framework to perform the auction.[27] The auction matches IWR and ESF offers, IWR bids and AFCs with the objective of maximizing the value of traded transmission rights subject to all contractual and physical constraints of the transmission system.[28]

---

[25] Hence there will be knowledge-based judgment applied in the calculation of X-factors.
[26] One form of model that is well established and may be used is a DC Optimal Power Flow that simulates flow distribution effects without adding the complexity of modeling nonlinear AC effects.
[27] Losses are ignored in the IWR auction.
[28] The solution methodology is essentially the same as the algorithms used by existing RTOs and ISOs for auctioning Option based Financial Transmission Rights (FTRs). These algorithms also use an optimal power flow model (usually a linearized/DC OPF) for the FTRs auction to ensure that the awarded FTRs, if actually realized as physical transactions, do not violate system operating constraints (i.e. there is no over-subscription of transmission flowgates). The objective of these FTR auctions is to ensure revenue adequacy for the RTO/ISO as the RTO/ISO

An IWR auction is conducted for each relevant auction scenario; for example, there are 24 auction scenarios (monthly peak and off-peak for the next 12 months) for the annual RCS. Auction scenarios are either solved separately or tied together if IWR offers or bids require it. For example, if one or more Transmission Customers offer to sell or bid to buy 24 equal IWRs for all of the 24 auction scenarios in the annual RCS (annual IWR strip/block), the auction model will tie all 24 auction scenarios together for the annual RCS.[29] The same principles apply to monthly RCS except that, rather than solving for each month of the 12 months of the year, it is done for each month for the remaining month(s) of the year. IWRs translated from CETRs, and all applicable awarded IWRs from previous RCS processes or those applicable IWRs acquired through bilateral trades, and registered with Grid West, can be offered in the intra-monthly auction as daily peak and off-peak IWRs.

In intra-monthly RCS auctions, peak and off-peak IWRs are auctioned on a daily basis for the remaining days of the month (balance of the month starting from the second day after the auction).[30] Hence, for a particular intra-monthly RCS, there could be as many as 62 peak and off-peak auction scenarios, depending on the length of the months and the day when the auction is performed. IWRs translated from CETRs, and all applicable awarded IWRs from previous RCS processes or those applicable IWRs acquired through bilateral trades, and registered with Grid West, can be offered in the intra-monthly auction as daily peak and off-peak IWRs.

In DA-RCS process, IWRs are auctioned on an hourly basis for the next business day[31] (24 auction scenarios). IWRs translated from existing rights, applicable IWRs awarded through previous annual, monthly and intra-monthly RCS processes or acquired through bilateral trades, can be offered in the Day-ahead auction as a string of hourly IWRs. ESFs can also be offered in the DA-RCS.

IWR sellers will receive the difference in clearing prices at the relevant scheduling points for the awarded IWRs. These clearing prices are standard output of the DC-OPF model that is used for the IWR auction. Buyers of IWRs will pay difference in clearing prices at the relevant scheduling points for the IWRs purchased through the IWR auction.

Those who release ESF into DA-RCS will receive payments equivalent to difference between maximum value of their flexible rights, as determined based on all IWR bids and offers and the value of their intended retained rights (IRRS).[32]

---

has to pay owners of the FTRs based on congestion revenues in the DA energy market. In Grid West's case, the objective of the IWR auction is to ensure that maximum IWR awards are made and the identified transmission flowgates are not oversubscribed. Given that all transactions need to have existing transmission rights or IWRs before being accepted for scheduling, this should prevent over-scheduling of transmission flowgates.

[29] Solving all scenarios together entails significant added complexity for the solution algorithm.

[30] Note that these auctions will be performed on weekdays only.

[31] Note that these auctions will be performed on weekdays only. As a result, if daily auctions are desired for weekend days, three daily auctions will be performed on Fridays (one for the next Saturday, one for the next Sunday and one for the next Monday).

[32] This payment is mathematically calculated using the value of the AFCs that is released on the congested flowgates by the ESF offer/release and is calculated as the product of the magnitudes of released AFCs on all congested flowgates and the shadow price of these flowgates. Shadow price of a flowgate is the value of increasing the capacity of the flowgate capacity by one MW and is a by-product of the DC-OPF that performs the IWR auction.

4.5 Auction Results Posting

All IWR awards will be privately communicated through timely posting on the secure part of the Grid West market information system (MIS) - please refer to the accompanying white paper on MIS. Public IWR information, e.g., clearing prices for scheduling points, and the total IWR quantities awarded in the auction will be posted on the public side of Grid West market information system and all applicable OASIS sites. The same information is also deposited into the RDM database for use in the next rounds of the RCS or for operational purpose.

4.6 DA-RCS Distinctive Features

There are several features in the DA-RCS process that are distinct from those of the other RCS processes. These distinct features of the DA-RCS are:

- Existing scheduling flexibilities (ESFs) of CETRs are allowed to be offered into DA-RCS by allowing ESF holders to specify/submit their intended retained rights (IRRs);
- TO obligations and CETRs are modeled with the full range of their scheduling flexibility for the AFC calculation as opposed to their expected value; and
- AFCs and PUFs are calculated in a single step and based on the assumption that translated ETRs and IWRs can create counterflow flowgate subscriptions (X-factors are again used to account for the fact the counter flows may not be simultaneous).

To accommodate these features, the DA-RCS auction model, although still DC OPF based, will use some form of an "internal dispatch model" to account for rights scheduling flexibility. The example of Appendix B should help elucidate these specific features.

5.0 INPUTS AND OUTPUTS

All RCS processes have similar input and output data. DA-RCS has a few additional input data requirements. Figure 4b showed the data flow diagram for a typical RCS process. In the following tables, we define each one of the inputs and outputs of these processes and present specific details for individual RCS timelines.

5.1 RCS Input

Table 5.1 presents the inputs to the RCS process.

Table 5.1 - Inputs to the RCS process

Input	Description	Timeline Differentiators
TO obligation	Aggregated transmission obligations of the TOs (stemming from existing contracts, coordination agreements, treaties, etc.) presented via the expected I/W obligation values (or range of	**A-RCS:** Expected monthly peak/off-peak I/W obligation values at all relevant scheduling points for every month of the year. **M-RCS:** Expected monthly peak/off-peak I/W obligation values at all relevant scheduling points for the remaining months of the year. **I-RCS:** Expected TO obligation daily

	values) at all relevant scheduling points and for the relevant auction scenario.	peak/off-peak I/W values at all relevant scheduling points for the remaining days of the month. **DA-RCS:** Actual TO obligation peak/off-peak I/W values or range of values at all relevant scheduling points.
CETR	Existing Transmission Rights of Transmission Customers as certified by Grid West and presented as the I/W right values (or value ranges) at all relevant scheduling points as well as overall rights constraint for the ETR.[33]	Applicable for DA-RCS only.
IWRs	Injection right value at one scheduling point and an equal withdrawal right value at another scheduling point for each of the applicable auction scenarios.	**A-RCS:** Monthly peak/off-peak IWRs for every month of the year. **M-RCS:** Monthly peak/off-peak IWRs for the remaining months of the year. **I-RCS:** Daily peak/off-peak IWRs for the remaining days of the month. **DA-RCS:** Hourly IWRs for the next business day.
Transmission System Data	"Power flow" type data for the WECC transmission systems. All GWMT to be presented. WECC system outside GWF may be presented in full or converted into an equivalent model for ease of analysis. Other transmission related data include the appropriate flowgate flow limits from the AFC calculation and outage schedules. X-factors for all "monitored" flowgates calculated based on offline studies is included as part of this information.	**A-RCS:** System topology, transformer and phase shifter tap positions, and X-factors for the 24 auction scenarios. **M-RCS:** System topology; transformer and phase shifter tap positions, and X-factors for the auction scenarios of the remaining months of the year. **I-RCS:** System topology; transformer and phase shifter tap positions, and X-factors for the auction scenarios of the remaining days of the year. **DA-RCS:** System topology; transformer and phase shifter tap positions, and X-factors for the next business day.

[33] Please refer to the accompanying Rights Data Translation Management (RDTM) white paper for the detail of such data.

Offers to sell IWR	Injection right and withdrawal right values at two specific scheduling points that corresponds with the IWRs owned by the offering entity per RDM database.	**A-RCS:** Monthly peak/off-peak IWR offers for every month of the year. **M-RCS:** Monthly peak/off-peak IWR offers for the remaining months of the year. **I-RCS:** Daily peak/off-peak IWR offers for the remaining days of the month. **DA-RCS:** Hourly IWR offers for the next business day.
Intended Retained Rights [IRR]	For DA-RCS, IRRs represent the rights that the Transmission Customers who hold the ESFs in the CETRs intends to keep for their own scheduling. IRRs are specified by the range of intended schedules (I/W values or range of values) at one or more applicable scheduling points.	Applicable for DA-RCS only.
Bids to buy IWRs	Injection right and withdrawal right values (equal values) at two specific transmission points in the system.	**A-RCS:** Monthly peak and/or off-peak IWR bids for one or more months of the year. **M-RCS:** Monthly peak and/or off-peak IWR bids for one or more months in the remaining months of the year. **I-RCS:** Daily peak/off-peak IWR bids for one or more days in the remaining days of the month. **DA-RCS:** Hourly IWR bids for one or more hours of the next business day.

5.2 RCS Output

Table 5.2 presents the outputs of a typical RCS process.

Table 5.2 - Outputs of the RCS process

Output	Description	Timeline Differentiators
AFCs & PUFs	Available flow capacity for the "identified flowgates" in the GWF transmission system as well as PUFs for the same flowgates and identified scheduling points (buses/bubs) - public data.	**A-RCS:** AFCs & PUFs for annual auction scenarios. **M-RCS:** AFCs & PUFs for monthly auction scenarios. **I-RCS:** AFCs & PUFs for intra-monthly auction scenarios.

		DA-RCS: AFCs & PUFs for daily auction scenarios.
Awarded IWRs	The "matched/reconfigured" IWRs (injection and withdrawal right values at the requested scheduling points) and the corresponding prices- private data.	**A-RCS:** Monthly peak/off-peak IWR awards for every month of the year. **M-RCS:** Monthly peak/off-peak IWR awards for the remaining months of the year. **I-RCS:** Daily peak/off-peak IWR awards for the remaining days of the month. **DA-RCS:** Hourly IWR awards for the next business day.
Awarded Scheduling Flexibility	The final retained right (RR) range per scheduling point and the payment amount for the flexibility released into DA-RCS - private data.	Applicable for DA-RCS only.
IWR Prices	IWR clearing prices - private data.	**A-RCS:** Monthly peak/off-peak clearing prices for all IWR scheduling points for all scheduling points for every month of the year. **M-RCS:** Monthly peak/off-peak clearing prices for all IWR scheduling points for all scheduling points for the remaining months of the year. **I-RCS:** Daily peak/off-peak clearing prices for all IWR scheduling points for all scheduling points for the remaining days of the month. **DA-RCS:** Hourly clearing prices for all IWR scheduling points for the next business day.
Auction summary	AFCs, total awarded MW for each flowgate, clearing prices for all scheduling points plus other summary information for the applicable auction scenarios will be posted onto market information system (MIS) - public data.	**A-RCS:** Monthly peak/off-peak AFCs and PUFS, total awarded MW for each flowgate, clearing prices for all scheduling points plus other summary information for all months of the year. **M-RCS:** Monthly peak/off-peak AFCs and PUFS, total awarded MW for each flowgate, clearing prices for all scheduling points plus other summary information for the remaining months of the year. **I-RCS:** Daily peak/off-peak AFCs and PUFS, total awarded MW for each flowgate, clearing prices for all scheduling points plus other summary information for the remaining

		days of the month. **DA-RCS:** Hourly AFCs and PUFS, total awarded MW for each flowgate, clearing prices for all scheduling points plus other summary information for the next business day.

6.0 ROLES AND RESPONSIBILITIES

Table 6 describes the roles and responsibilities of Grid West and its participants in the RCS process.

Table 6 - Grid West and its participants' roles and responsibilities in RCS

RCS Timeline	Grid West	Transmission Owners	Transmission Customer
Pre-Auction	▪ Develop TRB basecase ▪ Publish basecase ▪ Calculate and post AFCs and PUFs	▪ Provide data and assist with building TRB and calculation of AFCs and PUFs ▪ Provide base data used for validation	▪ Monitor
Auction	▪ Validate bids/offers ▪ Carry out auction	▪ Monitor	▪ Submit IWR bids/offers ▪ Submit IRRs for DA-RCS
Post Auction	▪ Post IWR awards and prices and other market information ▪ Post retained rights and payments for DA-RCS	▪ Monitor	▪ Download market results

7.0 REVENUE ALLOCATION

IWR auction over a period is expected to produce net revenue for Grid West due to the sale of AFCs as part of the IWR auction. Such net revenues, if any, will be used to reduce Regional Revenue Requirement Adjustment account (R3A).

8.0 MARKET POWER AND MARKET EFFICIENCY CONSIDERATIONS

Market monitoring processes and mitigation rules are integral parts of all competitive markets. Market mitigation measures have been used proactively (market rules) and reactively (sanctions

and penalties) to ensure that markets are free of market power abuses. On the negative side, market mitigation measures, whether proactive or reactive, have the tendency to limit the competitiveness of the markets, so there should be a balance between rules to mitigate market power and the need for the market to behave "competitively" without undue administrative interventions.

The Grid West reconfiguration service, as presented in this white paper, is intended to complement existing transmission rights trading in GWF. As such we do not foresee that RCS itself would create additional opportunities for market power abuses. Nevertheless, the following market mitigation processes should be considered for the Grid West RCS to address any lingering concerns:

- Monitoring and potentially limiting of IWR ownership concentration among Transmission Customers especially for those with dominant energy positions;
- Monitoring of purchase, resale and use patterns of IWRs by Transmission Customers especially for those with dominant energy positions; and
- Monitoring IWR auction participation, awards and prices, with the possibility of instituting price caps and/or other mitigation measures if needed to address identified problems.

9.0 MARKET BENCHMARKS

The underlying approach that Grid West uses to account for transmission rights is different from those of the existing RTOs and ISOs in North America. At the heart of this difference is that transmission rights in existing RTOs and ISOs are solely intended to provide a financial hedge against ex-post congestion charges. Hence, market participants in these RTOs and ISOs do not need to own transmission rights in order to schedule their transactions with their RTO or ISO.[34]

Since most FTRs offered by existing RTOs and ISOs are purely financial instruments, practically every MW of the transmission system capacity is available for the FTR auction (and later for the Day-Ahead energy auction). Hence, the FTR auctions are normally performed in segments where portions of the available transmission capacity are auctioned off. In addition, due to the financial nature of FTRs, most existing RTOs and ISOs only conduct annual and monthly FTR auction for seasonal or monthly peak and off-peak FTRs. On the other hand, since Transmission Customers do need transmission rights for scheduling purposes, Grid West needs to conduct additional auctions close to scheduling time in order to ensure that market

[34] Financial rights in these RTOs and ISOs are referred to as Financial Transmission Rights (FTRs) and they are normally in the form of point-to-point (a point may be a bus, a zone or a hub) Obligation FTRs. Only CAISO and ERCOT currently offer transmission rights that are slightly different. In the case of CAISO, the transmission right (called Firm Transmission Right) provides its holder with scheduling priority as well. In ERCOT, transmission rights (called Transmission Congestion Rights) are Flowgate rights. Holders of FTRs receive payment equal to the amount right ownership and the value of FTR as determined by Locational Marginal Prices or LMPs. The funds to pay FTR holder are collected as congestion charges from market participants in the RTO/ISO Day-Ahead (DA) energy market. In rare instances, an Obligation FTR holder may have to pay for transmission system congestion if his/her right is in the direction of counterflow on a congested flowgate. In the process of transmission rights administration by these RTOs and ISOs, holders of existing rights, such as LSEs or direct retail customers, are often offered Auction Revenue Rights (ARRs) and/or FTRs equivalent for their existing rights to account for their existing rights.

participants have access to sufficient mechanisms (e.g., RCS processes) to purchase transmission rights.

Furthermore, Grid West's DA-RCS process, which allows ESFs to be offered into the IWR auction, is not comparable to any transmission rights trading mechanism used by existing RTOs and ISOs.

Despite these dissimilarities in the fundamental application of transmission rights, there are underlying similarities in processes that Grid West uses for auctioning transmission rights and those used by existing RTOs and ISOs. These similarities, presented in table 9a below, allow most computational tools and techniques used by the existing RTOs and ISOs to be, by and large, usable for Grid West in its various RCS processes.

Table 9a - Comparison of Grid West RCS process and FTR trading by existing RTOs/ISOs

Auction Attribute	Grid West	PJM	ERCOT	MISO
IWR Auction Mechanism	OPF-based clearing auction with the objective of maximizing IWR auction value	Option-based FTR auction engine uses fundamentally the same OPF-based clearing auction algorithm as the one used for IWR auction.		
Auction Pricing	Based on clearing price differences at the corresponding scheduling points of the IWR.	Based on the difference in LMPs at the two ends of the FTR.		
Revenue Allocation	Net revenue from IWR auction is applied towards R3A.	Any net revenue goes towards paying down the embedded cost of the transmission system.[35]		

Table 9b shows the FTR products and the frequency of trading these products by some of the existing RTOs and ISOs.

Table 9b - FTR products and their Frequency of Trading

RTO/ISO	Frequency of FTR Auction	FTR Duration (Months)
MISO	Annual Monthly	12 1
ISO-NE	Annual Monthly	12 1
NYISO	Semi Annual	6 - 12

[35] Existing RTOs and ISOs normally pay the net FTR auction revenues to ARR holders - normally those who own existing rights such as LSEs.

	Monthly	1 60
PJM	Annual Monthly	12 1
ERCOT	Annual Monthly	12 1
Grid West (IWR Trading)	Annual (A-RCS) Monthly (M-RCS) Daily (I-RCS) Hourly (DA-RCS)	12 1 1 day 1 hour

10.0 TECHNOLOGY SOLUTIONS

As described earlier, the technologies required for the RCS implementation are by and large already available and are in use by the industry. Relational databases that would house the transmission owner obligations and translated transmission rights data (RDTM database) can be readily procured and designed. Transmission System Database is a standard construct of most power flow solution vendors. Standard secure Web interfaces can be used to exchange private and public input and output data with Transmission Customers.

Participants' input data validation process uses straightforward algorithms and relies on the RDM database. In addition, IWR auction model for A-RCS, M-RCS and I-RCS is rather a complex model; however, such a model is already in use by existing RTOs and ISOs.

Grid West's DA-RCS auction process, on the other hand, has the unique feature of accounting for scheduling flexibilities and as such requires special new modeling features that we believe can be readily added to the existing auction models offered in the industry.

11.0 ORGANIZATION REQUIREMENTS

Table 10 presents the resource requirements for the operation and support of RCS business processes and technologies.[36]

Table 11 - RCS Staff Requirements

Division	Department	Role	Responsibility
Market Operations	Forward Markets	Manager	▪ RCS management

[36] We assume that Grid West will acquire, rather than build, all the technology resources needed for the RCS functionality. This assumption is essential in re-sourcing the operation of the RCS process and its technologies. We have not included administrative requirements in this table. We have not included the infrastructure (LAN/WAN, office automation, etc.) support requirements either. The Division and Departments will be further defined in the Organizational Design process.

Market Operations	Forward Markets	Analyst (2)	▪ Basecase development
Market Operations	Forward Markets	Analyst (5)	▪ AFC/PUF calculation and posting ▪ IWR validation ▪ IWR auction & posting
Information Technology	Market Systems	Analyst (2)	▪ Application support
Information Technology	Market Systems	Analyst (1)	▪ Database support

12.0 COST DRIVERS

We have already identified some of the cost drivers that would impact the set up and operation of the RCS for Grid West. A preliminary list of such cost drivers include:

- System Redundancy: Redundant systems improve market response; however, they can be costly. For market solutions such as RCS, one could use cold standby and non-clustered solution to reduce cost. No redundancy should be required for the Secondary (fail-over) site of the RCS operation. In addition, ASP or outsourcing services for some systems can further reduce startup and potentially ongoing costs. Data redundancy can also be provided in a cold stand-by mode so far as near-synchronous data replication is in place between primary and backup system in the Primary site and to the system in the Secondary site.
- Staff Redundancy: Staff redundancy ensures smooth and long-term operation of RCS. Redundancy of staff can be minimized if timing of various RCS auction functions is planned to ensure that same resources can cover multiple functions.
- RCS Operation Timing: Limiting the time of RCS to business hours on weekdays will reduce resource (staff and applications and infrastructure) requirements and will help manage startup and ongoing costs.
- Complexity of Solution: A careful balance should be extended against rigor with which the application models are built and run and cost of attaining such a rigorous solution (that may still only be an approximation of the reality). For the RCS process, consistency is just as important as accuracy. One area for savings is the use of DC versus AC power flow based solutions for RCS auctions.
- Market Monitoring: The more extensive the market monitoring scope, especially the scope of after-the-fact surveillance, the higher the cost of the underlying system. If the bulk of market monitoring is in the form of preventive and auditable market rules, less effort will be extended for market monitoring.
- Participants System Access: The more direct and high speed access into Grid West is provided to Transmission Customers, the more the infrastructure and application costs. Internet, once properly secured through straightforward measures, offers a very reliable and inexpensive access media for market participants in the RCS auction.

- Multi-purpose System Use: Various RCS processes (A-RCS, M-RCS, I-OCS and DA-RCS) can use the same system and staff resources. In order to achieve this goal, it is imperative that the timing of various RCS auctions be carefully aligned so that the same resources can be used for all RCS auctions. Table 12 presents one such timing arrangement.

Table 11 - RCS execution time

RCS Timeline	Run Date	Run Date
Annual RCS	Once a year (non-Friday weekday in June)	2-5 PM (potentially repeated multiple times)
Monthly RCS	Once a month (a non-Friday weekday in the last full week of the month)	11AM-1PM (potentially repeated multiple times)
Intra-monthly RCS	Daily on business days	9AM - 10AM
Day-ahead RCS	Daily on business days	7 AM - 8 AM

13.0 REMAINING ISSUES

- Pricing of existing scheduling flexibility (ESF): Further work is required to determine whether an ESF can be released into DA-RCS along with a price offer versus as a price taker - as it is the case in the examples presented here.
- Calculation of adjusted CETRs due to each RCS auction is not a simple linear process and needs careful examination

Appendix A - EXAMPLE OF RCS

In this appendix, we will present a simple end-to-end example that covers the principal functions of the RCS process. This example is applicable to A-RCS, M-RCS and I-RCS. The example of DA-RCS is presented in Appendix B. All of these examples assume that the reader has a basic acquaintance with the calculation of power flows in a simple network. For non-technical readers unfamiliar with such calculations, Appendix C has been provided as an introduction to the basic concepts used. Non-technical readers may find it beneficial to read Appendix C before reading the other two appendices.

Pre-Auction:

Figure A-a shows a threebus system with three equal impedance transmission flowgates (paths). The Total Flow Capacity (TFC) is also shown on each flowgate.

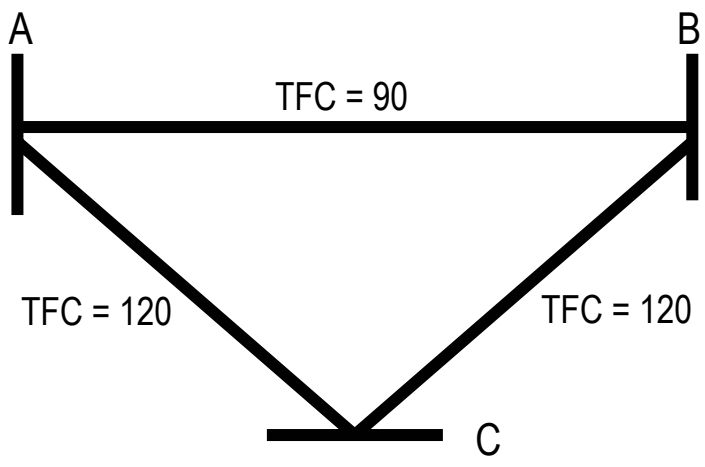


Figure A-a - Transmission Rights Basecase

Let's assume that these are three existing transmission rights (ETRs)[37] - all are point to point:

- ETR1: 60 MW from bus A to bus C
- ETR2: 60 MW from bus C to bus B
- ETR3: 60 MW from bus A to bus B

Now let's assume that ETR3 has been voluntarily translated by its owner into an IWR of the same magnitude from bus A to bus B. Also let's also assume that 30 MW of the translated IWR has been sold in a previous RCS process.

[37] For the purpose of these examples we have interchangeably used ETRs and TO obligations.

Step 1 of the AFC calculation process involves simulating non-translated existing rights ETR1 and ETR2 and the non-traded portion of ETR3 as shown in Figure A-b.

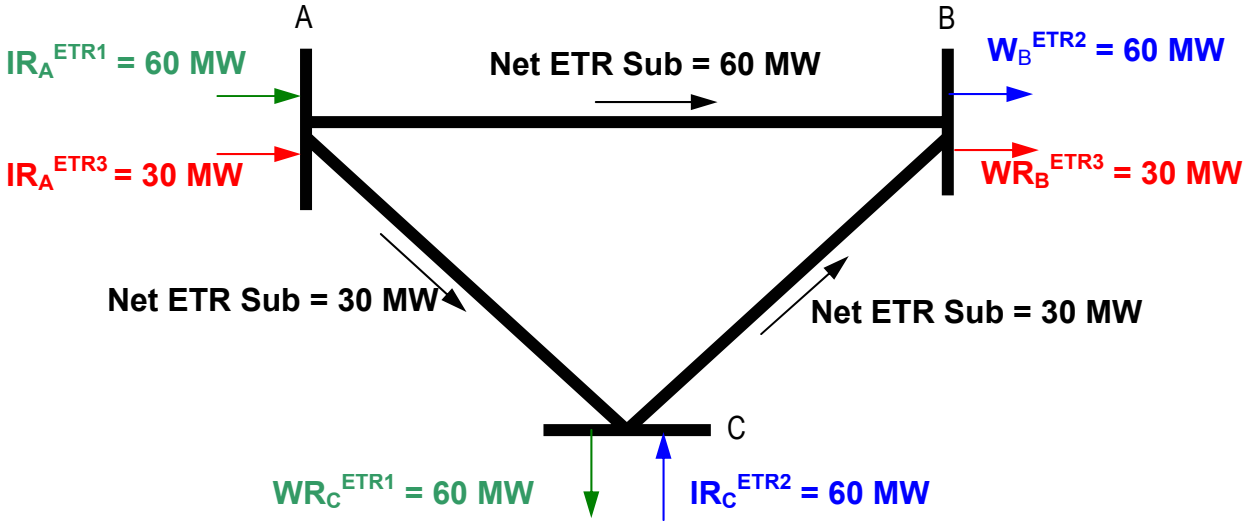


Figure A-b - ETR Flowgate Subscriptions

Table A-a presents the process of calculating AFCs using the methodology described in Section 4.2. In this and all subsequent tables "AFC^+" refers to AFC in the direction of the arrow shown and "AFC^-" refers to AFC in the opposite direction to the arrow. The same convention is used for subscriptions (Sub) in this and all subsequent figures.

Table A-a - AFC after accounting for ETRs

Flowgate	TFC in both directions	Net ETR Sub^+	AFC^+	AFC^-	X-Factor for AFC^+	AFC^+ after X-Factor	AFC^- after X-Factor
A - B	90 MW	60 MW	30 MW	90 MW	1.0	30 MW	90 MW
A - C	120 MW	30 MW	90 MW	120 MW	0.9	81 MW	120 MW
C - B	120 MW	30 MW	90 MW	120 MW	0.9	81 MW	120 MW

Step 2 in the calculation of AFCs involves accounting for traded, awarded or acquired IWRs (namely, all rights that have not been considered so far). Let's assume that in addition to the portion of ETR3 that had been traded as IWR (IWR1), there is another IWR (IWR2) from bus C to Bus B for 30 MW (acquired previously). The two new IWRs are

- IWR1: 30 MW from bus A to bus B
- IWR2: 30 MW from bus C to bus B

Figure A-c offers the IWRs and their flowgate usage. Note that in this figure the counterflow contribution of IWR2 on flowgate A-C has been ignored while all same direction flow

contributions are added up. Table A-b presents the process of calculating the final AFCs. Table A-c presents table of PUFs for this example.

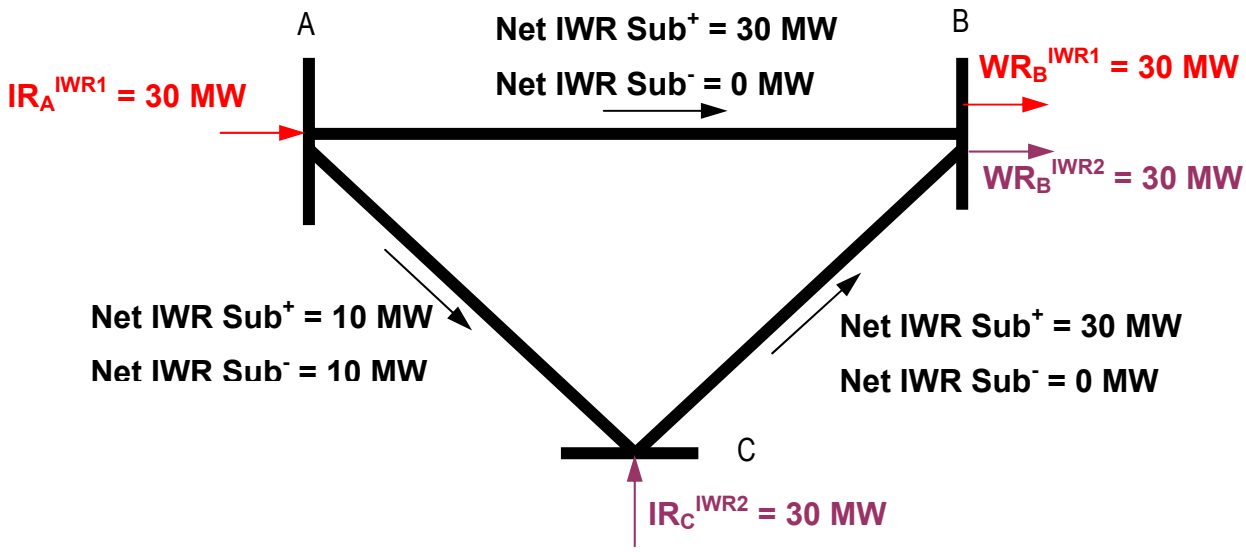


Figure Ac - IWR Flowgate Subscriptions

Table Ab - AFC after accounting for IWRs

Flowgate	AFC^+ before IWRs	AFC^- before IWRs	Net IWR Sub^+	Net IWR Sub^-	AFC^+ after IWRs	AFC^- after IWRs
A - B	30 MW	90 MW	30 MW	0 MW	0 MW	90 MW
A - C	81 MW	120 MW	10 MW	10 MW	71 MW	110 MW
C - B	81 MW	120 MW	30 MW	0 MW	51 MW	120 MW

Table A-c - PUFs for the example system (Bus C is the Reference/Slack Bus)

Flowgate	Bus A	Bus B	Bus C
A - B	1/3	-1/3	0
A - C	2/3	1/3	0
C - B	-1/3	-2/3	0

In Table A-c PUFs represent the flow contribution on a flowgate due to injection of 1 MW at a bus. For example, this table shows that if 1 MW is injected at Bus B, 1/3 of a MW will flow on Flowgate A-B in the opposite direction (from B to A), 1/3 MW will flow on Flowgate A-C and 2/3 MW will flow on Flowgate C-B in the opposite direction (from B to C) - please note that Bus C is the reference bus, i.e. every MW injected at Bus B ends up at Bus C. Table A-c helps with

predicting flow contribution due to an IWR. Suppose a Transmission Customer wants to buy 30 MW IWR from Bus A to Bus B. This participant calculates its contribution on every flowgate as follows:

- Flowgate A-B: 30 * [(1/3) - (-1/3)] = 20 MW
- Flowgate A-C: 30 * [(2/3) - (1/3)] = 10 MW
- Flowgate C-B: 30 * [(-1/3) - (-2/3)] = 10 MW

Auction Example 1:

Entering into the auction we assume that that there are two bidders for IWRs in the IWR auction:

- Bid1: 50 MW from bus A to bus B at $20/MW
- Bid2: 50 MW from bus C to bus B at $15/MW

Let's also assume that the owner of IWR1 offers the IWR as follows:

- IWR1 offer: 15 MW IWR as price taker

Figure A-d presents the network diagram for this bidding scenario. Please note that the arrows for the offered IWRs are reversed to show that they are offered for sale to free up capacity for new IWR buy bids. Also note that AFCs from the last round are included on the diagram.

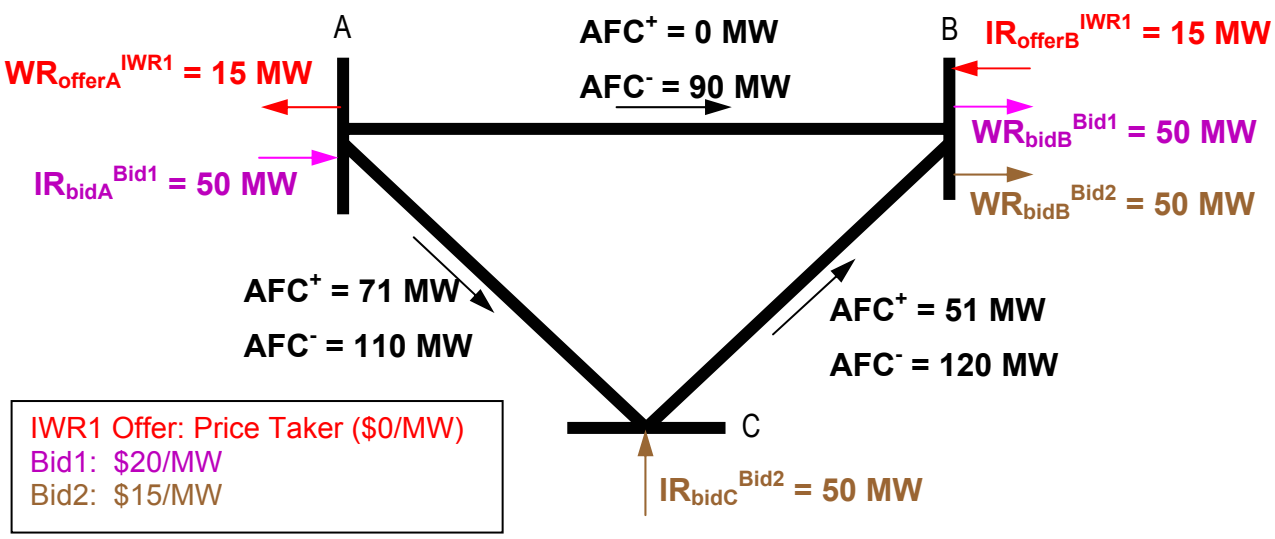


Figure A-d - IWR Auction Offers and Bids

Figure A-e presents the IWR auction results. The auction outcome has been attained based on maximizing the overall value of the IWR trades (total value of the bids minus the total cost of offers) which awards the offered IWRs to Bidder 2, even though Bidder 2 bid a lower per MW

price, since for every one MW of IWR1 offered, Bidder 2 can buy two MWs due to network configuration. For this auction award, the overall market value is:[38]

- 30 MW * $15/MW - 15 MW * $0/MW = $450

If Bidder 1 was selected, the overall market value would have only been:

- 15 MW * $20/MW - 15 MW * $0/MW = $300

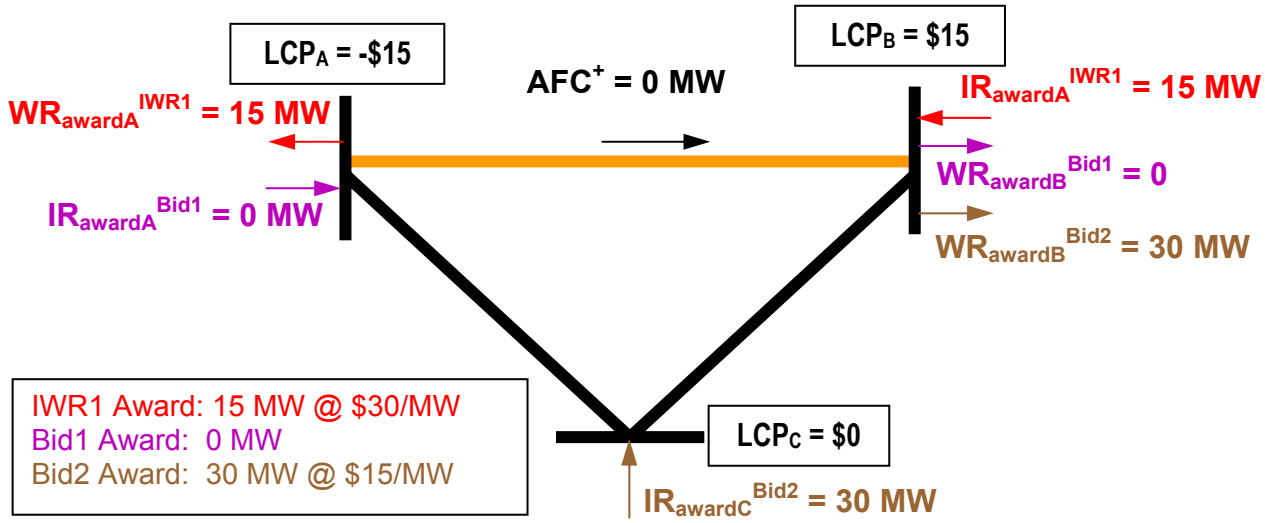


Figure A-e - IWR Auction Results

In this example Bid2 is at margin and sets clearing prices at all buses. Please note that the negative clearing price at Bus A is a result of setting the reference price bus at zero. The negative price does not signify anything in an IWR auction, as only the differences in bus clearing prices are meaningful in such an auction.

Table A-d presents the settlement amounts. Please note that in this scenario although the value trades is $450, Grid West will be revenue neutral (difference of the awarded IWR charges and awarded IWR credits).

Table A-d - IWR auction awards and settlement results

Participant	Award Amount	IWR Price	Charge or (Credit)
IWR1	15 MW	$30/MW	($450)
Bidder 1	0	0	0
Bidder 2	30 MW	$15/MW	$450

[38] Note that market value calculation and actual settlements calculations are two completely separate processes. Auction value simply determines who is awarded in the auction based on their offer and bid prices.

Auction Example 2:

In this example let's assume that the owner of IWR2 offers the IWR as follows:

- IWR1 offer: 30 MW IWR as price taker

Figure A-f presents the network diagram for this bidding scenario.

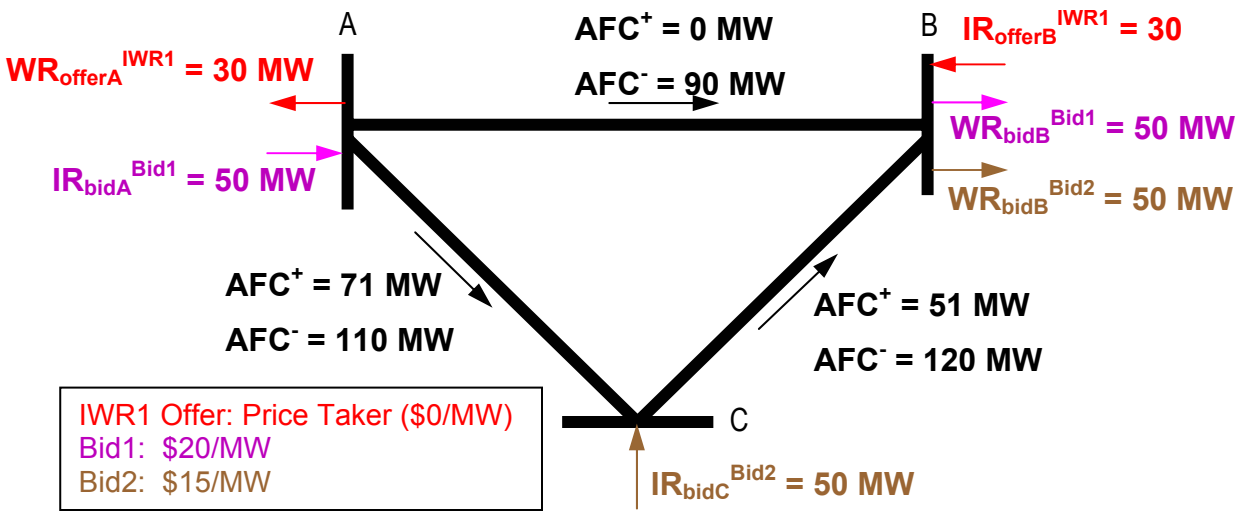


Figure A-f - IWR Auction Offers and Bids

Figure A-g presents the IWR auction results. The auction outcome has been attained based on maximizing the overall value of the IWR trades (total value of the bids minus the total cost of offers). In this example Bid1 is at margin and sets the clearing prices at all buses.

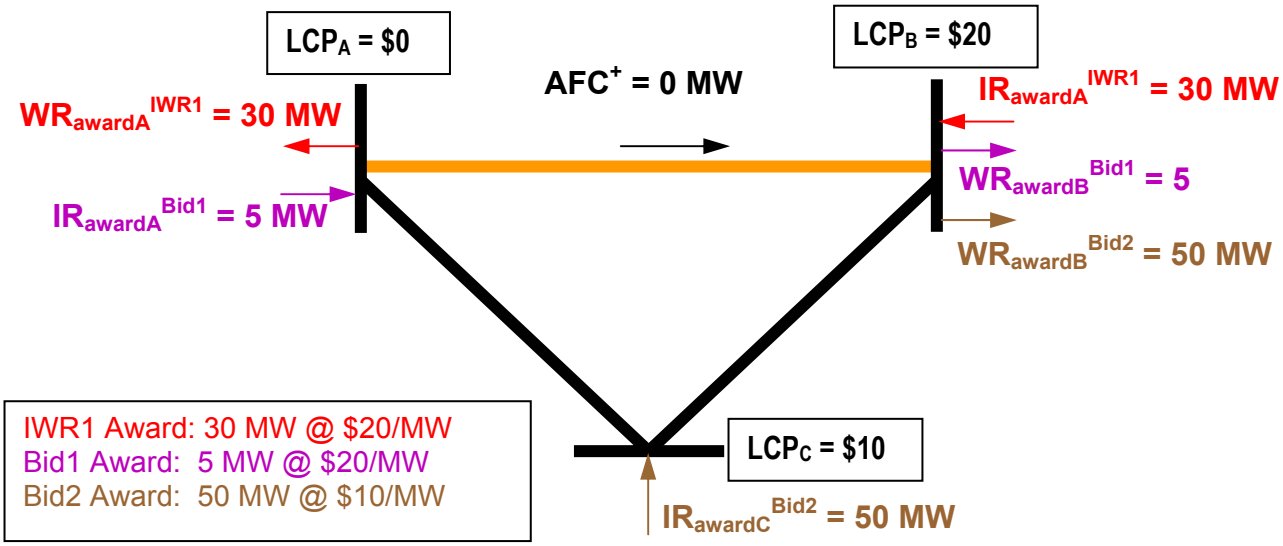


Figure A-g - IWR Auction Results

Table A-e presents the settlement results for this example.

Table A-e - IWR auction awards and settlement results

Participant	Award Amount	IWR Price	Charge or (Credit)
IWR1	30 MW	$20/MW	($600)
Bidder 1	5 MW	$20/MW	$100
Bidder 2	50 MW	$10/MW	$500

Appendix B - EXAMPLE OF DA-RCS

In this appendix we will present a simple end-to-end example that covers the principal functions of the DA-RCS process. As noted earlier the many of the steps in DA-RCS process are distinct from those of other RCS processes.

Pre-Auction:

Figure B-a shows a three-bus system that will be used to present the example of DA-RCS. Total Flowgate Capacities (TFCs) are also shown in this figure.

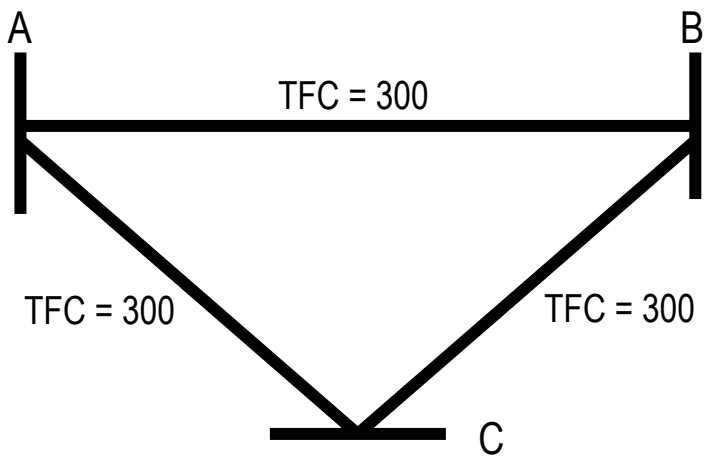


Figure B-a - Transmission Rights Basecase

Let's assume that these is one multipoint-to-multipoint ETR, with existing scheduling flexibility (ESF) as shown, and one IWR in this system - Figure B-b:

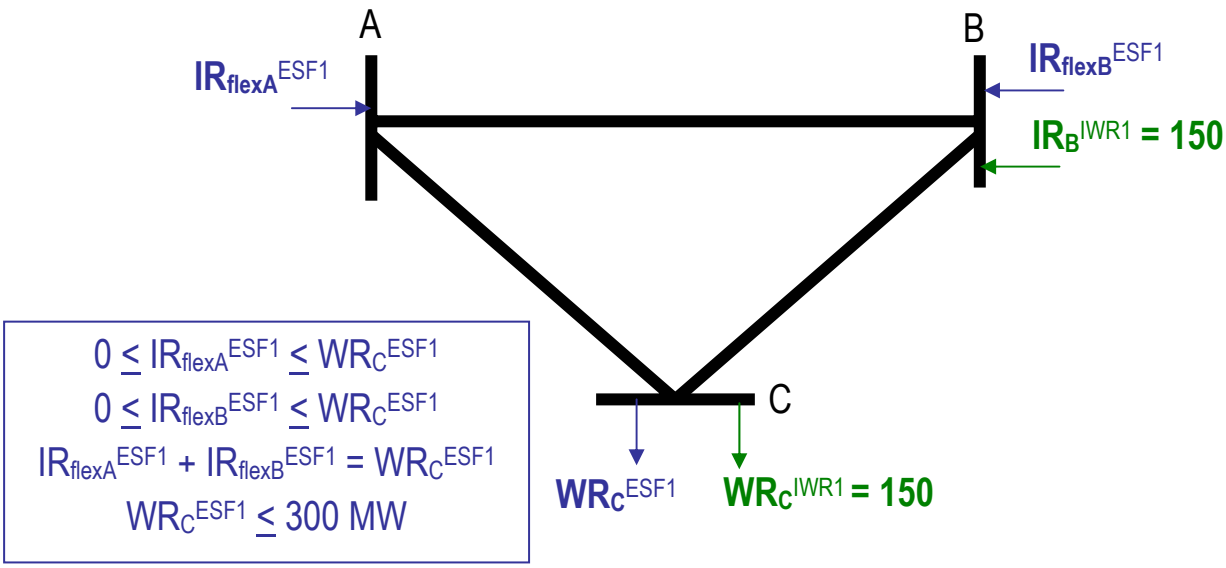


Figure B-a - Existing Rights Configuration

Table B-a presents the process of calculating AFCs for DA-RCS. As described in Section 4.6, for DA-RCS:

- The entire scheduling flexibility is taken into consideration in evaluating flowgate subscription due to an ESFs;
- Counterflows due to ETRs and IWRs are allowed; and
- AFCs are modified based on X-factors after subscriptions are netted out.

Table B-a - AFC calculation for DA-RCS

Flowgate	TFC (MW)	Net Sub by ESF/IWR (MW)		AFC Before X (MW)		X-factor	AFC after X (MW)	
		+	-	+	-		+	-
A-B	300	50	-50	250	300	0.9	225	270
A-C	300	250	0	50	300	1.0	50	300
B-C	300	300	0	0	300	1.0	**Zero(0)**	300

Note that based on this right configuration, there is no AFC on flowgate B-C from B to C; hence, no new rights can be awarded (issued) based on AFCs in the system.

Auction:

Entering into the DA-RCS auction, we assume that the ESF holder offers to release its flexibility as a price taker and IWR2 is a new bid to buy capacity as shown in Figure B-b below. In this figure ESF holder submits an intended retained right configuration will less flexibility than the original right allowed and as such releases the extra flexibility into DA-RCS auction. IWR1 maintains its position unchanged.

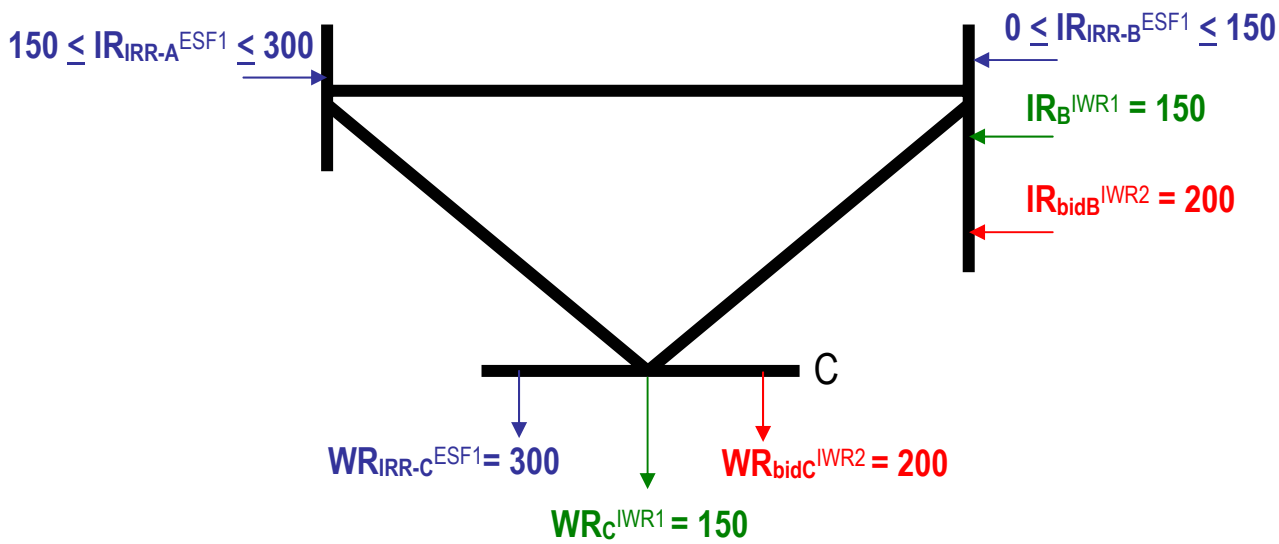


Figure B-b - DA-RCS IWR Auction Offers and Bids

Table B-b presents the AFCs before the auction and after ESF1 holder has offered some of its flexibility.

Table B-b - AFCs after ESF1 holder offered some of its flexibility

Flowgate	TFC (MW)	Net Sub by ESF/IWR (MW)		AFC Before X (MW)		X-factor	AFC after X (MW)	
		+	-	+	-		+	-
A-B	300	50	50	250	250	0.9	225	225
A-C	300	250	0	50	300	1.0	50	300
B-C	300	250	0	50	300	1.0	**50**	300

Note that due to ESF1 flexibility offer, Flowgate B-C's AFC increases from zero to 50 MW. During the auction this 50 MW AFC is used to award 75 MW to IWR2 as shown in Figure B-c, which contains the auction outcome.

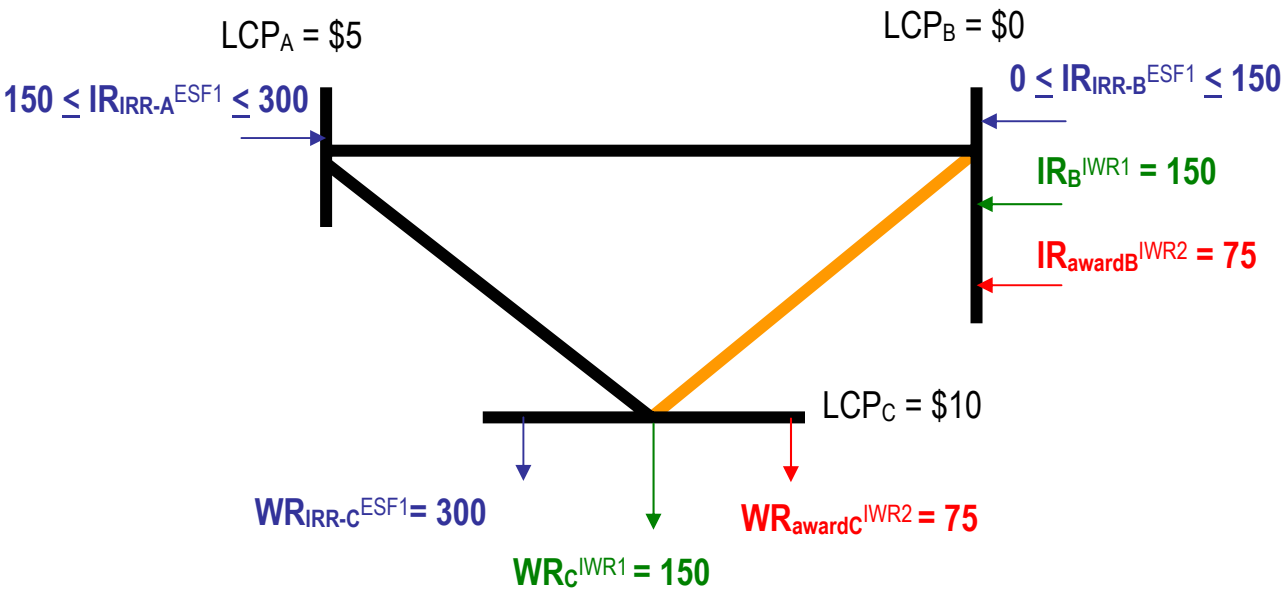


Figure B-c - IWR Auction Results

In this example IWR2 is at margin and sets clearing prices at all buses.

The settlement results are presented in the following:

- IWR2 pays: 75 * ($10 - $0) = $750
- ESF1 receives: 50 * $15 = $750

Note that ESF1 holder is paid based on the value of the 50MW AFC that it has released into DA-RCS - product of released AFC on B-C flowgate (50 MW) and the shadow price of that flowgate ($15/MW).

Appendix C – AN INTRODUCTIOIN TO THE CALCULATION OF POWER FLOWS FOR THE NON-TECHNICAL READER

In the examples given in Appendices A and B, simple three-bus (node) networks are used. The Appendix demonstrates how the power flows may be calculated for these simple networks. This material is provided to assist non-technical readers of the white paper in understanding the flow shown in the examples for various injections and withdrawals.

In an electrical network, the flow on any given line, due to the injection of power at one point and a matching withdrawal of power at another point, is based on that given line's relative impedance[39] compared to the impedance of other lines. The simplest case for illustrating this principle is shown in Figure C-a, which has only two buses A and C and two parallel lines between these buses. The impedance of Line 2 is twice that of Line 1, so Line 1 will carry twice the power flow of Line 2.[40]

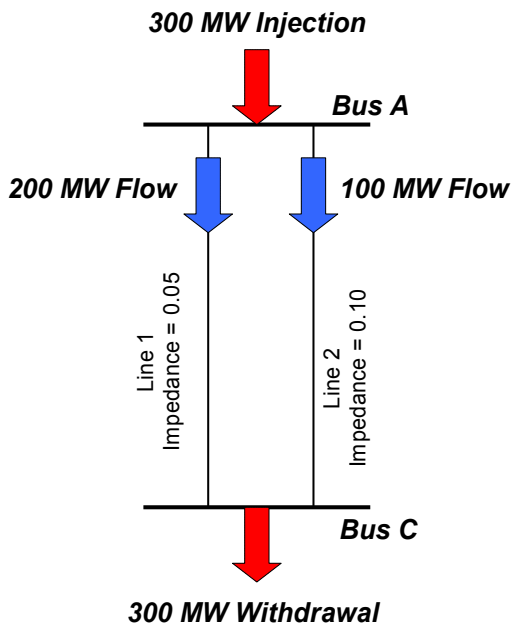


Figure C-a – A Two Bus Model

[39] Impedance is a general term used to describe the opposition of a line operating in an AC network to a change in power flow.

[40] Based on laws of physics, also known as the Ohms Law, lower impedance for a line means that more power flow will go through that line with the magnitude of the flow proportional to the inverse of the impedance. This is analogous to having a pair of pipes connected to a common water source with one pipe having twice the cross sectional area of the other pipe. In this water analogy, the larger pipe has the half the impedance of the other pipe and therefore admits twice as much water. Path Utilization Factors (PUFs) essentially give the same information. They show how an injection at a bus will flow on a line based on the impedance of that line compared to impedances of all lines in the system.

If we take Line 2, cut it in half and add another bus B at the cut and then reconnect the system, the result in shown in Figure C-b.

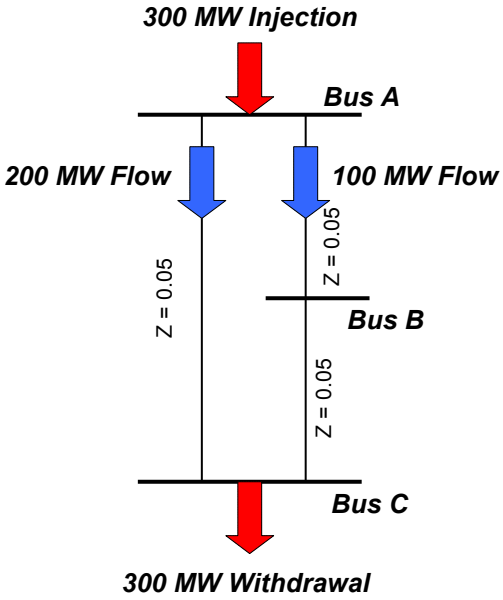


Figure C-b – Adding Another Bus

What was Line 2 in Figure C-a is now divided into Lines A-B and B-C, while Line 1 is now called Line A-C. The impedance (Z) of each of the lines is shown in Figure C-b. Line A-B and Line B-C each have half of the impedance of Line 2 since they are each one half of that line. Because these two line segments are in series with each other, line impedances add together to give the resultant impedance for the combination of lines A-B and B-C. The resulting relative impedance of Line A-C to the rest of the system is unchanged, so the distribution of power flows is unchanged. Note that with the addition of Bus B, all the line segments have the same impedance, Z = 0.05. We can redraw the diagram as shown in Figure C-c.

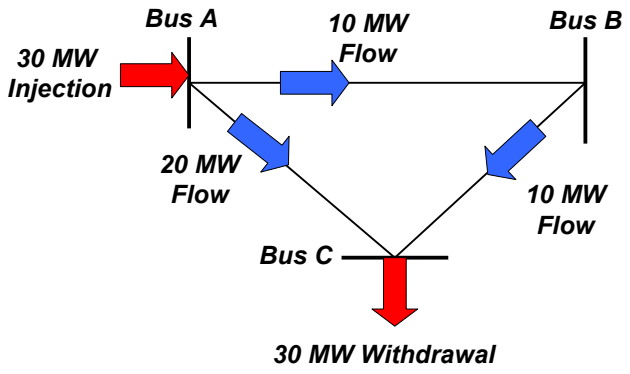


Figure C-c – A Three Bus Model

Although the impedances are no longer shown in Figure C-c, they remain the same for each segment, i.e., Z = 0.05. The flows are unchanged, only the shape of the drawing is changed. Figure C-c is now in the form used for all the three bus models in Appendices A and B above, with equal impedance in each line segment. Now suppose that instead of injecting power at Bus A, we decide to inject power at Bus B instead and at the same time change the injection to 60 MW. The result is shown in Figure C-d.

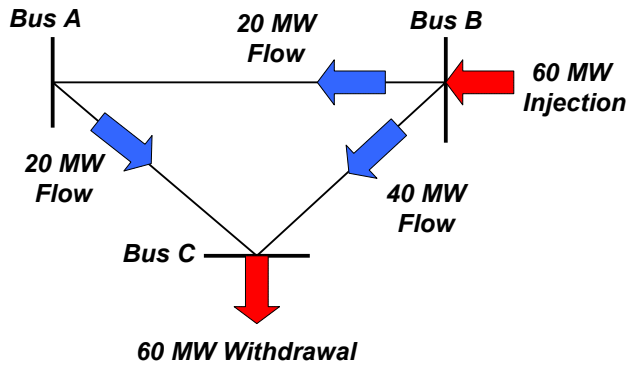


Figure C-d – Changing the Injections and Withdrawals

Again the impedance of the lines from B-A and A-C add together to give Z = 0.10, or twice the impedance of line B-C. The result will be twice as much flow on line B-C, so again the flows split on a one-third to two-thirds basis, with 40 MW on the line with lower impedance and 20 MW on the other line.

Now suppose you want to add both transactions at the same time – that is transfer 30 MW from Bus A to Bus C and 60 MW from Bus B to Bus C - equivalent to 30 injection at Bus A, 60 MW injection at Bus B and a 90 MW withdrawal at Bus C. For simple models like those used for this paper's illustrations, the principle of superposition applies – that is the solution show in

Figure C-c and Figures C-d can be "superimposed" on each other oradded together to get a net result.

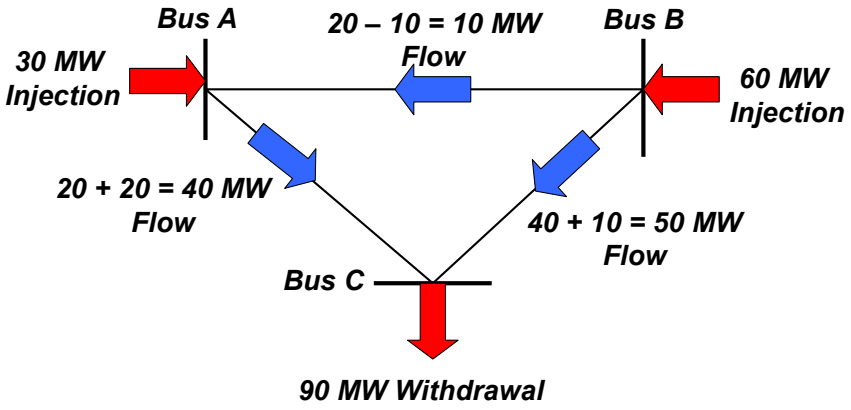


Figure C-e – Multiple Injections at Different Buses

The additive nature of the flows is shown in Figure C-e above on lines A-C and B-C. For instance, the flow on line B-C in Figure C-c was 40 MW for 60 MW injected at B and withdrawn at C. The flow on line B-C was 10 MW for the 30 MW injected at Bus A and withdrawn at Bus C. Because we can add the two individual cases, we get 40 + 10 = 50 MW for the combined case. The use of the superposition principle allows the solution of simpler problems that can then be added together to get to the net result.[41]

Another important principle is show in Figure C-e, namely, that all the flows into and out of any given bus must be zero. For instance at Bus A, there is a net 10 MW flowing in from Bus B, 30 MW is injected by generation, so 40 MW flows out toward Bus C. If we give a negative sign to out flow, then 10 + 30 – 40 = 0.

In the illustrations of the principles of transmission right reconfiguration in Appendices A and B, the injection and withdrawal rights are treated as physical injections and flow result can be computed as show above. Because the impedances are equal for all the line segments in the papers examples, one thirdof an injection will take the "long route" and two thirdswill take the "short route" for the reasons described above.

[41] The assumption of linearity for an AC network is reasonable for normal operating conditions.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY AND CONCLUSIONS

The proposed design for Grid West services emphasizes physical power transactions among its Transmission Customers by making transmission capacity available to Grid West Transmission Customers. The Transmission Service Liaison Group (TSLG) has focused on developing processes to maximize access to the Grid West Managed Transmission System (GWMT) through the acquisition of transmission rights. The Reconfiguration Service (RCS) has been proposed to serve this purpose. Specifically, the RCS makes transmission capacity available through: a) existing Available Flow Capacity (AFC); b) voluntary resale of existing transmission rights; and c) the voluntary sale of existing scheduling flexibility.[1]

A Redispatch Service (RDS) was included in the Regional Proposal[2] as a basic feature of Grid West. The purpose of RDS was to enable greater use of the transmission system by obtaining advanced scheduling commitments. During the initial design work (Layer 1), difficulties were encountered in attempting to design the RDS. Two primary difficulties were identified, appearing to have the potential for creating severe market gaming opportunities.[3]

- First, since participation in RDS would be voluntary, only some schedules would be (financially) constrained by the day-ahead redispatch. However, because not all parties would be constrained to a day-ahead schedule, the congestion optimization achieved by the day-ahead redispatch could be undone by parties who retain and use their pre-existing scheduling flexibility after the day-ahead process ends.
- Second, measurement of performance would be problematic. A voluntary day-ahead redispatch is a partial energy market. Deviations from day-ahead energy schedules must be settled against real-time energy

[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.

[2] "Narrative Description of RRG Platform Group Regional Proposal", December 24, 2003, pp. 7-8, http://gridwest.org/Doc/FinalNarrative_RegionalProposal_Dec242003.pdf. The Regional Proposal described an Independent Entity (IE) that has since been given the name Grid West.

[3] This type of bilateral transmission trade facilitates the surplus power market, especially in the shorter term. Older transmission instruments still in place, and older transmission contracts offered by the Transmission Owners are typically not tradable on the secondary market as there are no resale rights associated with these contracts.

deliveries. However, since not all participants in the day-ahead redispatch would be subject to a single set of prices of real-time balancing energy prices, how would reconciliation occur? Some parties would be in the CCA where a set of consistent real-time clearing prices would apply, while prices outside the CCA would have to be based on OATT tariff concepts or some other price indicators.

When the day-ahead redispatch issue was revisited by TSLG at the start of the next phase of design (Layer 2), RCS was better understood than during the Layer 1 discussion of RDS. In reviewing the intended purposes of the RDS, it became clear that one of the desired effects (getting parties to release a portion of their scheduling flexibility, i.e. commit to a generation plan day-ahead) could be accomplished through the Day Ahead Reconfiguration Service (DA-RCS). If parties with scheduling flexibilities (generation operators, transmission rights holders with various delivery points, etc.) could limit or give up their scheduling flexibility in DA-RCS, the "headspace"[4] set aside to preserve pre-existing rights would be reduced. That reduced "headspace" becomes AFC that can be sold as Injection-Withdrawal Rights (IWRs) in DA-RCS. Thus, by enhancing the DA-RCS to handle releases of scheduling flexibility, Grid West would realize a major portion of the RDS benefit while avoiding many of the RDS complications mentioned above. In other words, through this proposal, DA-RCS achieves an important RDS objective, namely making more transmission system capacity available through voluntary offers to restrict changes in generation for the following day.

With this modification, the typical day for pre-scheduling in Grid West fits easily into the general pattern of pre-scheduling used today. Trades for the next day occur very early in the morning followed by calls to various transmission providers to find out if transmission can be found to execute the trades. With this done, pre-schedules are submitted to the transmission providers. The DA-RCS replaces the calls to find transmission with a central auction where AFC is more readily available through a single centralized process that includes pre-release AFC, AFC made available by IWR releases, and AFC freed up by releases of scheduling flexibility.

[4] Headspace is a term used to describe the capacity set aside prior to an RCS auction to preserve pre-existing rights, including the scheduling flexibility (or optionality) of generators and transmission rights holders to change their schedules after the close of the day-ahead scheduling process.

1.0 EXECUTIVE SUMMARY

Grid West Basic Features should not adversely impact existing bilateral trading practices within the Grid West Managed Transmission (GWMT) system.[1]

2.0 BACKGROUND

Bilateral trading refers to transactions not administered by Grid West in which wholesale energy, transmission rights and reserves are directly traded among Grid West Transmission Customers. Parties in the GWMT engage in a variety of bilateral trades of wholesale energy, transmission rights and reserves. Energy is typically sold for forward quarters, months, balance of the month, daily, and the period between close of pre-schedule and hour of delivery. These trades are important to improve the efficiency of the overall power market and provide the primary opportunity for parties who are either long or short to balance their positions on a forward basis.

Bilateral secondary transmission trades occur most frequently on BPA's system. Point-To-Point (PTP) capacity is sold bilaterally in several ways:

- Non-firm blind assignments
- Firm assignments
- Firm redirects

These trades are ways for holders of PTP to recoup some of their sunk PTP costs and are typically sold at a discount from the originally posted price. For secondary buyers, these trades are often available when there is no Available Transmission Capacity (ATC) on a transmission provider's system, where they are less expensive than buying the capacity directly from the provider, and when they are easier to transact than going to the transmission provider's Open Access Sametime Information System (OASIS). This type of bilateral transmission trade facilitates the surplus power market, especially in the shorter term. Older transmission instruments still in place (such as BPA's Integrated Resource Transmission Service and Formula Power Transmission Service, and older transmission contracts offered by the Transmission Owners are typically not tradable on the secondary market as there are no resale rights associated with these contracts. The formation of Grid West should not hinder the existing bilateral market for power and transmission.

[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.

Grid West will centrally administer Available Flowgate Capacity (AFC), so Transmission Owners will no longer issue new transmission rights. Load Serving Entities will continue to have the option to procure the necessary long-term transmission to move energy and related commodities from long-term resources to their load centers. Bilateral trading of existing rights will continue to be possible under Grid West to the extent allowed under relevant contracts.

3.0 PURPOSE

The purpose of this paper is to qualitatively analyze the impact of Grid West services on bilateral trading activities within the GWMT.[2]

4.0 IMPACT OF GRID WEST SERVICES ON BILATERAL MARKETS

The following Grid West services were evaluated:

- Long-term regional expansion planning service
- Transmission access administration
- Reconfiguration service
- Regional scheduling service
- CCA Real-time balancing service
- CCA Reserve market

Grid West Basic Features should not adversely impact existing bilateral trading within Grid West, but should enhance such trading activities by offering price transparency and other mechanisms encouraging such trades to take place.[3] Grid West will administer Available Flowgate Capacity (AFC), so Transmission Owners will no longer issue new transmission rights. Bilateral trading of existing rights will continue under Grid West to the extent allowed under relevant contracts. Participants may find it easier, and potentially more beneficial, to translate such rights into IWRs before trading them either bilaterally or in centrally administered markets.

[2] In this white paper we focus on economic and technical dimensions of bilateral trading practices and will not address the regulatory jurisdiction and rules that govern bilateral trading within the GWMT and whether or how these regulatory factors will play any role in the evolution of these markets.

[3] This is also in line with the general understanding that all factors that fundamentally discourage centralized administered markets can also discourage bilateral markets and vice versa.

4.1 Wholesale Energy

Grid West will introduce a number of centrally administered markets and services to facilitate the trading of wholesale energy, transmission rights and reserves. These markets should help promote bilateral trading within Grid West through the production of stable reference prices.[4] Grid West's centrally administered markets will produce such reference prices if they are sufficiently liquid. Table 4.1 qualitatively analyzes the impact of Grid West Basic Features on bilateral trading.

Table 4.1 - Impact of Grid West on Bilateral Wholesale Energy Trading

Grid West Service	Impact on Bilateral Wholesale Energy Trading
Regional Planning & Capacity Expansion Service	Grid West will provide a transmission and capacity expansion service[5]. Projects proposed by Transmission Owners or other Transmission Customers will be evaluated considering the needs of the entire GWMT. The completion of expansion projects will allow for more energy transactions between energy suppliers and customers. Regional capacity planning and capacity expansion service by Grid West is expected to facilitate the development of new energy resources that in turn should promote additional bilateral trading of wholesale energy.
Transmission Access Administration	Grid West will administer transmission access, making it easier for new and existing energy resources to reach energy customers across the entire GWMT and enhancing the volume of bilateral wholesale energy trades.[6]
Reconfiguration Service (RCS)	Reconfiguration services provide wholesale energy traders with additional transmission information (e.g., reference prices), and the additional and standardized means (IWRs) to acquire long-term and short-term transmission rights to be used for bilateral wholesale energy trading. Voluntary release of scheduling flexibility as part of D-

[4] There are numerous examples of how reliable reference prices for any commodity have led to a rapid rise in the volume of bilateral (whether OTC or exchange facilitated) trading of that commodity - please see http://www.nordpool.com for the example of energy trading growth.
[5] See the accompanying Grid West White Paper on Regional Planning and Capacity Expansion service - to be released.
[6] It is understood that access will only be granted with due consideration for all relevant reliability requirements for GWT, studied jointly by Grid West and PTOs, including determination of all the necessary system upgrades to deal with such reliability requirements.

	RCS will free up additional transmission capacity just before the DA scheduling process and allow Grid West Transmission Customers to acquire additional IWRs to facilitate additional bilateral whole energy transactions.
Region-wide Scheduling Service	Region-wide scheduling services, including the operation of a public market information site (e.g., OASIS), provide Transmission Customers with valuable information about transmission availability, resulting in better regional coordination of transmission resources. This should further facilitate the bilateral trading of wholesale energy.
CCA Real-time Balancing Service (RBS)	RBS provides another forum for bilaterally traded wholesale energy to be sold, and hence, Grid West's RBS should enhance bilateral trading of wholesale energy.
CCA Reserve Market Service	The reserve market should have neither a negative impact nor an identifiable positive impact on bilateral wholesale energy trading.

4.2 Transmission Rights

Grid West will issue standardized tradable instruments (IWRs) used in both central and bilateral markets for trading transmission rights. These new products and the development of reference prices (and price discovery) should positively impact the bilateral trading of transmission rights. Table 4.2 is intended to qualitatively analyze the impact of Grid West Basic Features on bilateral transmission rights trading within Grid West.

Table 4.2 - Impact of Grid West on Bilateral Transmission Rights Trading

Grid West Service	Impact on Bilateral Transmission Rights Trading
Regional Planning & Capacity Expansion Service	Grid West issues transmission rights created by new transmission projects as IWRs.[7] Thus, new transmission projects make additional IWRs available for both RCS and bilateral markets to trade. Grid West centrally administers long-term requests for AFC, with rights issued as IWRs.
Transmission Access Administration	Administration of transmission access by Grid West should make it easier to access the transmission system on a regional basis. As a result, it is expected to increase the demand for transmission rights (IWRs), which in turn

[7] The process of translating new transmission projects into IWR will also involve PTOs and WECC and is presented in the accompanying on rights data management.

	should increase the volume of transmission rights trades both in bilateral and centrally administered markets.
Reconfiguration Service (RCS)	Creation of readily tradable instruments and contracts for transmission rights (IWRs) will allow bilateral trading of transmission rights to be more easily managed in the Over the Counter (OTC) and exchange-based markets, likely leading to increased bilaterally traded transmission rights (IWRs). Reconfiguration service along with RDS creates reliable reference prices (and price discovery) for IWRs, which are expected to also promote bilateral markets for transmission rights (IWRs). Reconfiguration service allows IWRs acquired through various mechanisms such as bilateral trades to be centrally auctioned, or vice versa. Hence, RCS is expected to enhance bilateral trading of transmission rights (IWRs). Short-term use of AFC is centrally administered by Grid West with the Reconfiguration Service enabling transmission users to combine AFC with releases enabled translation of existing rights and the reconfiguration auctions. Direct requests for AFC from Transmission Owners will not be possible once Grid West takes over capacity management of transmission facilities. Voluntary release of scheduling flexibility as part of D-RCS will free up additional transmission capacity just before the DA scheduling process and allow Grid West Transmission Customers to acquire additional IWRs. These IWRs may be bilaterally traded between D-DCS and the deadline of IWR registration with Grid West.
Region-wide Scheduling Service	Region-wide scheduling services, including the operation of a public market information site (e.g., OASIS), provides Transmission Customers with valuable information about transmission availability resulting in better regional coordination of transmission resources. These outcomes should further facilitate the bilateral trading of transmission rights.
CCA Real-time (RT) Market Operations	No impact.
CCA Reserve Market Operations	Participants located outside the CCA who wish to participate in the CCA Reserve Market may need to acquire the appropriate transmission rights if they wish to offer resources into a reserve zone in which they are not located. This should promote bilateral trading of

	transmission rights.

4.3 Reserves

Grid West services, specifically the CCA reserve auction market, should enhance bilateral reserve markets within Grid West. Table 4.3 qualitatively analyzes the impact of Grid West Basic Features on the bilateral trading of reserves within Grid West.

Table 4.3 - Impact of Grid West on Bilateral Reserve Trading

Grid West Service	Impact on Bilateral Reserve Trading
Regional Planning & Capacity Expansion Service	No significant direct impacts on bilateral reserve trading are expected here. Secondary impacts can be observed due to additional and accelerated development of new energy resources brought about due to long-term regional expansion planning service of Grid West.
Transmission Access Administration	Resources out of the CCA can access transmission system in a more straightforward manner due to transmission access administration by Grid West and, hence, should be able to bilaterally offer their reserve capacity to CCA utilities when transmission is required.
Reconfiguration Service (RCS)	Reconfiguration service should allow resources outside CCA to acquire IWRs giving them the ability to bilaterally offer their reserve capacity to CCA utilities (when transmission is required).
Redispatch Service (RDS), if and when implemented	Redispatch service should not directly impact bilateral reserve trading within GWMT.
Region-wide Scheduling Service	Region-wide scheduling services, including the operation of a public market information site (e.g., OASIS), provides valuable information about reserve requirements and transmission availability to all Grid West Transmission Customers (and beyond) resulting in better coordination of reserve acquisition and transmission resources use on a regional level. These outcomes are expected to further facilitate the bilateral trading of reserves.
CCA Real-time (RT) Market Operations	CCA RT market operation is not expected to directly impact bilateral reserve trading within GWMT.
CCA Reserve Market Operations	The CCA reserve market should significantly increase bilateral trading of reserve products. A potential CCA limited must offer reserve obligation would directly

	promote bilateral trading of reserves as Grid West Transmission Customers who are short on reserve capacity will seek to contract for such reserves bilaterally in order to satisfy their obligations.

5.0 PARTICIPATION IN BILATERAL TRADING AND ROLES & RESPONSIBILITIES

Table 5.1 presents the three bilateral trading activities that are expected within the GWMT and the roles that various Grid West Transmission Customers directly play in each of these activities.

Table 5.1 - Grid West Transmission Customer's Role in Bilateral Trading

Bilateral Markets	Grid West	Transmission Owners	Transmission Customers
Bilateral Wholesale Energy Trading	▪ None	▪ None	▪ Buy/sell wholesale energy bilaterally
Bilateral Transmission Rights Trading	▪ Register and confirm bilaterally traded IWRs	▪ None for IWRs. ▪ ETRs reassignments, if requested under original contract or tariff provisions, may require TO involvement.	▪ Buy/sell transmission rights bilaterally
Bilateral Reserve Trading	▪ None	▪ None.	▪ Buy/sell reserve bilaterally

6.0 MARKET BENCHMARKS

Except for the recent credit problems that have resulted in migration of bilateral energy trading volumes into the RTO/ISO administered markets, bilateral markets are functioning within existing RTOs and ISOs. Table 6.1 provides benchmarks of existing RTO/ISO bilateral markets.

Table 6.1 - Bilateral Trading Benchmarks

Timing	PJM	ERCOT	MISO
Bilateral Wholesale Energy Trading	▪ Bilateral energy trading increased in PJM after PJM launched its markets and published reference prices for	▪ Since ERCOT has opened its market for retail competition and because ERCOT does not have a Day-Ahead energy market, the volume of bilateral	▪ No relevant experience for MISO yet.

	energy at its major hubs. ▪ Recent dips in these bilateral energy market volumes in favor of increase in the volume of PJM markets reflect credit concerns in the bilateral markets.	energy trading in ERCOT has increased significantly since the operation of ERCOT ISO started. ▪ Recent dips in these bilateral energy market volumes in favor of the ERCOT RT market reflect credit concerns in the bilateral markets.	
Bilateral Transmission Rights Trading	▪ Bilateral trading of transmission rights in PJM, ERCOT and MISO is limited to standardized financial transmission rights (FTRs for PJM and MISO and TCRs for ERCOT). Existing rights cannot be bilaterally traded. Grid West will continue to allow bilateral trading of existing rights when allowed in relevant contracts. ▪ Compared to existing RTOs and ISOs, Grid West has a unique requirement that scheduling can only be done consistent with relevant physical transmission rights. This requirement is expected to make overall (including bilateral) trading of transmission rights significantly more active within GWMT compared to existing RTOs.		
Bilateral Reserve Trading	▪ PJM and ERCOT allow self-scheduling of reserves, which has contributed to a healthy bilateral market for reserves in their footprints. Grid West CCA's potential limited must offer obligation for reserves is expected to achieve the same outcome.		▪ No relevant experience for MISO yet.

1.0 EXECUTIVE SUMMARY

As envisioned in the Regional Representative Group's (RRG) regional proposal, Grid West will act as the central scheduling authority for the Grid West Managed Transmission System (GWMT). As the central scheduling authority, Grid West will implement a flow-based physical scheduling process. This process requires all Grid West Transmission Customers to possess the proper physical transmission rights prior to scheduling in the day ahead period. Physical rights may be in the form of existing transmission rights (ETRs) or Grid West-issued Injection Withdrawal Rights (IWRs). Grid West will manage these physical rights through three distinct processes:

- ***Physical Rights Inventorying***: Compilation of Transmission Owner rights obligations (TO obligations)
- ***ETR Certification***: Certification of Transmission Customer's existing transmission rights when requested by these customers
- ***IWR Translation Query***: Voluntary request for information regarding the translated value of a Transmission Customers' ETRs in terms of IWRs
- ***Bilateral Trade Registration***: Registration of IWR trades in the secondary market

Collectively, these processes are referred to as Rights Data Management (RDM).[1]

2.0 PURPOSE

The purpose of this white paper is to review the proposed Rights Data Management design, including Rights Inventorying, Rights Certification, Rights Translation Query, and Bilateral Trade Registration processes.

3.0 BACKGROUND

Currently, no single entity has a regional view of the Northwest transmission system prior to real-time.[2] The region's transmission capacity is managed

[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.

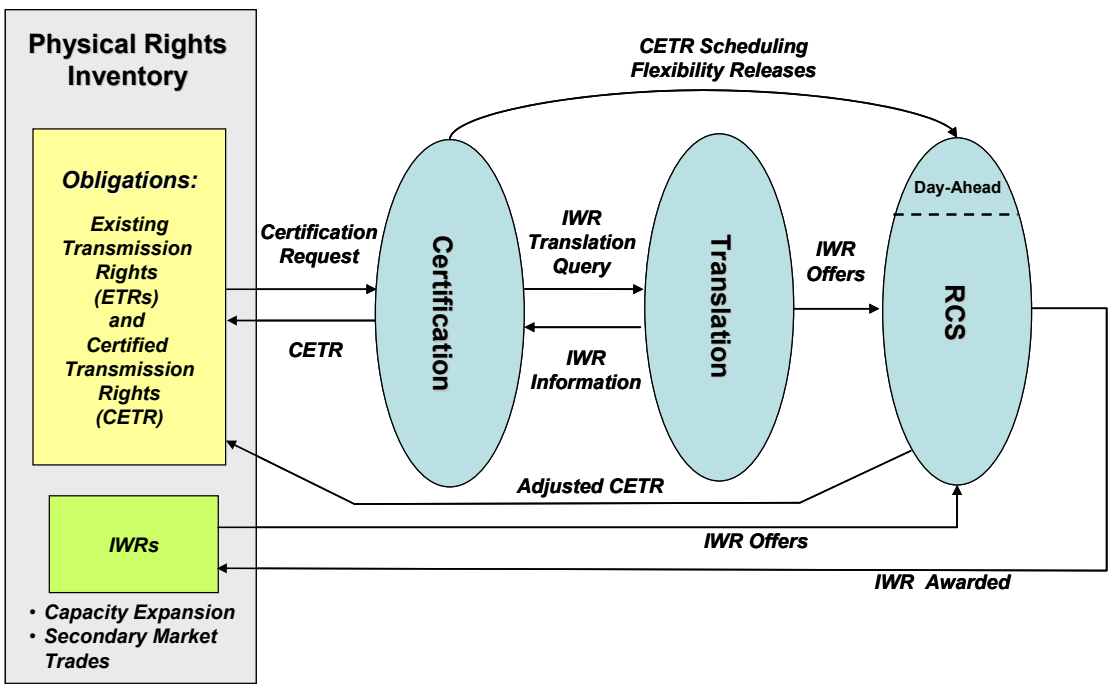
principally on a "contract path" basis by 17 individual control areas. Finally, the current contract path methodology does not match the physical operation of the transmission grid. In addition, each Transmission Operator determines its available transmission capacity based upon its own criteria.

As a part of its Basic Features, Grid West will centrally manage all scheduling activities within the GWMT. In this role, Grid West will not only have a regional view of the transmission system prior to real-time operation but will centrally mange transmission capacity in an independent manner. This new scheduling paradigm should have the capability to account for and honor all existing transmission rights, along with their full scheduling flexibilities, as well as all acquired IWRs.

4.0 RIGHTS DATA MANAGEMENT

As the central scheduling authority, Grid West will manage available flowgate capacity (AFC). This includes both pre-existing obligations derived from existing transmission contracts as well as incremental obligations due to the creation of new obligations (IWRs) through capacity expansion and the reconfiguration process.

Figure 4.1 – Rights Data Management Stages



[2] The Pacific Northwest Security Coordinator (PNSC) has real-time monitoring of the Northwest's transmission system, but lacking schedule information, it does not have look ahead capability.

4.1 Physical Rights Inventorying

The physical rights inventory will contain aggregated Transmission Owner obligations, certified existing transmission rights (CETRs) and Grid West-issued Injection Withdrawal Rights (IWRs). As opposed to performing a contract-by-contract review, Grid West will initially work directly with the Transmission Owners to determine and accurately inventory their aggregate obligations (TO obligations) related to all existing transmission rights. Hence, at the start there will be no CETRs in the physical rights inventory; however, this segment of data is expected to expand as more and more Transmission Customers certify their ETRs.

The physical rights inventory will be used to support three separate processes: the calculation of AFC, the validation of schedules, the validation of IWR and IRR offers and the operation of the Reconfiguration Service.[3]

4.2 ETR Certification

Transmission Customers with ETRs may want to schedule directly with Grid West and/or participate in the Day-Ahead Reconfiguration Service. To do so, these Transmission Customers must request to have their rights certified by Grid West. For each request, Grid West will work with the Transmission Customer and the impacted Transmission Owner to identify and certify the Transmission Customer's ETRs. ETR certification will produce a set of Certified Existing Transmission Rights (CETRs). Each CETR will include a set of scheduling points and its associated scheduling flexibility, if any.

Once certification has occurred, a Transmission Customer may offer scheduling flexibility associated with the certified right into the Day-Ahead RCS or use the certified right for energy scheduling purposes.

4.3 IWR Translation Query

After a Transmission Customer obtains a CETR, it may consider offering portions or all of its rights into the RCS auction. Since RCS auctions are based on standardized Injection-Withdrawal Rights (IWRs), the Transmission Customer must first determine the specific IWRs that could be released into the RCS based on its CETR (or a portion of it). To do so, the Transmission Customer will submit an IWR translation query. The query will include the source, sink and MW quantity of the portion of the CETR a Transmission Customer is planning to offer into RCS. The query can be for a specific time period (one hour, one day, one month, or one year) or for the entire duration

[3] See the Reconfiguration, Scheduling, and Bilateral Trading White Papers for additional details

of the CETR. The query can be to obtain a single IWR or set of IWRs. Using a flow-based model, Grid West will determine the IWR value of the translation query and send the information back to the Transmission Customer. In cases where Transmission Customers submit translation queries for only a portion of their CETR, Grid West will also provide information regarding the residual value of the remaining portion of their CETR.

Based on this information, the Transmission Customer has the option to offer the translated IWR value into the RCS or to retain their CETR in its original form. If the Transmission Customer decides to offer the translated IWR value into the RCS and its offer is fully or partially accepted, the accepted portion of their CETR will automatically be released into the RCS in the form of AFC with notice to the Transmission Customer. AFC released in this way is used to facilitate the issuance of IWRs requested by Transmission Customers through the RCS process. Any remaining portion of the CETR will be returned to the Transmission Customer and added back to the physical right inventory. This adjusted CETR can still be used for scheduling purposes.

The terms of the RCS auction awards are finite (one hour to one year). Thus, any awarded IWR and/or adjusted CETR will revert back to the original CETR at then end of the auction period.

4.4 Bilaterally Traded Rights Data Registration

Registration of bilaterally traded transmission rights, whether CETRs or IWRs, is another process of RDM. A Transmission Customer that makes a bilateral sale of transmission rights will initiate the registration process with Grid West. Grid West will confirm the transaction through interaction with the selling counterparty and, for ETRs, with the impacted TO. If confirmed, Grid West will register the transaction and update the rights data accordingly.

5.0 RIGHTS DATA FORMAT

The development of a common rights data format is one of the key steps in implementing Rights Data Management. The format should be flexible enough to account for all existing rights/obligations flexibilities and uniform enough to be efficiently stored and accessed. To help explain the concepts described in this paper, an example of the data types and formats are included in Appendix A.

6.0 ROLES AND RESPONSIBILITIES

Table 6.1 below presents the roles and responsibilities of Grid West and its participants related to RDM:

Table 6.1 – Rights Data Management Roles & Responsibilities

RDM Function	Grid West	Transmission Owners	Transmission Customer
Physical Rights Inventorying	▪ Receive, review and compile aggregated TO obligations data ▪ Standardize the format of the right	▪ Provide existing obligation information to Grid West	▪
ETR Certification	▪ Receive, certify and compile Transmission Customer's CETRs ▪ Standardize the format of the right	▪ Participate in the review and acceptance of CETR certification request by Transmission Customers	▪ Request ETR certification
IWR Translation Query	▪ Receive and review IWR translation query ▪ Provide IWR as well as residual CETR information	▪ Assist Grid West with IWR translation query review	▪ Submit IWR translation query
Bilateral Rights Data Registration	▪ Receive and review/confirm registration request ▪ Register bilaterally traded rights data	▪ Assist with registration review	▪ Submit registration request

7.0 MARKET BENCHMARKS

Existing RTOs and ISOs have converted their participants' ETRs into FTRs on a single occasion. After conversion to FTR, the ETRs cease to exist in their original form. One of the distinguishing features of Grid West is that Grid West, through RDM will ensure that holders of existing rights can hold onto and exercise those rights for their entire term. Table 7.1 provides a more detailed comparison of Grid West with PJM, ERCOT and MISO.

Table 7.1 – Rights Data Management Benchmarks

RDM Function	PJM	ERCOT	MISO	Grid West
Rights	▪ No explicit	▪ No explicit	▪ No explicit	▪ Review and

RDM Function	PJM	ERCOT	MISO	Grid West
Inventory	dealing with TOs on existing rights	dealing with TOs on existing rights	dealing with TOs on existing rights	compile TO existing rights data
ETR Certification	▪ N/A	▪ N/A	▪ N/A	▪ Performed once to allow ETR to be directly used by Transmission Customers
IWR Translation Query	▪ One time translation of ETRs to FTRs	▪ One time translation of ETRs to TCRs	▪ One time translation of ETRs to FTRs	▪ Temporary translation of ETRs to IWRs (on request)
Bilateral Trade Registration	▪ Voluntary registration and based only on request by participants and approval by RTO	▪ Voluntary registration and based only on request by participants and approval by RTO	▪ Voluntary registration and based only on request by participants and approval by RTO	▪ Voluntary registration and based only on request by participants and approval by Grid West

8.0 TECHNOLOGY SOLUTIONS

Most of the technology solutions needed for RDM are industry standard products. Table 8.1 provides a summary of such required technologies.

Table 8.1 - Technology solutions for RDM

RTO/ISO	Life of Issued Right
Physical Rights Inventory	Straightforward database forms for entering rights data in a standard structure.
ETR Certification	Straightforward database forms for entering ETR data in a standard structure.
IWR Translation Query	Straightforward database forms for entering IWR data.
Bilateral Rights Data Registration	Straightforward database forms for registering (entering) rights data in RDF structure.

9.0 COST DRIVERS

The cost driver for Rights Data Management is labor due to the manual processes involved. Costs could be reduced if:

- TOs perform existing obligation analysis under Grid West coordination
- Grid West increases the response time for ETR Certification and IWR Translation queries

10.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Inventory Granularity* – In order to accurately determine the existing obligations on the transmission system, how granular does the rights inventory need to be? Does the level of granularity need to change over time (e.g. after the 2 year transition)?

- *Netting for Certified ETRs* – Transmission Customers that choose to schedule directly with Grid West should certify their existing rights. As a result, Grid West will have to net their right and the flexibility associated with it out of their TO's aggregated obligations. The netting process needs further work from both process and technical viewpoints.

- *Netting for Translated IWRs* – As translated IWRs are offered into RCS and are potentially traded/awarded, they reduce the existing scheduling flexibility (ESF) of their underlying CETR. The calculation of the remaining ESF, for potential offer into DA-RCS, requires further work from both process and technical viewpoints.

- *Universal data format for ETRs* – Although Right Data Format presented in Appendix A is expected to cover most of all possible ETR contract forms, additional work is required to devise a universal format, if at all possible, that covers all possible ETR contract forms and at the same time can be electronically managed.

- *Direct Issuance of IWRs from Translation* – As described above, IWR Translation Query allows a Transmission Customer to release IWRs into RCS, but IWRs used for scheduling can only be obtained by purchases made in an RCS auction. In future work, thought needs to

be given to whether IWRs could be directly issued from a translation request and used for scheduling without going through the RCS auction.

APPENDIX A - SAMPLE RIGHTS DATA FORMAT:

Rights Data Format (RDF) development is a critical step in implementing the RDM. RDF should be flexible enough to account for all existing rights/obligations flexibilities and uniform enough to be efficiently stored and accessed in industry standard data storage technologies, e.g. relational databases. For this purpose we will use a format that contains the following information:

1. Right Identifiers: Uniquely identifies each right;
2. Right Owner(s): Identifies entity(ies) who own such right, if applicable;
3. Right Authorized Representative (RAR): Identifies the entity that can interface with Grid West regarding rights use and finances (this is expected to normally be the right owner);
4. Right Status/Origination: Identifies the status/history of the right including its origin within a right, if applicable;
5. Right Duration: Identifies calendar duration of the right (e.g., from now till 2050);
6. Right Timeline: Identifies duration of the right applicability (e.g., summer 2006 peak);
7. Right Injection Point(s): Identifies all scheduling point(s) that can be used as the right injection point(s);
8. Injection Right Value(s), or value ranges, at individual Right injection point(s): Identifies injections right MW value, range of values, at individual injection point(s);
9. Right Withdrawal Point(s): Identifies all scheduling point(s) that can be used as the right withdrawal point(s);
10. Withdrawal Right Value(s) [or value range(s)] at individual withdrawal points: Identifies injections right MW value, range of values, at individual injection point(s); and
11. Overall Right Constraint: Identifies a overall constraining factor on an existing right/obligation (ETR) such as the fact that total injection right where rights are presented in a range is limited.

The following table is intended to show this general format for an 800 MW flexible multipoint-to-multipoint right, held by Grid West participant "GWP2" through 2020, from scheduling points A, B and C to scheduling points U and V where

injection and withdrawal rights at every one of these scheduling points is also a variable as follows:

- Up to 400 MW injection right at scheduling point A
- Up to 300 MW injection right at scheduling point B
- Up to 300 MW injection right at scheduling point C
- Up to 400 MW withdrawal right at scheduling point U
- Up to 600 MW injection right at scheduling point V

The flexibility is shown in Table A.1.

Table A.1: Uniform Right Data Format

Right Attribute	RDF Value
Right Identifier	ETR2-MPtMP-2020
Right Ownership	GWP2
Right Authorized Rep	GWP2
Right Status/Origination	ETR2-GWP2
Right Duration	Now to 12/31/2020-HE24
Right Timeline	Regular
Right Injection point(s)	Buses A & B & C
Injection Right value(s)	$IR_A \leq 400MW$ & $IR_B \leq 300MW$ & $IR_C \leq 300MW$
Right Withdrawal point(s)	Buses U & V
Withdrawal Right value(s)	$WR_U \leq 400MW$ & $WR_V \leq 600MW$
Overall Right Constraint	$[IR_A + IR_B + IR_C = WR_U + WR_V] \leq 800$

The format presented in the above table is flexible enough to hold all information about the rights and can be readily implemented within a relational database framework.

SCHEDULING – MODULE 3a

Market Information System – Explains data and functional features of an information system that provides OASIS services, public information through a general website, and a private portal for scheduling, submission of bids and offers in markets, transmission of market results, settlement statements, etc.

Outage Coordination – Describes the proposed process Grid West will use to take a leading role in coordinating transmission outages. Generation outage information will be requested by Grid West to aid in reliability determinations, but coordination will not generally be performed and such data will not be made public.

Scheduling & Schedule Adjustments – Describes process and data needed by Grid West and its participants to schedule transactions including tagging, timing, etc. The paper describes the proposed process for adjusting schedules and checkout procedures required to ensure accurate interchange schedules and Net Scheduled Interchange between Balancing Authorities in or adjacent to the GWMT.

Transmission Losses – Confirms no change in the treatment of losses for pre-existing agreements and describes a proposed methodology to be used for calculation of loss responsibilities for schedules using IWRs.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

Grid West will be the single Transmission Service Provider (TSP) for new and converted transmission services. Transmission Owners (TOs) will continue to serve as the TSP for existing services with the TOs serving those OASIS needs.

These services require Transmission Customers to exchange information with Grid West. This information exchange requires several communication tools and applications, collectively referred to as the Grid West Market Information System (MIS).

Grid West will provide a single market information system for the Grid West Managed Transmission System (GWMT).[1]

This system will include the following components:

- A single Open Access Sametime Information System (OASIS) node
- A public Web site
- A private market portal

Grid West will post relevant information related to both regional and Consolidated Control Area (CCA) services.

2.0 PURPOSE

The purpose of this white paper is to describe the collection of systems making up the Market Information System and discuss the data available on the MIS. The MIS will be the primary interface between Grid West and its customers[2]. Grid West's need for scheduling, market operation and other internal information systems is not discussed in this paper.

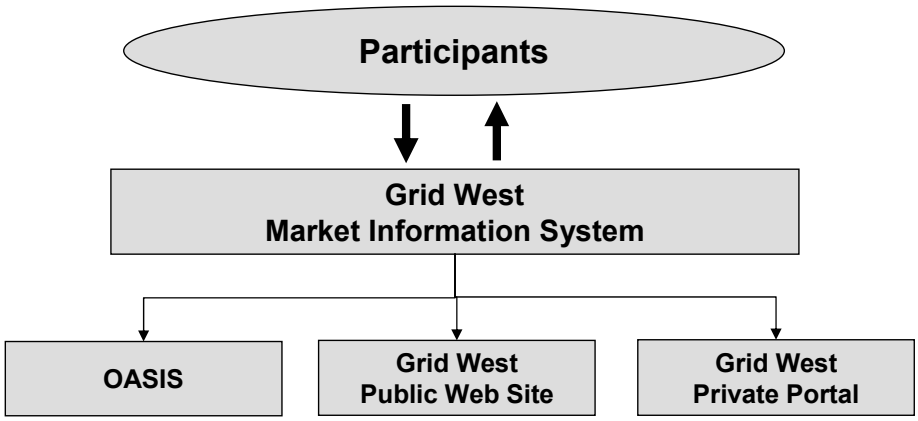
3.0 BACKGROUND

Grid West will perform several roles in the operations of Grid West's transmission system and the CCA. These roles require an efficient means for data to be communicated openly between Grid West and its transmission and non-transmission customers. The MIS depicted in Figure 3.0 is comprised of:

[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.
[2] The tag system will likely be independent of MIS, which remains to be determined.

- A single OASIS for the GMWT,
- A public Web site (www.gridwest.com) and
- A private market portal.

Figure 3.1 -- Overview of Grid West's Market Information System



Grid West will establish and maintain a single OASIS node for the entire GWMT system. The region currently has multiple sites so the consolidation into a single node will allow for more efficient communication of market and transmission-related information. A similar OASIS consolidation effort has been wesTTrans.net. Grid West should look to leverage existing solutions where possible in order to minimize cost. For example, some of the functions of the OASIS node may be provided by third-party service providers.

4.0 GRID WEST OASIS

For new and converted services, Grid West will provide a single OASIS node for transmission service providers who sign a transmission agreement with Grid West, replacing the need for transmission customers to go to multiple sites, as has been the case to date. In establishing the single OASIS node, Grid West will comply with the basic requirements and business practices for the OASIS network as defined in Federal Energy Regulatory Commission (FERC) Order No. 889, including the standards and formats for OASIS nodes, and any additional FERC Orders or Western Electricity Coordinating Council (WECC) business practices. This site will provide a common interface for transmission customers taking pre-existing service from their TSPs and transmission customers taking service directly from Grid West.

Grid West will independently calculate total flowgate capacity (TFC) and available flowgate capacity (AFC) for all the flowgates in the GWMT. Grid West's OASIS will maintain transmission information for Grid West transmission customers; provide CCA-related market information for the CCA service providers and users; and allow access to any of this information as appropriate to other authorized users of Grid West's OASIS site.

The public information posted on OASIS will be open to all transmission customers and to the public. Private information about transmission requests will be directed to the private portal where private information about specific transmission customers is protected and only available to the registered users that are authorized by the transmission customers' companies.

This paper describes the general functions of the Grid West OASIS perform, such as the posting of system information.

4.1 Transmission Service Requests

An eligible transmission customer can request transmission service using Grid West's MIS[3]. Responses will also be received via the MIS.

Grid West's planning department will process the long-term requests (requests longer than one year) using planning tools and other evaluation methods[4]. A system impact study will usually be needed and its study results will be sent to the requesting transmission customer via OASIS. A manual procedure will be used for this purpose.

Requests for Firm Transmission with durations less than one year will be processed as part of the Reconfiguration Service (RCS)[5]. Grid West has defined the following RCS products:

- Annual On/Off Peak
- Monthly On/Off Peak
- Balance of Month On/Off Peak
- Daily

[3] New transmission requests for service on the GWMT will come to Grid West. Requests for new rights will no longer be provided by the transmission owners. Requests to exercise features of pre-existing rights like redirects would go to the original TSP interface, and the functionality to enable that could be built into the OASIS if it is reasonable and done today.
[4] See also the white paper on Regional Planning & Capacity Expansion.
[5] See the Reconfiguration white paper for additional detail.

All requests will be accumulated and processed simultaneously by the RCS process. The RCS results will be available to requesting transmission customers via the MIS. This process will be automated.

The last RCS auction for a given operating day will be completed as a part of the Day-Ahead process. Requests submitted after the close of the daily scheduling process will be processed on a first-come first-served basis.[6] In evaluating these requests, Grid West will use a flow-based approach by which flows on all constrained or potentially constrained flowgates are computed by using the applicable Path Utilization Factors (PUFs) and the proposed schedule or schedule changes. Responses to these requests will be available to requesting transmission customers via the MIS. This process will be automated.

4.2 Transmission Information

4.2.1 Posting Service Products and Prices

Regional and market-related products and services offered by Grid West will be described on the MIS, along with the link to the applicable tariffs and business practices. The transmission-related services for the region include:

- Reconfiguration services (RCS)
- Long-term expansion services
- Loss management
- Registration for the secondary rights market
- Scheduling services
- Transmission-related ancillary services

The market-related services for the CCA include:

- Reserve services
- Real-time balancing services

4.2.2 Posting Transmission Capacity

Grid West will calculate and post available AFCs and PUFs. In addition, Grid West will post the methodologies for calculating the transmission capacity prior to the start of Grid West operation.

The frequency of posting and updating for various data elements on the MIS has not been determined. However, it will be consistent with OAISIS

[6] See white paper on Scheduling Adjustment.

requirements. It will be necessary for Grid West to update and post the AFCs before and after the various RCS auctions and before and after the day-ahead scheduling process at a minimum.

The timeframe for the AFCs has not been determined yet. Grid West will, however, match the timeframes of the posted AFC with the timeframes of the products used in the various RCS auctions.

4.2.3 Posting Transmission System Information

Grid West will post detailed information of all potentially constrained flowgates within the GWMT. Grid West will also post scheduling-related information such as curtailments, transmission outages, and the inventory of points of receipt and delivery, also referred to as injection points and withdrawal points.

Grid West will post day-ahead to seven-day ahead load projections in the GWMT and other host control areas, as well as the flowgate constraint projection information if available.

Grid West will post outage information that impacts the AFCs. The planned transmission facility outage schedule for the current month and the following three months will be posted[7]. The outage schedule for the planned generation facility will not be published.

Grid West will post information on loss factors for transmission customers to evaluate their loss obligations for the following seven days.

4.2.4 Posting List of Studies

When Grid West receives a long-term request, a system impact study may be conducted. The study on whether there are enough AFCs to accommodate the request will be available to the requesting customer. However, a list of all studies will be posted.

4.3 Posting Reserve Service Offerings and Prices

The types of reserve services that may be provided to the CCA will include the following:

- Regulating reserves

[7] See white paper on Outage coordination.

- Spinning reserves
- Non-spinning reserves

The auction prices will be posted after the close of the reserve auctions.[8]

Aggregated, non-confidential market summary data (e.g. summarized bid quantities and market clearing prices) for the reserve services will be posted after the close of the reserve markets.

4.4 Posting Real-time Balancing Service Offerings and Prices

Grid West will post real-time clearing prices for the CCA service area when they become available.

Grid West will post real-time or anticipated system conditions impacting the CCA real-time balancing services.

Aggregated, non-confidential market summary data (e.g. bid quantities, market clearing prices) for real-time balancing services will be posted when the information is processed and available.

5.0 TRADITIONAL OASIS SERVICES

Grid West's OASIS will also provide the traditional OASIS services using a common interface for each of the TSPs joining Grid West. Transmission customers will be able to use the Grid West OASIS to access service under the pre-existing arrangements from their existing TSP.

Examples include:

- Posting transmission for bilateral re-sales
- Re-assigning transmission rights
- Re-directing transmission points of delivery and receipt

These services will also be provided for transmission customers taking service from Grid West as applicable under FERC rules and WECC business practices.

[8] Additional information will be in the Reserve white paper.

6.0 GRID WEST PUBLIC WEB SITE

The Grid West public Web site (http://www.gridwest.com) will be used to publish public information on how to conduct business with Grid West. Examples include:

- Grid West Tariff
- Grid West Protocols
- Grid West Business Practices
- Grid West Bylaws
- Grid West Market Data

7.0 GRID WEST PRIVATE MARKET PORTAL

The Grid West private market portal will be used to accept and publish private information related to markets such as:

- Rights management and translation services
- Reconfiguration service (IWR auctions)
- Day-ahead scheduling and curtailments, as appropriate
- Schedule changes after day-ahead scheduling, including transmission redirects
- Real-time balancing data
- Reserve service
- Other market notifications
- Settlement data

Participants will require proper credentials to gain access to private market data.

The Grid West private market portal may assume some of the traditional OASIS functionality of the existing OASIS of the transmission owners who will become part of Grid West as described in Section 5. The interfaces and data flow are to be discussed with TSPs joining Grid West. However, it will be consistent with applicable orders (e.g., Order 638, 605, 889, etc.).

8.0 MARKET BENCHMARK

The design of Grid West's MIS will be similar to existing RTOs in terms of its functional capability. Robust markets, such as MISO and PJM, have developed programmatic interfaces to facilitate the automated exchange of information.

9.0 TECHNOLOGY SOLUTIONS

The major components of the MIS include[9]:

- OASIS
- Public Web site
- Private market portal
- Programmatic interface using XML that conforms to a published schema or set of schemas (to facilitate automated data exchange between Grid West and participants).

10.0 COST DRIVERS

Existing markets use a robust market portal with programmatic interfaces for some of the functions described above. The primary cost drivers for Grid West's MIS implementation relate to the technology costs and some operational costs.

- Number of market interfaces
- Programmatic features
- Number of market products
- Report posting frequency
- AFC and RCS posting frequency

One cost consideration for Grid West is the possibility of outsourcing a portion of the MIS (e.g. OASIS) to a third party.

11.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Tag and scheduling system* - Besides the Market Information System, Grid West will need a system for processing tags and interchange, which should be further considered.

[9] The identified requirements may overlap with these identified in the Interchange and other white papers.

1.0 EXECUTIVE SUMMARY

As envisioned in the Regional Representative Group's (RRG) regional proposal, Grid West will be the central scheduling entity for the Grid West Managed Transmission (GWMT) System. As such, Grid West will administer the day-ahead scheduling process. This paper describes the proposed scheduling process for Grid West.[1]

Highlights of this paper include:

- Pre-existing rights holders will continue to submit schedules to the Transmission Owners (TOs) who issued the rights
- TOs will combine their customers' schedules and submit balanced schedules to Grid West
- Injection/Withdrawal Rights (IWR) Transmission Customers will submit their balanced schedules directly to Grid West
- Grid West will validate submitted schedules against customers' rights
- If necessary, Grid West will use pro rata curtailments to resolve infeasibility
- Post day-ahead scheduling changes will be evaluated on a "first-come, first-served" basis
- All schedule submissions must be balanced
- Schedules crossing control area boundaries will require e-tags
- Grid West will administer schedule checkout

2.0 PURPOSE

The purpose of this white paper is to discuss the following processes of the proposed scheduling design:

- Day-ahead scheduling
- Day-ahead schedule adjustment
- Post day-ahead schedule changes
- Interchange scheduling
- Checkout

[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

Currently, no single entity has a regional view on a day-ahead basis of the planned use of the Pacific Northwest transmission system[2]. The region's transmission capacity is managed on a "contract path" basis by individual control areas. Schedules under the contract path methodology do not match the actual physical power flows on the transmission grid. In addition, each transmission provider determines its Available Transfer Capability (ATC) based upon its own criteria. Each transmission provider maintains either its own Open Access Same-Time Information System (OASIS) or its own environment on a common OASIS and manages its transmission reservations and energy schedules.

From the perspective of Transmission Customers, transmission service requests are generally processed through the use of a transmission provider's OASIS. The service durations can be divided into long-term and short-term (hourly, daily, weekly and monthly). The short-term service can also have different priorities as firm and non-firm.

Once the service is granted, most Transmission Customers submit their schedules to their transmission providers. The transmission providers typically require that all interchange schedules have associated OASIS reservations supporting these schedules. However, a transmission customer often can designate a scheduling agent for all aspects of its transmission scheduling. Load-serving Entities (LSE) may need to create e-tags for schedules impacting net scheduled interchange, although some transmission providers request the provision of e-tags for other types of flows. Lastly, each transmission provider decides on its own curtailment or adjustment procedure when transfer capability is insufficient.

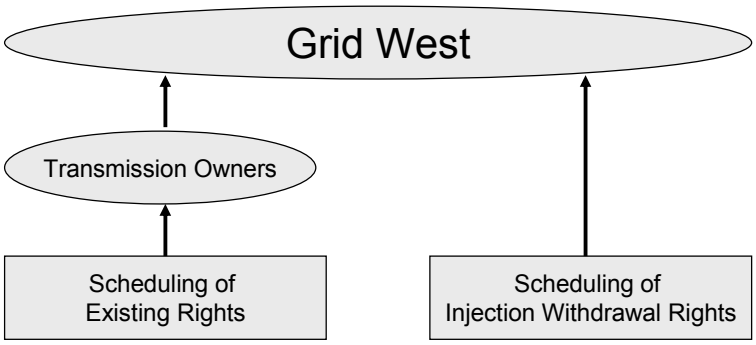
Grid West is expected to become the Transmission Service Provider for the GWMT system, responsible for administering the scheduling of the transmission systems of TOs signing a Transmission Agreement (TA). As the Transmission Service Provider for the GWMT, Grid West will not only have a regional view of the transmission system, but also centrally manage transmission capacity as an independent party. This new scheduling arrangement will honor pre-existing transmission rights, as will be discussed in this paper.

[2] The Pacific Northwest Security Coordinator receives sufficient operational information to provide a comprehensive view of the entire Northwest Power Pool in real-time.

4.0 DAY-AHEAD SCHEDULING

During the day-ahead scheduling process, each IWR holder can submit its proposed and balanced schedules to Grid West. Transmission customers with pre-existing transmission rights will submit schedules to the TO[3] who issued the rights. The TOs will verify that submitted schedules are consistent with the terms of the pre-existing rights, combine these schedules with the TO's affiliated merchant's (or Load-serving Entity's) non-contract based schedules (e.g., for native load service), and submit them to Grid West. Transmission customers with pre-existing transmission agreements will continue to provide loss obligations to their TOs using their contractual loss factors. Loss obligations for schedules using IWRs will be computed using the applicable loss factor[4] and losses schedules to meet these obligations will be submitted to Grid West. The proposed process of schedule submission to Grid West is shown in Figure 4.1. The proposed schedules will be submitted through the Grid West's Market Information System (MIS).

Figure 4.1 -- Day-ahead Schedule Submission



A summary of Grid West's day-ahead scheduling process and activities is presented below in Table 4.1 and in Figure 4.2. The timelines shown are illustrative; the actual scheduling timeline will be established in Grid West's protocols which will be developed prior to commencement of actual operations.

Table 4.1 -- Day-Ahead Scheduling Process and Activities

Time Period	Grid West	Transmission Customer	Transmission Owner
By 08:00		• Bilateral trading	

[3] It is expected that a process will be in place for transmission customers with pre-existing rights to translate their rights to IWRs and schedule directly with Grid West.
[4] See the white paper on losses for details.

Time Period	Grid West	Transmission Customer	Transmission Owner
		• Submit bids and offers to DA-RCS	
By 09:00	• Perform DA-RCS		
By 10:00	• Update existing rights inventory • Update AFC based on the DA-RCS results		
By 11:00		• Existing Rights Holders submit schedules to TOs	
By 12:00		• IWR holders submit schedules to Grid West	• Submit aggregated schedules to Grid West
By 13:30	• Validate schedules against rights inventory • If feasible, Grid West will accept the schedules and publish final schedule • If infeasible, Grid West will perform curtailment procedures		
By 14:00	• Post curtailment notices and publish final schedule		
By 15:00		• Obtain final schedule • Create E-tags	• Obtain final schedule
By 16:30	• Tag Approval		
By 17:00	• Day-ahead checkout		
On-going from 14:00 to 20 minutes before the start of operating hours	• Evaluate, accept or deny schedules ("first-come, first-served") using PUF and AFC	• Submit schedule change or new request	• Submit schedule change or new request[5]

[5] For schedule change of pre-existing rights, TO will be responsible for submitting the change requests to Grid West.

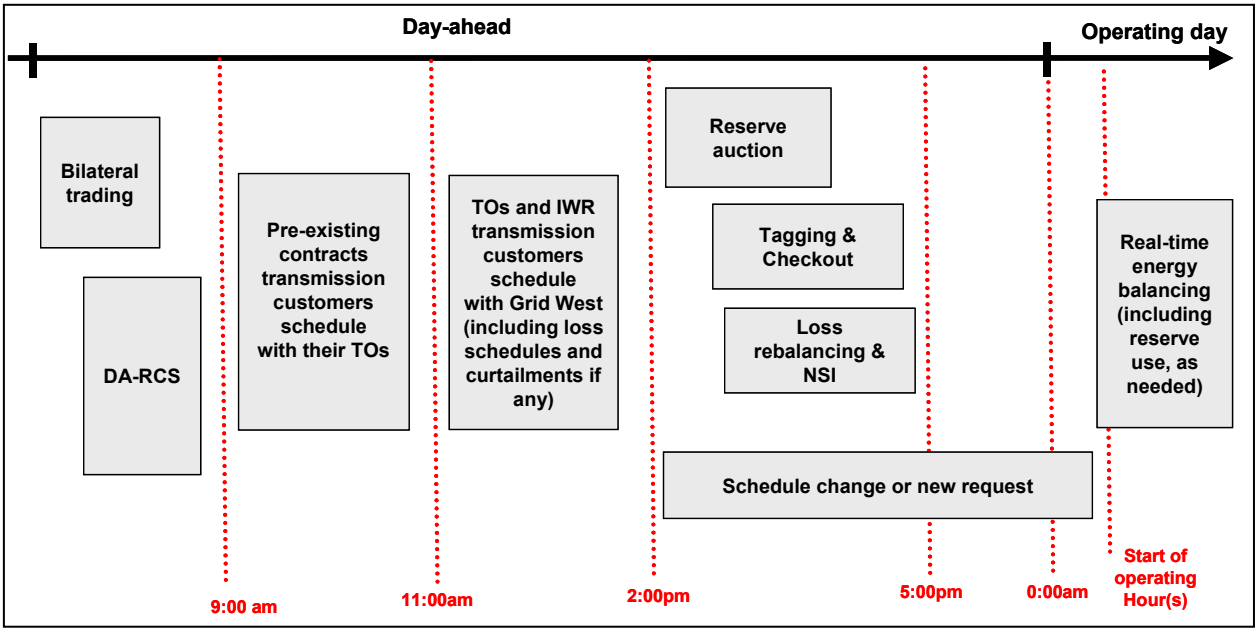


Figure 4.2 -- A Summary of Grid West's Day-ahead Scheduling Processes

5.0 DAY-AHEAD SCHEDULE ADJUSTMENT

After combining all proposed day-ahead schedules submitted by Transmission Customers and Transmission Owners, Grid West will analyze the transmission usage and identify potential transmission problems. Grid West will manage congestion using a flow-based approach, relying on the ex ante nature of physical rights. This approach is intended to deal with congestion by preventing energy schedules that would cause congestion, i.e., loading in excess of line (or path) ratings. If all transmission rights are properly defined, the GWMT should have sufficient transmission capacity to support all rights holders' transactions. However, because there will be inevitable differences between expected conditions when rights are issued and actual conditions, it is possible that the combined schedules may be physically infeasible within system reliability limits even though all schedules are covered by physical transmission rights. This may be due to forced outages, changes in generation conditions or an unexpected loss of diversity for over-subscribed paths. In practice, some limited over-subscriptions are reasonable to further increase the utilization of the transmission systems because not all contract rights will be used simultaneously.

If, for any of these reasons, the proposed schedules are physically infeasible to accommodate all schedule requests simultaneously, a backstop process for schedule adjustment and curtailment will be used to satisfy the system reliability limits.

When transmission problems are present as described above, Grid West will reduce schedules using a methodology which minimizes the curtailment amount and provides a means for equitable curtailments.

The adjustment procedure will curtail the proposed schedules proportional to their contributions to congestion or infeasibilities, or proportional to their rights on the constrained facilities. Grid West will not distinguish schedules based on IWR or pre-existing rights for curtailments, i.e., all schedules are on equal footing for curtailment purposes[6].

The schedule curtailments are not the same as load shedding. Curtailed schedules mean reduction of both injection and withdrawal quantities. However, transmission customers can still serve loads through other means, such as scheduling different resources in the post day-ahead period, just as they do today. If transmission customers fail to provide resources to match their load, they may face imbalance charges.

Grid West will develop and use pro rata curtailment with a flowgate-specific procedure. This approach is based on the current curtailment procedures in many of the Northwestern utilities. The main procedure is a two-step process:

1. Identify the contributing schedules causing the infeasibilities (schedules with negligible impacts to the constrained flowgates can be ignored)
2. Perform pro rata reduction of the schedules to resolve infeasibilities

Specific procedures are to be developed based on off-line analyses and study for specific flowgates by taking the special circumstances around the flowgates[7]. After identifying the contributing schedules, the pro-rata allocation of the desired reduction amount can be based on either the scheduled amount or the contracted entitlement amount. Currently, the practice of pro-rata reduction varies with different utilities. For example, in BPA's practice, the allocation of the reduction uses the actually scheduled MW quantity on the constrained path. In

[6] Curtailment of dynamic schedules and pseudo ties will be considered along with the typical transmission schedules. Details of this consideration will be investigated in a later time.
[7] For example, BPA has developed specific curtailment procedures (curtailment calculators) for specific flowgates at Paul – Allston, North of Hanford, West of McNary, and others.

Avista's practice, however, the allocation of the reduction is based on the entitlement to use a path.[8]

A numerical example of the pro-rata allocation is given in Appendix A showing the process and steps of curtailment calculation in a looped network.

6.0 POST DAY-AHEAD SCHEDULING

The Post Day-ahead Scheduling period covers the period from the close of day-ahead scheduling to a time close to the ramping period of the operating hour. During this time period, Grid West will accept both schedule adjustments and new requests for transmission service. These requests will be submitted through the Grid West's Market Information System.

Each request will be evaluated on a "first-come, first-served" basis. Grid West will perform the following actions for each request:

- ***Rights Validation:*** Schedule change requests should be consistent with rights.
- ***Impact Analysis:*** All requests will be analyzed based upon Available Flowgate Capacity (AFC) and Path Utilization Factors (PUF).

In the post day-ahead adjustment period, Grid West will assign lower priority to unused capacity granted after the close of the day-ahead scheduling process. In case of subsequent curtailments, post –day-ahead schedules will be curtailed first before the curtailments of the approved day-ahead schedules.

Grid West will use a flow-based approach for evaluating requests for transmission service under the Regional Tariff. Under a flow-based approach, flows on constrained facilities (flowgates) are computed by using the applicable PUFs and the proposed schedule. Grid West will ignore those flowgates on which the impact of the requests is minimal based upon a threshold it will establish for measuring this impact. When a new request results in overloading a path, e.g., load exceeds the AFC on any of the constrained and potentially constrained flowgates excluding constraints which are deemed minimal, say below 1 MW, the transmission service schedule change or new request will not be approved.

[8] A more comprehensive discussion of this issue is given in "Possible Pro Ration Methods for Mid-Hour Curtailments", John Anasis and Laura Oliver, BPA Transmission Scheduling, TBL Customer Forum, January 21, 2003, //www.bpa.gov.

Under OATT, Transmission Customers can request to modify Point of Delivery (POD) and Point of Receipt (POR) without being obligated to pay any additional costs. This redirect option is granted when there is adequate transmission capability to accommodate the request. Grid West will treat redirects as a change request to the original schedule; these requests will also be subject to availability of AFCs on the applicable paths. The tracking of redirects and notice to the original transmission provider need to be further considered in system development. The treatment of redirects will comply with the North American Energy Standards (NAESB) Wholesale Electric Quadrant (WEQ) redirect standards.

7.0 INTERCHANGE SCHEDULING

The GWMT may be composed of several balancing authorities, including the consolidated control area (CCA) and any non-CCA balancing authorities. Grid West will classify schedules as either: 1) interchange, or 2) internal as described in Table 7.1. An interchange schedule is a schedule between balancing authorities. An internal schedule is a schedule within a single balancing authority.

Table 7.1 -- Grid West Schedule Classification Example

Schedule Instance		Schedule Classification
POD (or POR)	**POR (or POD)**	
CCA	CCA	Internal schedule
Non-CCA	The same non-CCA	Internal schedule
CCA	Non-CCA	Interchange schedule
CCA	Non-GWMT	Interchange schedule
Non-GWMT	Non-GWMT[9]	Interchange schedule
Non-CCA	A different Non-CCA	Interchange schedule
Non-CCA	Non-GWMT	Interchange schedule

In compliance with North American Electric Reliability Council (NERC) Version 0 Reliability Standards, Grid West will require tags to be submitted for all interchange schedules between balancing authorities, which will be generated by the Purchasing/Selling Entity's (PSE) LSE. Grid West can also create the

[9] i.e., "through and out" wheeling transactions.

necessary tags on behalf of the Transmission Customers[10]. Grid West will comply with NERC's tag timing requirements. Tags may be used to compute net schedule interchange for the balancing areas, which is needed for Automatic Generation Control (AGC) operations. Grid West can also compute net schedule interchange (NSI) for Balance Authorities not in the CCA if such an arrangement is made between Grid West and these Balance Authorities. Transactions within the CCA balancing authority or within the same non-CCA balancing authority will not need to be tagged.

Western Electricity Coordinating Council (WECC) business practice requires tags to include the transmission segments segregated along control area boundaries even though Grid West will be the Transmission Service Provider for the entire region. Because of the regional and flow-based nature of day-ahead schedules, interchange schedules may cross several control area boundaries. Within Grid West, the schedules across balancing area boundaries will be evaluated in terms of the flow-based effects of the combined Grid West schedules rather than contract paths.

Grid West will serve as the transmission provider to the GWMT and balancing authority for the CCA, approving or denying tags as appropriate for these functions. Grid West's scheduling system will validate and automatically approve or deny NERC tags matching the final day-ahead schedules. This can be accomplished by comparing the common reference numbers on the tag against the scheduling database. The loss reallocation tag will also be generated and approved in this process. This automation requirement will improve the efficiency and tag processing.

8.0 CHECKOUT PROCESS

To ensure accurate interchange schedules and net scheduled interchange with neighboring interchange authorities, Grid West will conduct checkout for the entire GWMT. In accordance with NERC Version 0 Reliability Standards on interchange scheduling, every balancing authority has the responsibility to verify their net interchange with their own neighboring balancing authorities, which can be done after Grid West finalizes all scheduled interchange.

In a typical checkout process, two adjacent balancing authorities perform the checkout based on approved E-tags between them. The balancing authorities work to resolve any discrepancies arising in the checkout process. The end result

[10] Agreements between Grid West and transmission customers are needed.

of the checkout process is that all interchange schedules between adjacent balancing authorities are verified and consistent.

There are three separate checkout processes for a balancing authority:

- Day-ahead checkout
- Pre-real-time checkout
- After-the-fact checkout

Grid West will be responsible for the day-ahead, pre-real-time (before-the-fact), and after-the-fact checkout processes for the CCA.

The WECC is in the process of implementing an automated tool for the checkout process. This tool is called the Western Interchange Tool (WIT), which will provide a mechanism for verifying and crosschecking scheduled net interchange values based on tags. WIT will facilitate adjacent net interchange checkout and provide a single source of information on confirmed interchange. When this tool is available, Grid West will leverage WIT to reduce costs and improve the efficiency of the checkout process.

9.0 ROLES AND RESPONSIBILITIES

9.1 Grid West

Grid West will:

- Calculate and publish updated AFCs after the close of the RCS market
- Update the latest inventory of IWR rights after the close of the RCS market
- Receive and validate submitted day-ahead schedules
- Perform analysis of submitted day-ahead schedules
- Perform day-ahead schedule adjustments, if necessary
- Approve interchange schedules and tags for all transactions in the GWMT
- Communicate the final resource schedules and/or NSIs to the balancing authorities within GWMT and its Transmission Customers
- Receive and validate the submitted scheduling change requests after day-ahead
- Respond to scheduling change requests
- Approve the request if the flowgate sufficient AFC is available
- Manage loss provision

- Manage the day-ahead and near real-time checkout processes for the CCA
- Manage the after-the-fact checkout processes on behalf of the CCA
- Perform balancing authority responsibilities for the CCA

9.2 IWR Transmission Customers

IWR Transmission Customers will:

- Submit proposed day-ahead transmission and loss schedules to Grid West
- Resolve any validation issues after receiving notifications from Grid West
- Create tags for interchange schedules as appropriate
- Submit schedule requests consistent with the specification by Grid West
- Request tag changes or create new tags, as necessary, from the approved request

9.3 Transmission Customers with Pre-existing Rights

Pre-existing rights Transmission Customers will:

- Submit balanced day-ahead schedules within their rights to the appropriate TO
- Schedule the loss obligations to their TOs per pre-existing agreements
- Ensure creation of tags for their interchange transactions where they are the LSE
- Submit proposed day-ahead transmission and loss schedules to their TOs
- Submit proposed post day-ahead change or new requests to their TOs as appropriate

9.4 Transmission Owners

Transmission Owners will:

- Validate, combine and submit schedules of Transmission Customers with pre-existing rights, including those of non-contract customers, such as affiliated merchants or LSEs serving native load

9.5 Balancing Authority Operators

Balancing authority operators will:

- Manage the after-the-fact checkout processes

10.0 MARKET BENCHMARKS

For day-ahead scheduling, Grid West is unique compared to most RTO/ISOs because physical rights are required and only small and infrequent adjustments to submitted balanced schedules are expected. A curtailment process is used as a backstop mechanism to manage congestion when the combined schedules (all covered by valid transmission rights) prove to be infeasible due to unforeseen system conditions. Existing RTOs use a day-ahead congestion management process to derive final schedules from market bids and offers. In contrast, Grid West will rely upon a schedule adjustment process in the post day-ahead process which is similar to current practices of the Transmission Owners. Grid West's interchange scheduling and checkout processes are similar to the interchange scheduling practice in many existing RTOs. The main differences for interchange scheduling lie in the specific timing requirements and in the procedures related to Grid West's unique market structure, which involves multiple Balancing Authorities.

Table 10.1 includes a comparison with existing RTOs in the schedule adjustment in the day-ahead and the post day-ahead periods, and Table 10.2 includes a comparison with existing RTOs in interchange and checkout processes.

Table 10.1 -- A Short Comparison of Scheduling Adjustment Process

Timing	Grid West	ERCOT	PJM and MISO
Day-ahead Scheduling Adjustment	• Use physical rights and pro rata adjustment if necessary	• Zonal based congestion management using zonal Shift Factor • Adjust balancing energy to resolve congestion and uplift costs.	• LMP based on central energy market in the new MISO design
Post Day-ahead Scheduling Adjustment	• Flow based and "first-come first-served"	• Similar to OATT procedure	• PJM allows only interchange schedules, others go to real-time market • MISO uses real-time market and allows changes for physical bilateral

			transactions

Table 10.2 -- Interchange Scheduling and Checkout Benchmark

Process	Grid West	Other RTOs/ISO
E-tag	Standard	Standard
Schedule classification	Internal and interchange	PJM: External MISO: Physical bilateral and financial
Loss	Not used	Many uses a marginal or scaled marginal loss price component embedded in the Location Marginal Prices (LMP)
Special features	CCA and non-CCA bilateral transactions	Pool-like and financial transactions
Day-ahead checkout	Standard (except no checkout needed between balancing authorities within GWMT)	Standard
Near real-time checkout	Standard (except no checkout needed between balancing authorities within GWMT)	Standard
After-fact checkout	Standard	Standard

11.0 TECHNOLOGY SOLUTIONS

The major components of the scheduling system include[11]:

- Market Information System, including OASIS
- Scheduling system
- Tag applications and interfaces
- AFC update and calculation
- Day-ahead adjustment application
- Request evaluation application in post day-ahead

[11] The identified requirements may overlap with these identified in other white papers.

12.0 COST DRIVERS

The primary cost drivers for implementation relate to the required software systems and personnel requirements. The primary cost drivers are:

- Number of day-ahead and post day-ahead schedules
- Frequency of schedule infeasibilities and curtailments
- Number of interchange schedules
- Number of tagging errors
- Number of schedules for checkout
- Number of checkout discrepancies to be resolved
- Extent of information to be verified after-the-fact

The costs may be reduced if Grid West:

- Streamlines the scheduling, interchange scheduling and tag creation processes with automated software applications
- Leverages existing systems and software for its needs in scheduling and tag management

13.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- Economic approach for avoiding curtailments.

- Balanced schedule requirement for curtailed portions of schedules.

- Loop flow and outage-related curtailments in real-time operation. Grid West should also consider the impact of loop flow curtailment on the AFC and scheduling changes in post day-ahead period.

- *DC lines scheduling* - The coordination of DC scheduling and its impact on Grid West's AC system need to be considered.

- *Phase shifter scheduling* - Grid West should develop procedures for determining phase shifter setting in order to maximize market value and transmission utilization.

- *Dynamic schedule tagging requirements* - Same as reserve tags in reserve paper.

- *Tagging before day-ahead* - Tags can be created before day-ahead for some transmission users. Grid West's approval is conditioned on the final

schedules in day-ahead. A procedure of approving pre-day-ahead tags may be needed.

Appendix A: Schedule Adjustment Examples

This section provides a comprehensive example illustrating the application of adjustment procedures.

Base Case Situation

The example case has three buses with equal 120 MW total flow capacity (TFC) on each link, as shown In Figure A1.

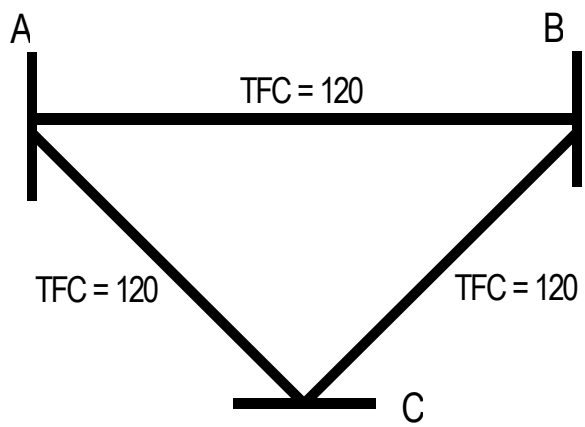


Figure A.1: Example System and Base Situation

Assume in the day-ahead scheduling process, there are six submitted schedules as shown in Table A.1. The predominant flows are from A to C and from A to B. The last three schedules (Schedules 4 to 6) are small and generate some counter flows on the three paths.

Table A.1: Proposed Schedule Data for the Base Situation

Schedules	POR	POD	MW
1	A	C	150
2	A	B	90
3	B	C	60
4	C	B	15
5	C	A	6
6	B	A	9

The line flows resulting from the applications of these schedules are listed in Table A.2. The flows from A to B and B to C are within their operational limits. However, the flow on the flowgate between A and C exceeds its limit by 18 MW.

Grid West must decide how to adjust the six schedules in order to achieve the 18 MW reduction on A to C.

Table A.2: Line flows of the Base Situation

From	TO	MW
A	B	87
B	C	51
A	C	138

Adjustment Solution using Pro Rata Cut

Given the infeasibility, Grid West decides how to adjust the six proposed schedules in order to achieve the 18 MW reductions on A to C.

This sub-section illustrates the pro rata reduction method. The results of reduction calculation process and resulting flows are listed In Tables A3 and A4.

In order to achieve an expected reduction of 18 MW from A to C, several steps are needed:

Step 1. Grid West first computes the use of A to C, as shown in third column of Table A3, by evaluating all submitted schedules, as shown in the second column of Table A3.

Step 2. Grid West then identifies schedules contributing to the flow from A to C. In this case, the schedules 1- 3 are contributing schedules as flagged in the fourth column of Table A3.

Step 3. The pro rata allocation of required 18 MW reductions from A to C is performed based on the use of A-C. The results are shown in the fifth column of Table A3.

Step 4. The required reduction from A to C needs to be reflected to the original submitted schedules. The results of schedule reductions are shown in the sixth column of Table A3.

The Schedule Reduction * Applicable PUF = Allocated Flow-based Reduction

Step 5. The final schedules are the differences of the proposed schedules and the schedule cut, as shown in the seventh column of Table A3. Note the total cut of the schedule is 36MW.

Table A.3 - Adjusted Schedule Data Using Pro Rata Cut

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
Schedule	Submitted	Use of A	Contributing	Allocated	Required	Final

	Schedule	to C	Schedules	Pro rata Cut from A to C	Reduction	Schedule
1	150	100	Y	12	18	132
2	90	30	Y	3.6	10.8	79.2
3	60	20	Y	2.4	7.2	52.8
4	15	-5	N	0	0	15
5	6	-4	N	0	0	6
6	9	-3	N	0	0	9

Table A.4 -- Line flows after Pro Rata Cut

From	TO	MW
A	B	76.2
B	C	43.8
A	C	120

1.0 EXECUTIVE SUMMARY

The Northwest Power Pool (NWPP) maintains the outage coordination process for the region. Currently, BPA coordinates this process. As a part of Grid West Basic Features, Grid West will coordinate the process. For Transmission Owners who do not participate in Grid West, the existing outage coordination process is still applicable.

Transmission Owners who participate in Grid West will submit planned transmission outage requests to Grid West, which will manage the outage notification process under the procedures developed in conjunction with NWPP. For transmission outages, Grid West will review the outage requests, evaluate the schedules against reliability criteria and known generation outages, and approve the requests (if such an approval authority is vested in Grid West by the Transmission Agreement) or propose changes. Grid West will publish the transmission outage plan on OASIS. Grid West will exchange transmission outage information with other control areas for regional coordination.

Grid West will continue to work with regional stakeholders to improve the outage coordination process in order to minimize the negative impacts of outages on the stakeholders.[1]

Highlights of this paper include:

- Outages impact reliability – Grid West needs to be notified
- Proposed coordination methodology is based on the existing NWPP process
- Set of notification, comment, review and approval processes are needed
- Generation and transmission outages are treated differently
- Both generation and transmission outages are submitted by facility owners
- Grid West will propose alternatives if conflicts exist
- Grid West authority will be defined within Transmission Agreements
- Outage coordination is a regional service

2.0 PURPOSE

The purpose of this white paper is to review the proposed generation and transmission outage coordination design. This white paper discusses Grid

[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.

West's generation and transmission outage coordination processes for managing regional scheduling operation. Specifically, the paper describes the notification of generation and transmission outages, and the review processes by Grid West.

3.0 BACKGROUND

Regional transmission outage coordination and information sharing in the Northwest area is accomplished through the Northwest Power Pool (NWPP), a voluntary and member-based organization. The NWPP currently coordinates scheduled outages. The timeframe of the outage coordination covers the subsequent 120 days (Grid West will also collect outage information beyond 120 days if available and share it with stakeholders if possible[2]). The timeline and processes among Transmission Owners (TOs) and NWPP are highlighted in Table 3.1 below (or go to www.nwpp.org/pdf/OM-H2004May.pdf to see Section H "Coordination of Scheduled Outages"). In addition, the NWPP sponsors the NWPP Long Range Planning and Outage Coordination meetings.

Table 3.1 -- Current Timeline for Transmission Outage Coordination

Timeline (approximate)	Coordination Process
45 days prior to the outage month	Deadline for submitting significant transmission outages.
40 days prior to the outage month	List of significant transmission outages with capacity estimates posted on OASIS for customer comment.
Varies	Customer comment period closes.
Varies	Outage Coordination group meets to develop draft outage plan.
Varies	Draft transmission outage plan: approved transmission outage plan with capacity estimates posted on OASIS for customer comment.
30 days prior to the outage month	Customer comment period on approved transmission outage plan closes.
15 days prior to the outage month	Final transmission outage plan: plan with capacity estimates posted on OASIS.

Grid West will continue to participate in the regional coordination and information sharing efforts through the NWPP. For Transmission Owners who did not sign Transmission Agreements in Grid West, the current transmission outage coordination process as defined by the NWPP is still applicable. Transmission Owners who participate in Grid West will submit their planned outage requests to Grid West, which will be responsible for managing the outage notification process of NWPP. In addition, the Grid West will assume the responsibility for hosting the NWPP Long Range Planning and Outage Coordination meetings.

[2] Mechanism of the information sharing will be addressed in next design layer.

In its role as a regional service provider, Grid West will ultimately be responsible for maintaining reliable and coordinated system operation for the Grid West Managed Transmission (GWMT) System, which is affected also by outages outside GWMT. Therefore, Grid West will rely on information on planned and/or forced outages of key transmission and generation facilities provided in the outage-coordination process. In addition, outage information should also be exchanged with other control areas because the impacts of planned outages will not be restricted to the local control area within an interconnected electric power system[3].

4.0 GRID WEST'S AUTHORITY

Grid West's authority to approve or deny a planned outage of transmission facilities will be established contractually between Grid West and the Transmission Owners (e.g., Transmission Agreement (TA)).

Grid West will not have the authority to approve or deny generation outages.

5.0 TRANSMISSION OUTAGES

5.1 Notifications of Transmission Outages

Grid West will make available an electronic outage notification application to be used by Transmission Owners to submit or change transmission outage schedules.

Grid West will publish a listing of the transmission facilities in the Grid West transmission system subject to the notification requirements. Grid West will obtain from transmission facility owners their planned outage schedules in compliance with the NWPP Coordinated Outage System (or its successor) and procedures.

WECC has been charged to implement two systems for outage information sharing (Grid Alert System and WECCNet messaging system). Grid West will take advantage of these systems and follow the protocols set forth by WECC and NWPP notification requirements.

5.2 Data Needed for Transmission Outages

A transmission facility outage request should include the following information:

[3] The extent of information exchanged is to be determined.

- Transmission facility name and Grid West reference code;
- Nature of the transmission outage and maintenance to be performed;
- Amount of unavailable MW capacity[4];
- Start date, end date and time of the outage;
- Flexibility data (e.g. alternative periods of outage, time required to terminate the outage and restore the transmission facility to normal capacity);
- Known constraints regarding the outage (e.g., snow pack);
- Contact information; and
- Interdependencies or associations with other work or outages.

5.3 Public Comments on Transmission Outages

Transmission Customers will have opportunity to comment on the proposed transmission outage requests as well as the initial outage plans. The plans will be available through Grid West's Market Information System and/or NWPP's Coordinated Outage System. Grid West will consider these comments in the review process and will respond to these comments appropriately.

5.4 Review of Transmission Outages

Grid West will review transmission outage requests by considering the following factors:

- WECC critical maintenance work;
- Forecasted peak transmission demand conditions;
- Forecasted peak load conditions;
- Other known generation and transmission facility outages, both inside and outside Grid West;
- Impacts on Grid West's ability to honor the awarded Injection/Withdrawal Rights (IWR) and any flexibility of the existing transmission agreements;
- Violation of pre- and post-contingent rating of transmission facilities;
- Market prices of power;
- Potential load curtailments;
- Outage plans of adjacent control areas; and
- Comments and requests of stakeholders.

Grid West will use various network software applications to analyze transmission outages to establish operational transfer capabilities; determine

[4] Grid West will also independently verify and assess the unavailable MW Capacity,

their effects on transmission system reliability; determine if any one or a combination of proposed outages will violate reliability criteria; and develop mitigating actions as applicable. The evaluation objective will be to maximize the market value of power delivered by the transmission system subject to the applicable reliability constraints and criteria. Analysis tools include power flow, contingency analysis, stability analysis, market analyses and other study tools. If a conflict is found between two or more planned outage schedules, Grid West will give priority to the request with an earlier submission date if their impacts to reliability are similar and if other factors do not overrule. The timing requirements for Grid West's evaluation have not been defined, but will be compatible with the general timeline set forth by NWPP.

When Grid West determines there are reliability concerns in the proposed transmission outage schedules, Grid West will develop an alternative transmission outage proposal to relieve those concerns. Grid West will work with the transmission facility owners to discuss the proposal and help implement the alternative outage schedules. Grid West may approve or deny the initial request if such an approval authority is vested in the Transmission Agreement, but will provide a reasonable alternative for the rejected outage schedule(s).

Grid West will continue to work with regional stakeholders to improve the transmission outage coordination process in order to minimize any negative impacts of transmission outages. Grid West's future improvements may include:

- Transmission outage coordination at the seams, such as with the Pacific AC and DC ties and among different transmission systems; and
- Potential modifications in the timeline in order to provide for more thoughtful analysis and comment before transmission outage plans are finalized.

5.5 Publishing of Transmission Outage Plan

Grid West will publish the initial transmission outage plan for facilities under its control 30 days before the month in which the outage will occur. Grid West will publish the final transmission outage plan 15 days before the month in which the outage will occur. In addition, NWPP may also publish the approved transmission outage plan for the entire region of the NWPP members.

6.0 GENERATION OUTAGES

6.1 Notifications of Generation Outages

Grid West will make available a generation outage notification form to be used by generation owners to submit or change notification of generation outage schedules.

Generation owners will be asked to submit their planned generation outage schedules at least 45 days ahead of the outage for all generators with a given MW nameplate capacity for the current and next calendar years (threshold to be determined). Grid West will not make generation outage information public.

6.2 Data Needed for Generation Outages

A generator outage notification should include the following information:

- Generating unit name and its Grid West reference code;
- Nature of the generation outage and maintenance to be performed;
- Unavailable MW capacity;
- Start date, end date and time of the planned generation outage;
- Flexibility data, if any (e.g. alternative periods of generation outage, time required to terminate the generation outage and restore the unit to normal capacity);
- Contact information; and
- Interdependencies or associations with other work or outages.

6.3 Review of Generation Outages

Grid West will assess the reliability impact of submitted outage notices.

When Grid West determines there are potential reliability impacts associated with the proposed generation outage schedules, Grid West will:

- Notify the generation owners and may seek to negotiate alternative outage schedules if possible.
- Take necessary measures to mitigate the concerns not resolved by negotiations with generation owners, such as derating the impacted flowgates, etc.

7.0 FORCED GENERATION AND TRANSMISSION OUTAGES

For forced outages within the Consolidated Control Area (CCA), Grid West will request immediate notification of all forced outages (unplanned outages) of both generation and transmission resources after they are identified. The facilities' owners will report generation and/or transmission outage details to Grid West using Grid West's outage notification system or other systems if appropriate.

For forced generation and/or transmission outages outside the CCA but within the GWMT, the host balancing area and Grid West will both be notified immediately. Grid West will work with the host balancing areas to develop a reporting requirement for all forced outages of both generation and transmission resources.

8.0 INFORMATION DISSEMINATION

Grid West will publish proposed and approved outage schedules of transmission facilities (subject to security consideration).

Grid West will also determine the level of transmission outage information to be exchanged with other control areas in the region.

Grid West will not reveal any specific information on generator outages.

9.0 IMPACT ON OTHER GRID WEST PROCESSES

Once transmission and/or generation outage plans or actual outages are known, Grid West will need to account for their impact on other modeling and processes as part of the approval and coordination process. For example, the Rights Translation and Reconfiguration Service (RCS) will need to use the updated Available Flowgate Capacity (AFC) data. Other models and processes (such as the determination of x-factors or non-firm sales) possibly affected by the change of AFCs are to be determined.

10.0 ROLES & RESPONSIBILITIES

10.1 Grid West's Responsibilities

Grid West will:

- Make available outage notification systems for generation and transmission facility owners to send outage schedules to Grid West;

- Develop the criteria of transmission outage evaluation;
- Manage outage notification system;
- Evaluate planned outages and develop alternatives to the proposed outages if negative impacts are identified;
- Accept or reject schedules for planned outages of transmission facilities in accordance with the terms of the contractual agreement between Grid West and the Transmission Owners;
- Post approved schedules for planned transmission facilities outages;
- Establish and implement record keeping procedures for the retention of all requested planned outages and forced outages; and
- Perform the functions associated with supporting the NWPP Coordinated Outage Process.

10.2 Facility Owners' Responsibilities

Transmission and generation facility owners will be asked to:

- Notify Grid West of planned outages through the outage notification system whenever they are identified;
- Notify Grid West of forced outages in the CCA whenever they are identified; and
- Report forced transmission outages and generation outages, if they are known.

11.0 MARKET BENCHMARKS

Outage coordination is a standard process used by nearly all RTOs in North America. Some differences lie in the specific timing requirements and procedures related to Grid West's unique market structure as listed in Table 11.1.

Table 11.1 -- Outage Coordination Benchmark

Process	Grid West	Other RTOs/ISOs
Notification requirements	Yes	Yes
Generation outage approval authority	No, but voluntary information sharing with generators will be sought.	No
Transmission outage final approval authority	Based on contractual agreement between Grid West and TOs	Yes
Yearly generation maintenance plan requirement	Not used [Grid West will collect longer term outages (beyond 120	Some

	days) in advance and share them with stakeholders if possible.]	

12.0 TECHNOLOGY SOLUTIONS

The major components of the outage notification system are:

- Outage notification system and Web interfaces;
- Off-line study tools and databases for outage evaluation;
- Interface to move data from the offline outage notification to the Grid West rights administration database; and
- Interfaces with NWPP.

13.0 COST DRIVERS

The primary cost drivers for interchange implementation relate to the required software systems and personnel requirements. Cost drivers include:

- Number of planned outages to evaluate;
- Number of outage requests requiring proposed changes;
- Complexity of analysis typically required;
- Posting frequencies; and
- Record-keeping requirements.

14.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Exchange of transmission outage information between Grid West and other control areas* - The extent of information exchanged is to be determined between control areas.
- *Reliability and other criteria of transmission outage evaluation* - Grid West will need to clarify details of reliability evaluation methods and the market value determination for transmission outage evaluation.
- *Grid West's role as outage facilitator or approval authority* - The details of Grid West's roles should be clarified in developing Grid West's transmission agreements.
- *Outage rescheduling costs* - Costs associated with outage plan modifications.

1.0 EXECUTIVE SUMMARY

When Grid West's Injection/Withdrawal Right (IWR) Transmission Customers submit balanced energy schedules to Grid West, they are responsible for losses associated with their transmission use. To meet this responsibility, they will need to schedule losses during the day-ahead scheduling process.[1]

Highlights of the proposed loss methodology include:

- Pre-existing transmission service rights and their associated loss provisions will be honored;
- Grid West's loss methodology will apply only to IWR schedules;
- Ex-ante loss factors will be used for IWR schedules;
- A simplified loss methodology will be used by Grid West for developing the IWR loss factors;
- The loss methodology will recover expected average, not marginal, losses; and
- IWR Transmission Customers will provide concurrent losses in the day-ahead scheduling process.

2.0 PURPOSE

This white paper discusses the proposed Grid West loss methodology to be applied to IWR schedules. It attempts to satisfy the objectives established by the Regional Representatives Group (RRG). The objectives of the loss methodology are:

- Minimize cost shifts;
- Maintain loss provisions of pre-existing transmission service rights and obligations;
- Create a reasonable match between loss collection mechanisms and actual loss effects on the transmission system;
- Use ex ante loss factors to provide certainty to Transmission Customers in advance;
- Eliminate multiple loss charges (i.e. multiple loss charges for a single transaction) for IWR schedules within the Grid West Managed Transmission (GWMT) system; and

[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.

- Be equitable and easy to implement and consistent with the scheduling model.

In practice, not all objectives can be achieved simultaneously because of inherent conflicts in the objectives. This paper proposes a simplified approach as a starting point. Future improvements could be considered and phased in later.

3.0 BACKGROUND

Currently, pre-existing transmission rights include loss provisions. These loss provisions will not be altered by Grid West. The loss factors and the receipt of energy scheduled to meet loss responsibilities will continue to be governed by the pre-existing arrangements.

Grid West will meet requests for additional transmission service over the GWMT. Grid West service will be in the form of IWRs acquired, for instance, through the Reconfiguration Service (RCS). As with pre-existing rights, users of IWRs will have a responsibility for system losses. However, since IWRs are issued from the combined systems that make up the GWMT, no single company loss factor will apply to IWRs. For this reason, a new loss methodology is needed for use with IWRs.

Developing a new loss methodology is challenging for the reasons that follow:

- Transmission losses are not linear; they vary with the square of the current; and
- Transmission losses are a result of the simultaneous activities of all users of the transmission system.

As a result, it is not possible to know in advance the loss effects of specific transactions. Instead, estimated loss factors are used to allocate losses to Transmission Customers based on a measure, in some manner, of their expected usage. [I think this is what it is supposed to mean—Linc.]

Given the scope of Grid West, some concern has been expressed that a single number for all of the GWMT for all hours would not be very accurate. At the same time, a complex loss factor method would impose a burden on the users of the system. The loss methodology to be suggested for use with Grid West IWRs strikes a balance between two competing interests – accuracy and simplicity. It is suggested here that the Grid West IWR loss factors be developed based on marginal loss information, scaled down to recover estimated overall losses, in a manner that has been simplified to a reasonable number of time periods per year and to generalized locations. [Is two dozen “few?” We need to leave open the

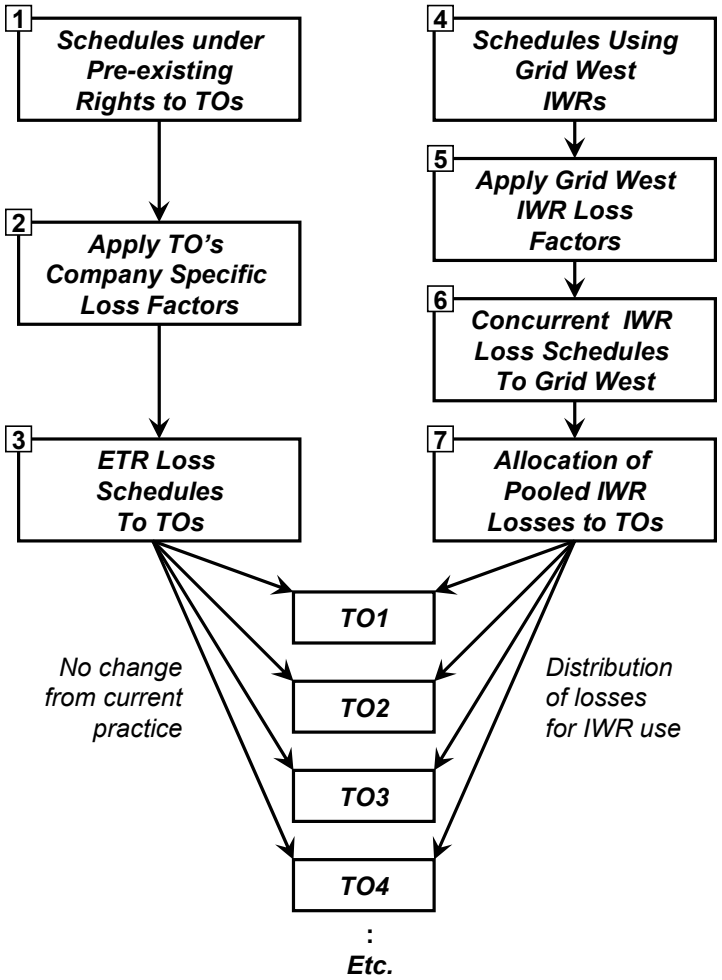
possibility of 24 time periods a year.] This approach retains a measure of the locational and timing accuracy benefits of marginal losses, but minimizes over collection.

4.0 LOSSES FOR PRE-EXISTING RIGHTS

Based on the Regional Proposal, the loss requirements for Transmission Customers with pre-existing transmission rights agreements will not change. The losses provided and the methods of delivery to Transmission Owners (TOs) will be unchanged from current practice. Retaining current provisions will prevent a cost shift that would occur if there was a change in loss responsibility for pre-existing services. Loss scheduling practices, whether concurrent, delayed or financially settled, will also remain under the provisions of pre-existing agreements. Since the great majority of use of the GWMT in the early years of Grid West is planned to fall under these pre-existing agreements. some Transmission Customers will not have a substantial impact.

5.0 DAY-AHEAD SCHEDULING

Figure. 5.1 -- The Grid West Loss Collection and Allocation Process



Losses are provided in the day-ahead scheduling processes as depicted in Figure 5.1 above. Boxes 1-3 in the figure depict scheduling of pre-existing transmission rights, as follows:

- Transmission Customers with pre-existing rights submit their schedules to the TO who issued those rights;
- The applicable company loss factor for the TO is applied to the energy schedule to produce the required losses to be supplied to the TO; and
- The Transmission Customer submits a loss schedule to the TO, according to the provisions of the pre-existing agreement—for example, 168 hours later so specified.

- The TO is responsible for deviations between the losses provided by Transmission Customers and the actual expected losses on its system.

Since the loss schedules go directly to the TOs as they do today, there is no shift in loss responsibility for system usage that is based on the use of pre-existing rights. Boxes 4-7 of the figure depict the scheduling of IWRs issued by Grid West, as follows:

- Transmission Customers using IWRs submit their schedules to Grid West.
- The appropriate Grid West loss factor is applied to each IWR schedule.
- The Transmission Customer submits a *concurrent* loss schedule to Grid West, i.e., the losses are not submitted on a delayed basis but are provided at the time of scheduling.
- Grid West pools the loss energy scheduled to it by IWR users and allocates that pool back to the Transmission Owners in *concurrent* loss schedules.

The concurrent loss scheduling requirements should be noted, since they differ from the practice of some Transmission Owners today. Grid West will have no energy resources of its own. As a result, concurrent loss scheduling is desired to avoid a situation where Grid West would have to buy energy to meet losses in high-load periods and sell energy to dispose of extra energy in light-load periods.

The methodology for development of the loss factors (box 5) and for allocation of losses among the TOs (box 7) is described in Section 6.0 below. An IWR Transmission Customer's loss obligations can be met either directly or indirectly.

- ***Direct:*** Transmission Customers submit a separate concurrent loss schedule for the losses attributed to their aggregate schedules as shown above.

- ***Indirect:*** Third-party loss providers submit a concurrent loss schedule on behalf of the Transmission Customer for the losses attributed to their aggregated schedules.

In any ex-ante loss factor method, there is a difference between the losses scheduled and actual losses incurred in real-time operation. Today, the transmission owner makes up the difference, supplying energy when actual losses are greater than scheduled losses (heavy load periods) and absorbing energy when scheduled losses exceed the actual losses (light load periods). This scheduled loss to actual loss difference will continue to be made up by the individual TOs for Grid West IWR service. More details and illustrations are provided in Appendix C to demonstrate that loss responsibility is not shifted by the Grid West methodology.

6.0 LOSS METHODOLOGY DESCRIPTION

The Grid West loss methodology for IWRs has three components: (1) ex-ante loss factor computation, (2) loss obligation determination, and (3) allocation of loss schedules to balancing areas. Each of these components is covered briefly in this section. The attributes of the proposed methodology are further discussed in Appendix A. The volume of loss collections for IWR use is likely to be relatively small compared to the losses collected for pre-existing agreements. While the overall effect of the new methodology will grow over time, its initial impact is likely to be incremental. As experience is gained with the new method, it may be able to be modified to correct concerns that may arise. Such a change may require, however, a Special Issues List vote of the members.

Ex-Ante Loss Factor Computation: Grid West will use ex-ante loss factors to calculate loss obligations for schedules using IWRs. Ex-ante loss factors will provide Transmission Customers with certainty in energy scheduling. In order to calculate these loss factors, Grid West will use a power flow model based on various operating scenarios (e.g. Peak, Off-Peak, seasons, etc.). Based on these detailed loss factors, Grid West will develop a set of aggregated loss factors that have some degree of time and location variation that balance the competing desires for accuracy and ease of use. In practice, the degree of granularity should be determined based on detailed studies conducted prior to implementation. The study results will provide a basis for determining how much error is introduced by a given level of aggregation.

Loss Obligations Determination: Grid West will provide the loss factors to Transmission Customers through the Market Information System (MIS). The Transmission Customer (and Grid West) will calculate the loss obligation for each submitted schedule using IWRs. The loss obligations for a Transmission Customer are accumulated for the scheduled transactions. A Transmission Customer or its loss provider should submit a separate concurrent loss schedule to Grid West as part of the day-ahead scheduling submission process.

Allocation of Loss Schedules to Balancing Areas: Grid West will manage transmission losses at the GWMT level as part of the day-ahead process. Transmission Customers are not required to provide losses at a specific bus or within a specific balancing area. In other words, delivery location of the scheduled losses can be to any point within or on the boundary of GWMT system.[2] As more fully described in Appendix C, the real-time losses in each balancing area are part of the total load within the balancing area. As tie-line

[2] However, if experience with the new methodology demonstrated a need for locational delivery of losses, procedures will be developed at that time to address the need.

metering is used to hold the net schedule interchange with North American Reliability Council (NERC) requirements, variances in losses and real-time load are met simultaneously. A huge investment in metering would be required to actually separate losses from load in real time. Instead, each Transmission Owner covers the loss variance as part of its total load.

The loss schedules provide in-kind compensation to the Transmission Owner for providing this service, i.e., providing extra energy when losses are higher than the scheduled losses and absorbing energy when the reverse is true. Over time, the in-kind contribution is intended to balance out the balancing authorities' cost. When losses are scheduled directly to the Transmission Owner, as described above for losses for pre-existing rights, there is no need to allocate losses among the Grid West Transmission Owners. This allocation is accomplished through the use of interchange schedules.

After receiving the loss schedules from Transmission Customers, Grid West will create interchange schedules to allocate the IWR loss collections among the balancing areas within the GWMT. Within the Consolidated Control Area (CCA) operated by Grid West, the losses allocated to the CCA will be further allocated to the consolidating Transmission Owners (or their load-serving entities), where the allocated share of the IWR losses will become part of the total energy input used to settle imbalances. The end results of loss allocation schedules will be that all balancing areas within the GWMT will receive their share of expected losses associated with IWR use. An example is given in Appendix B to illustrate how this loss allocation schedule is to be achieved.

The allocation factors for distributing IWR loss collections among balancing areas (and CCA Transmission Owner/load-serving entity load areas) will be based upon power flow modeling. One proposal is that the IWR losses be allocated based on the power flow estimate of percentage of actual losses in each balancing area (or Transmission Owner load area for the CCA). Another possibility to be considered is using the percentages of the incremental losses for each area attributable to IWR use. The details of the allocation procedure will be evaluated with quantitative analysis before startup in order to determine which of these methods (or perhaps another method) is preferable. Since IWR losses are incremental above the pre-existing losses, the allocation of IWR losses among the areas is not a matter of cost shifting unless there is a mismatch between the allocation and incurrence of IWR losses.

7.0 ROLES AND RESPONSIBILITIES

7.1 Grid West's Responsibilities

Grid West will:

- Calculate and publish applicable loss factors for IWRs at a reasonable time before the scheduling process; such a publication might be in the form of a matrix of loss amounts between injection and withdrawal areas (or points).
- Evaluate loss obligations of IWR Transmission Customers for all submitted day-ahead schedules;
- Determine the IWR loss allocation factors for distributing loss schedules among balancing areas;
- Create interchange loss schedules to implement the allocation.

7.2 IWR Transmission Customers' Responsibilities

IWR Transmission Customers will:

- Meet their loss obligation by submitting loss schedules either directly or through third-party loss providers.

7.3 Loss Providers' Responsibilities

Loss providers will:

- Schedule the loss obligations for IWR Transmission Customers that they represent.

Loss providers may:

- Represent multiple Transmission Customers if they choose.

7.4 Existing Transmission Owners' Responsibilities

Existing Transmission Owners will:

- Act as the default loss providers for Transmission Customers that have pre-existing transmission service rights agreements, subject to the provision of losses by the Transmission Customers in accordance with those agreements.
- Act as the swing provider for the variance between loss factors and hour-to-hour losses, as they do presently, providing the shortfall in high loss hours and absorbing the overscheduled loss amounts during low loss hours.

8.0 MARKET BENCHMARKS

One fundamental difference exists between Grid West and existing RTOs. The day-ahead regional services and loss schedules cover the GWMT while the real-time markets cover only the CCA. In most RTOs/ISOs, there are day-ahead and real-time markets that have the same geographical boundaries. Except for this difference, many similarities can be observed from the existing business practices for losses among the existing RTOs and ISOs in North America. A comparison of the proposed loss methodology with the loss methodology of existing RTO/ISOs is given in Table 8.1 below.

Table 8.1 -- A Comparison of Loss Methodology with RTOs/ISOs

Loss Methodology Attributes	Grid West proposal	CAISO Current	ERCOT	LMP markets (NYISO/MISO CAISO future[3])
Ex ante vs. ex post	Ex ante	Ex ante and ex post (hour-ahead) true up	Ex ante	Ex post for financial settlement. The quantity may be ex ante.
Pre-existing transmission service rights agreement	Each TO will be responsible for recovering any losses mismatch[4]	Each TO will be responsible for recovering any losses mismatch		In MISO, transmission customers settle directly with MISO with marginal losses rebated to existing contract holders
In-kind Loss Return option	None for IWRs; existing contracts may allow such returns	No	No	Some
Locational signal	Partial	Partial	Partial	Yes
Loss factor calculation	Scaled marginal	Scaled marginal	Scaled marginal	Marginal
Loss factor granularity	Monthly (or some other time period) peak and off-peak	Hourly	Seasonal peak and off-peak as base and extrapolation to 15 minutes interval.	Hourly

[3] CAISO will implement LMP-based loss methodology soon.
[4] This mismatch is the difference between the total losses scheduled and the total losses computed using power flow. Also see discussion in Appendix C.

Loss Methodology Attributes	Grid West proposal	CAISO Current	ERCOT	LMP markets (NYISO/MISO CAISO future[3])
Over collection	No	No	No	Yes

9.0 TECHNOLOGY SOLUTIONS

The implementation of the loss methodology is a scheduling function of Grid West operations. There are no specific technology components for the loss implementation since the loss methodology is embedded in the scheduling and settlement systems. The major elements of the impact to the overall technology solution are:

- Power system modeling software,
- Scheduling system,
- Settlement system and
- OASIS posting

11.0 COST DRIVERS

The primary cost drivers for loss methodology implementation relate to the complexity of the solution. For example, the costs will be reduced if Grid West:

- Uses the simplified methods with long-term (year or season) and area loss factors.

On the other hand, the costs will increase if Grid West:

- Develops power models and computes loss factors to account for all the delivery periods;
- Includes a loss true-up process; or
- Assumes the responsibility of the mismatch of pre-existing contractual losses and loss obligations defined in this proposal.

12.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

- *Avoidance of unintended consequence of "cherry-picking" by pre-existing transmission service rights holders.* When an existing transmission contract holder assesses the benefits of holding onto its existing contract or terminating it in order to obtain standard IWR rights, it would probably consider the difference between company loss factors for pre-existing rights and the newer IWR loss factors. If this

option is available to the contract holders, the difference in loss obligations may be sufficient to induce a contract holder to selectively switch the pre-existing contracts to standardized IWR rights, all other factors being equal. This creates the possibility for cost shifting between the Transmission Owners because the loss allocations for IWRs will not match the pre-existing loss collections. Grid West will need to consider appropriate measures to avoid such unintended consequences as part of its overall consideration of rollover of pre-existing contracts, requests for new service, ability to offer into the RCS markets, etc.

- *"No charge" transmission reservation.* In the current practice of many Northwest utilities, loss–return schedules enjoy the benefit of not needing transmission rights with associated charges. It is not clear whether such a benefit should be maintained for loss provisions by IWR Transmission Customers in their loss–provision schedules.
- *Treatment of curtailments*. If some day-ahead schedules are infeasible after the TOs have adjusted for their existing-contract use, Grid West may have to adjust or reject proposed transactions. The adjustments or rejections may impact the loss obligations of the Transmission Customers. At this time, it is unclear whether such an iterative process should be developed.
- *Use of area loss factors.* Caution must be exercised in defining areas, because the use of very large areas will blunt any accuracy gains for loss responsibility from the new methodology.

APPENDIX A: PROPERTIES OF THE PROPOSED LOSS METHODOLOGY

The following sections describe some of the attributes of the proposed loss methodology.

A.1 Additive Property

The additive property of a loss methodology (also having been called transitiveness) measures if two equal and opposite transactions will cancel out one another's flows and the associated loss obligations. The proposed loss factor is additive since it conforms to the objective to reflect the actual costs of transactions. For example, if there are two transactions with same quantities from A to B and from B to C, a loss methodology with additive property will result in the same amount of loss obligations as a transaction from A to C while a non-additive loss methodology will generally not.

The additive property has another advantage in that it encourages power supply and load proximity (including swapping), all else equal.

The additive property is generally preserved for the Locational Marginal Pricing (LMP) type loss methodology that has been adopted in several RTO/ISOs.

A.2 No Multiple Loss Charges

Multiple loss charges of a single transaction have been generally regarded as detrimental to economic efficiency. Multiple loss charge refers to the payment of multiple transmission rates for one transaction (e.g. a transaction scheduled across multiple transmission systems with a cost to use each one). There is a major distinction, however, between multiple transmission rates and losses. Losses are a real variable cost of production, while transmission rates reflect usually the fixed cost of a transmission system. Because losses are a real variable cost of production, the proposed loss methodologies should be designed to be an improvement upon the traditional pancaked loss charges.

For transactions involving external control areas, Transmission Customers are responsible for their external losses. The seams issues related to losses remain to be resolved.

A.3 Locational Loss Signals

Although the proposed loss methodology is not directly distance sensitive, it is location dependent. The loss obligations of a transaction depend on the loss factors at its Injection Point and Withdrawal Point, thus leading to locational effect of loss obligations. The result is sensitive to relative impedances, predominant flow patterns, etc., in addition to the raw geographic distance between two points.

A.4 Attributes Summary of the Proposed Loss Methodology

The following table shows how the proposed loss methodology addresses the objectives.

Table A.4 -- Attributes of the Proposed Loss Methodology for IWR Schedules

Objectives	Proposed methodology	Comments
Pre-existing rights honored	Yes	Otherwise, costs shifts are unavoidable.
Actual losses reflected (minimize cost shifts)	Strong cost causation to transactions.	It is difficult to have a qualitative measure for this objective, but the additive property and strong locational and timing signals in the proposed methodology will result in more accurate loss recovery. A mechanism is needed to avoid cost shifting between Balancing Areas and their customers, as well as the cost shifts in real-time operations (see Appendix C).
Multiple loss charges eliminated	Yes	Within GWMT for IWR usage.
Losses certainty	Yes	No true-up is proposed.
Additive (Transitive) property	Yes	Reflect actual costs more accurately, if cost shifts are allowed, because some will pay more and some pay less to ensure that the same level of losses is collected (assuming loss measures are accurate today).
Easy implementation consistent with economic objectives	Yes	See implementation details that are presented as part of the proposed methodology.
Consistency with market operations	Yes	See implementation details that are presented as part of the proposed methodology.

APPENDIX B: EXAMPLES OF ONE LOSS ALLOCATION METHOD OF IWR LOSS COLLECTIONS FOR DAY-AHEAD SCHEDULING

Assuming that Transmission Customers in the day-ahead scheduling process have delivered the loss obligations for IWRs to Grid West, we illustrate the loss allocation scheduling method to balance the loss obligations for IWRs among different balancing areas in the GWMT.

In this example, we further assume there are only three balancing areas (A, CCA and B) whose configuration is given in Figure B.1.

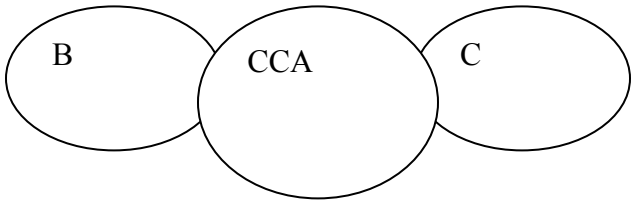


Figure B.1 -- Example Configuration of Balancing Areas

As shown in Table B.1, the losses computed by the power flow model are 300, 200 and 100 MWhs for balancing areas CCA, B and C, respectively. These calculated losses are the target values for each balancing area to receive[5]. Assume that 60 MW were collected by Grid West from users of IWRs. The allocation factors and the MW schedules are shown in Table B.1.

Table B.1 -- Example of Loss Reallocation Data

Balancing Area	Estimated Losses as computed by Power Flow	Allocated share of IWR losses to each Balancing Area	Loss Schedule from Grid West to Balancing Area
CCA	300	50%	30 MW
B	200	33%	20 MW
C	100	17%	10 MW

[5] Small loss errors between actual losses and computed losses are expected. The system balance is maintained by real-time balancing resources to meet aggregated loads and losses. The loss errors between balancing areas will be part of the unaccounted-for-energy (UFE) accounting.

APPENDIX C: EXAMPLES OF LOSS PROVISIONS BY TOs

C.1 Current Loss Provision by TOs

An example in Figure C.1 is a typical situation where a Transmission Customer TC1 pre-schedules energy for both its load and losses from a source beyond its meter (G2). In real time, the net outflow/inflow at the balancing area boundary is deemed delivered. The difference of the measured values by interconnection meters (M4, M6 and M7) and the scheduled value is treated as inadvertent energy and dealt with separately between the balancing authorities. G3 is dispatched in real time to cover any imbalance within the balancing area. Within the balancing area boundary, the composite load (customer load plus losses) is equal to the sum of generation (meters M2+M3) less the interchange that flows across balancing area boundary (meters M4+M6+M7)[6]. Loss schedules supplied by Transmission Customers are energy sources used by the balancing authority to meet the composite load, and the balancing energy adjustments made by the operator will simultaneously meet both the variance of load from pre-schedule and the variance in losses from the loss factors used to calculate loss schedules. The responsibility for under/over collection between actual losses and average loss factors falls to the balancing area operator.

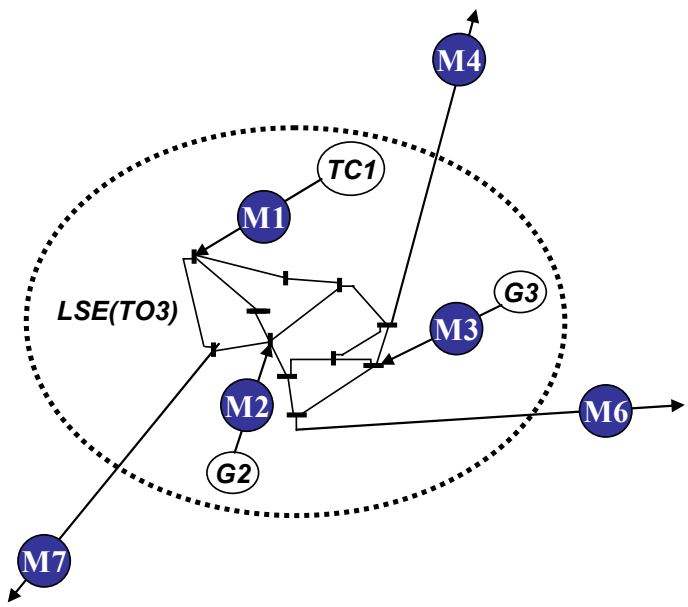


Figure C.1 -- A Single Balancing Area with Control Metering Shown for the Load Serving Entity of Transmission Owner 3 Labeled as LSE (TO3).

[6] Interchange assumed to be positive for exports

C.2 Loss Provision by the LSEs of Transmission Owners under Grid West

Under Grid West, each balancing authority will be in the same position with regard to metering as exists for today's transmission provider control areas. Figure C.2 depicts a situation where today there are three control areas, but after Grid West forms, two of the control areas choose to join the CCA while one of the control areas wishes to continue to operate a separate balancing area within Grid West. The separate balancing area, LSE (TO4), will continue to be the swing provider of losses in real time within its boundaries.

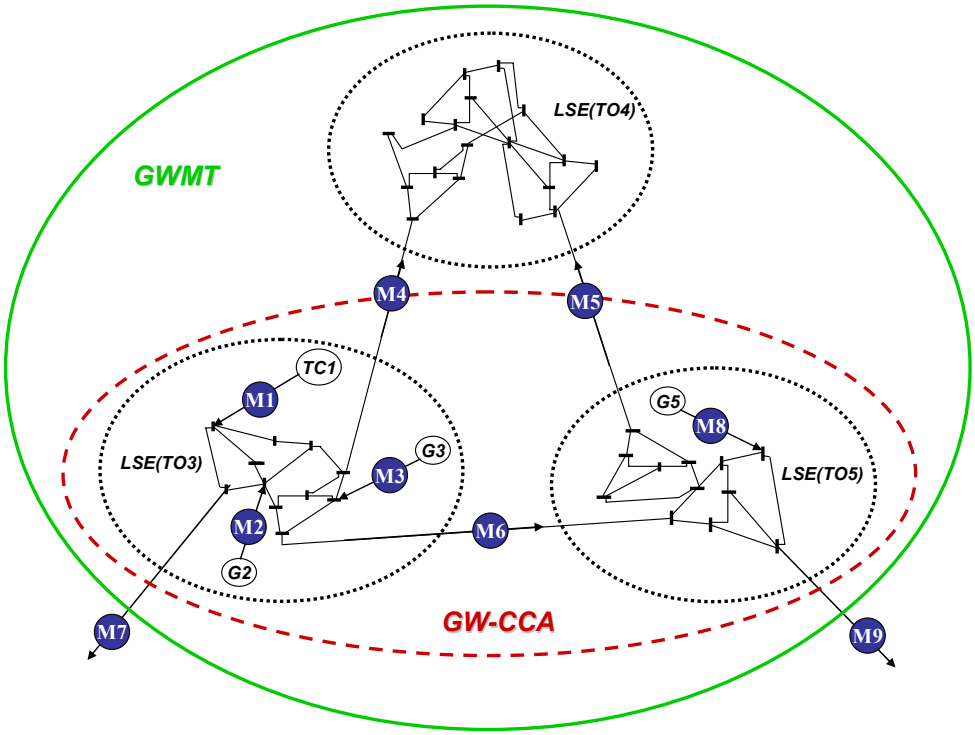


Figure C.2 -- Grid West Balancing Areas with Metering Shown for CCA.

This consolidation of balancing authorities into the CCA raises a question, "How will the loss mismatch be handled within the CCA balancing area and allocate that responsibility among the consolidating parties?" As in Section C.1 above, the answer to this question lies in understanding the nature of the existing metering scheme and how it would be applied within the CCA. The balancing actions of the operator for the CCA will be the same as those described above for other Grid West balancing areas. As the operator of the CCA, Grid West will use the Real-Time Balancing Service to meet load and loss variance from schedules. In doing this, it is also the swing loss provider for the CCA.

Continuous dispatch adjustment of balancing resources (G3 and G5) will ensure the total generation (G2, G3 and G5) will meet the aggregate load, losses and scheduled net interchange at the CCA boundary (meters M4, M5, M7 and M9). The composite load within the Grid West CCA boundary will be the sum of internal generation (meters M2+M3+M8) less the net interchange (meters M4+M5+M7+M9).

The aggregated load and losses will be met within the CCA with balancing energy. Because the measurement of load for each LSE will continue to be based on the metering that existed when they operated separate balancing areas, the responsibility for losses will inherently remain with the same LSEs who carried that responsibility in the past. This can be seen by reference to Figure C2.

The composite load for LSE (TO3) will be equal to the generation injected (meters M2+M3) less the energy flowing out across the metered boundary (meters M4+M6+M7). This will be the same composite load that would have been measured had LSE (TO3) not joined the CCA. Thus the responsibility for losses within the metered boundary will remain the responsibility of LSE (TO3), i.e., the responsibility of each party who chooses to consolidate will remain unchanged. The energy pre-scheduled to Grid West as IWR loss schedules and allocated to each LSE (see Section C.3 below) and the energy received from Transmission Customers using pre-existing transmission rights will net against the actual imbalance of each of the LSEs within the CCA when net imbalance is determined.

(This page intentionally blank)

OPERATIONS – MODULE 3b

NERC Reliability Functional Model – Describes proposed roles and responsibilities for Grid West and participants to meet the requirements of the NERC reliability functional model.

Real-Time Monitoring – Describes the proposed real-time monitoring process including the data needed to support both reliability and market functions.

Real-Time Balancing Service – Describes the operation of the balancing service used to obtain real-time Interconnected Operations Services for the CCA, while accounting for the nature and types of energy offers and selection of resources. It also describes the dispatch processes for resources selected by Grid West for the Real-Time Balancing Service including dispatch granularity, dispatch frequency, control signals process and routing, etc.

Emergency Operations – Describes the proposed emergency operations roles and responsibilities of Grid West for the GWMT as a Transmission Authority. The topics covered include emergency conditions, operating limits, NERC standards, the NWPP Energy Emergency Plan, and Grid West's operational responsibilities.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

The NERC Reliability Functional Model[1] (the Functional Model) defines the functions that must be performed to ensure the reliability of the bulk power system. The model is being developed in order to accommodate the changing organizational structures that did not readily fit into existing definitions of control area or other organization types. The model provides a framework of functions with clearly identified responsibilities that can be used for Reliability Standards and Compliance Measures developed through the NERC standards approval process. Reliability Organizations, such as control areas, Regional Transmission Organizations, etc., may perform one or more functions described in the model. Every geographic (electrical) area must identify the organization responsible for performing each of the reliability functions in the model. Key reliability, market operations and system operations responsibilities identified in the model include:

- Operating Reliability (Interconnection Reliability Authority)
- Interchange (Interchange Coordinator)
- Balancing (Balancing Authority)
- Transmission Service (Transmission Service Provider)
- Planning Reliability (Interconnection Planning Coordinator)
- Resource Planning (Resource Planner)
- Market Operations (Market Operator or Resource Dispatcher)
- Transmission Operations (Transmission Authority)
- Transmission Ownership (Transmission Owner)
- Generator Operation (Generator Operator)
- Distribution (Distribution Provider)
- Generator Ownership (Generator Owner)
- Purchasing-Selling (Purchasing-Selling Entity)
- Load Serving (Load-Serving Entity)
- Compliance Monitoring (Compliance Monitor)

A fundamental principle of the Grid West development proposal is to improve the reliability of the bulk power system in the region. To achieve this goal, Grid West will perform a number of reliability, market operations and system operations functions. This paper uses the Functional Model as a framework for identifying

[1] The terminology used here is based on the recommendations of The Functional Model – Reliability Standards Coordination Task Force as explained in Section 3 of this document. The task force's recommend terminology changes are being used because they make it easier to identify the roles and responsibilities of Grid West.

the reliability, market operations and system operations functions that will be performed by Grid West.[2]

Highlights of this paper include:

- The Pacific Northwest Security Coordinator (PNSC) will serve as the Interconnection Reliability Authority for the Pacific Northwest.[3]
- Grid West will serve as the Transmission Authority for the entire Grid West Managed Transmission System (GWMT) with operational responsibilities delegated to the Transmission Owners.
- Grid West will serve as the Balancing Authority and the Interchange Coordinator for the Consolidated Control Area (CCA).
- Non-consolidating control areas will serve as the Balancing Authority and the Interchange Coordinator for their respective areas.
- Grid West will serve as the Transmission Service Provider for the GWMT for new services (Injection-Withdrawal Rights). Transmission owners will continue to honor their existing contracts and will serve as the Transmission Service Provider under the terms of those agreements.
- Grid West will serve as the Interconnection Planning Authority for the GWMT.
- Grid West will serve as the Market Operator for the Reconfiguration Services for the GWMT.
- Grid West will serve as the Market Operator for the Real-Time Balancing Service and Reserve Markets for the CCA.
- Transmission Owners, whether consolidating or not, will serve as the Transmission Operator[4] for their respective facilities with some responsibilities delegated up to Grid West in its capacity as the Transmission Authority.
- Generation owning members, whether those that also own transmission facilities or IPPs, will serve as the Generator Operator for their respective facilities with operations coordinated through their host control area.

[2] 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] The exact nature of the relationship between the PNSC and Grid West needs to be defined further particularly with regard to governance, independence and duplication of effort. However, this objective is outside the scope of the TSLG.
[4] A Transmission Operator separate from the Transmission Authority is not identified in the draft Functional Model; however, for our purpose it is useful to also identify Transmission Operator function so that the division of duties between the owners and Grid West can be more clearly described.

2.0 PURPOSE

This paper describes the reliability, market operations and system operations responsibilities of Grid West in terms of the Functional Model. The paper provides an overview of Version 2 of the model, together with the changes recommended by The Functional Model – Reliability Standards Coordination Task Force, and uses it as a framework for describing the functions that Grid West will perform.

3.0 BACKGROUND

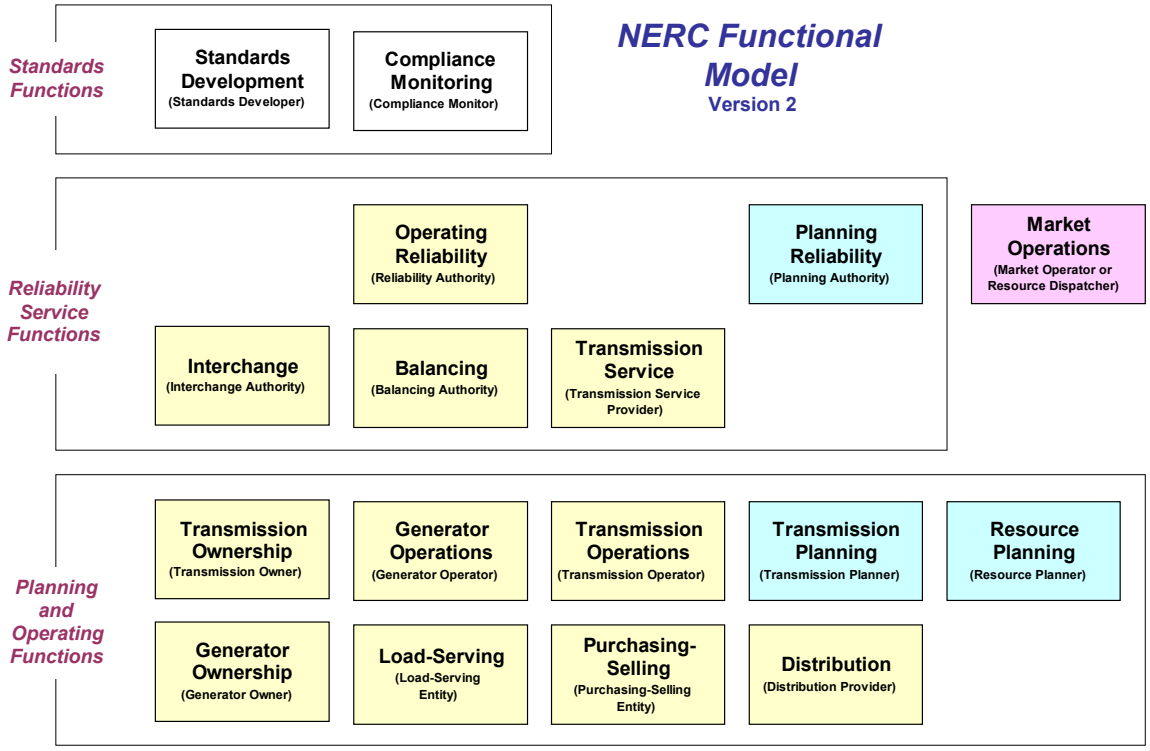
3.1 NERC Reliability Functional Model

The Functional Model is being developed, in part, to define the sets of functions that must be performed to ensure the reliability of the bulk power system. The model is not a standard, and does not incorporate any compliance requirements. However, it is being developed as the framework for the Reliability Standards being developed separately by other NERC initiatives. The model identifies the tasks being performed today for electric system reliability so that reliability organizations such as Control Areas, Regional Transmission Organizations, Independent System Operators and others can more easily and clearly identify the reliability functions they provide. These functions are defined in general terms, and the relationships between the entities performing the individual tasks within each function are defined at a high level. The model leaves it up to the individual organizations - whether traditional vertically-integrated control areas, regional transmission operators, independent system operators, etc. – to decide how to implement and which entities undertake the different responsibilities.

Version 2 of the Functional Model is illustrated in the diagram below[5]. As seen in the diagram, the functions are grouped into Standard Functions, Reliability Service Functions and Planning and Operating Functions.

[5] Source: NERC Reliability Functional Model Version 2

Figure 3.1 NERC Reliability Functional Model



The key reliability responsibilities identified in this version of the model are:

- Operating Reliability (Reliability Authority): Ensures the real-time operating reliability of the interconnected bulk electric transmission systems within a Reliability Authority Area.

- Interchange (Interchange Authority): Authorizes implementation of valid and balanced interchange schedules between Balancing Authority Areas, and ensures interchange transactions are properly identified for reliability assessment purposes.

- Balancing (Balancing Authority): Integrates resource plans ahead of time, and maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time

- Transmission Service (Transmission Service Provider): Administers the transmission tariff. Provides transmission services to qualified market participants under applicable transmission service agreements (for example, the pro forma tariff).

- Planning Reliability (Planning Authority): Ensures a long-term (generally one year and beyond) plan is available for adequate resources and transmission within a Planning Authority Area. It integrates and assesses the plans from the Transmission Planners and Resource Planners within the Planning Authority Area to ensure those plans meet the reliability standards, and develops and recommends solutions to plans that do not meet those standards.

Other functions identified in the model relevant to the discussion presented in this paper include:

- Market Operations (Market Operator or Resource Dispatcher): Integrates energy, capacity, balancing and transmission resources to achieve an economic, reliability-constrained dispatch of resources. The dispatch may be either cost-based or bid-based.

- Transmission Operations (Transmission Operator): Operates or directs the operations of the transmission facilities.

- Generator Operations (Generator Operator): Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.

Version 2 of the Functional Model was published in March 2004 and an extensive review period was conducted. Comments from the review period reflected among other things confusion regarding how some of the functions are implemented in practice in different organizations. They also reflected concerns regarding how to clearly delineate the boundaries between different functions and organizations so as to ensure that all the functions are properly covered.

Parallel to the development of the Functional Model, NERC developed and approved Version 0 of the Reliability Standards in early 2005 and they became effective April 1st, 2005. These standards are based on the Functional Model and include a number of the same functions described in it, e.g., Reliability Authority (Coordinator), Balancing Authority, Transmission Operator. During the development of these standards and the initial registration of the responsible entities, a number of issues and concerns that had previously been raised regarding the Functional Model, were raised again. As a result, the Functional Model – Reliability Standards Coordination Task Force was created with the charter to resolve these issues. This task force has issued a report [6] with

[6] "Recommendations to Facilitate Use of the Functional Model to Guide the Development and Application of Reliability Standards"

recommendations that greatly clarify/simplify the applicability of the Functional Model. In particular, the suggested recommendations make it easier to use the model as a framework for describing the functions that Grid West will perform. Recommendations in the report relevant to the use of the model in this paper can be summarized as follows:

- Titles of responsible operating entities described in the Functional Model should be revised to emphasize both the wide-area role of the reliability authority and the authority of the transmission operator for reliability within its responsibility area. For example, the Reliability Authority should be the "Interconnection Reliability Authority" and the Transmission Operator should be the "Transmission Authority".

- The Interconnection Reliability Authority definition, tasks and interrelationships in the Functional Model should be revised to focus on interconnection reliability and coordination of reliability among its transmission authorities.

- The Transmission Authority definition, tasks and interrelationships in the Functional Model should be revised to strengthen its authority and responsibilities to manage reliability within its area, subject to oversight by the Interconnection Reliability Authority looking at interconnection-related issues.

- The Planning Authority in the Functional Model should be named the "Interconnection Planning Coordinator." The definition, tasks and interrelationships of the Interconnection Planning Coordinator, Transmission Planner, Resource Planner and Transmission Owner should be modified as necessary to recognize that Transmission Planners, Resource Planners and Transmission Owners have certain authorities in the planning process. The Interconnection Planning Coordinator description should be revised to emphasize the wide-area oversight, coordination and integration of transmission and resource plans across systems.

- The Interchange Authority should remain in the Functional Model but should be renamed the "Interchange Coordinator." The Interchange Coordinator should be implemented in stages as driven by reliability need or business justification. The Interchange Coordinator definition, tasks and interrelationships should be modified to allow more flexibility and should be less prescriptive of a particular business model.

These suggested changes, as well as those suggested for the definition and tasks of the affected functions, have been incorporated into this paper.

4.0 GRID WEST'S RELIABILITY AND MARKET FUNCTIONS

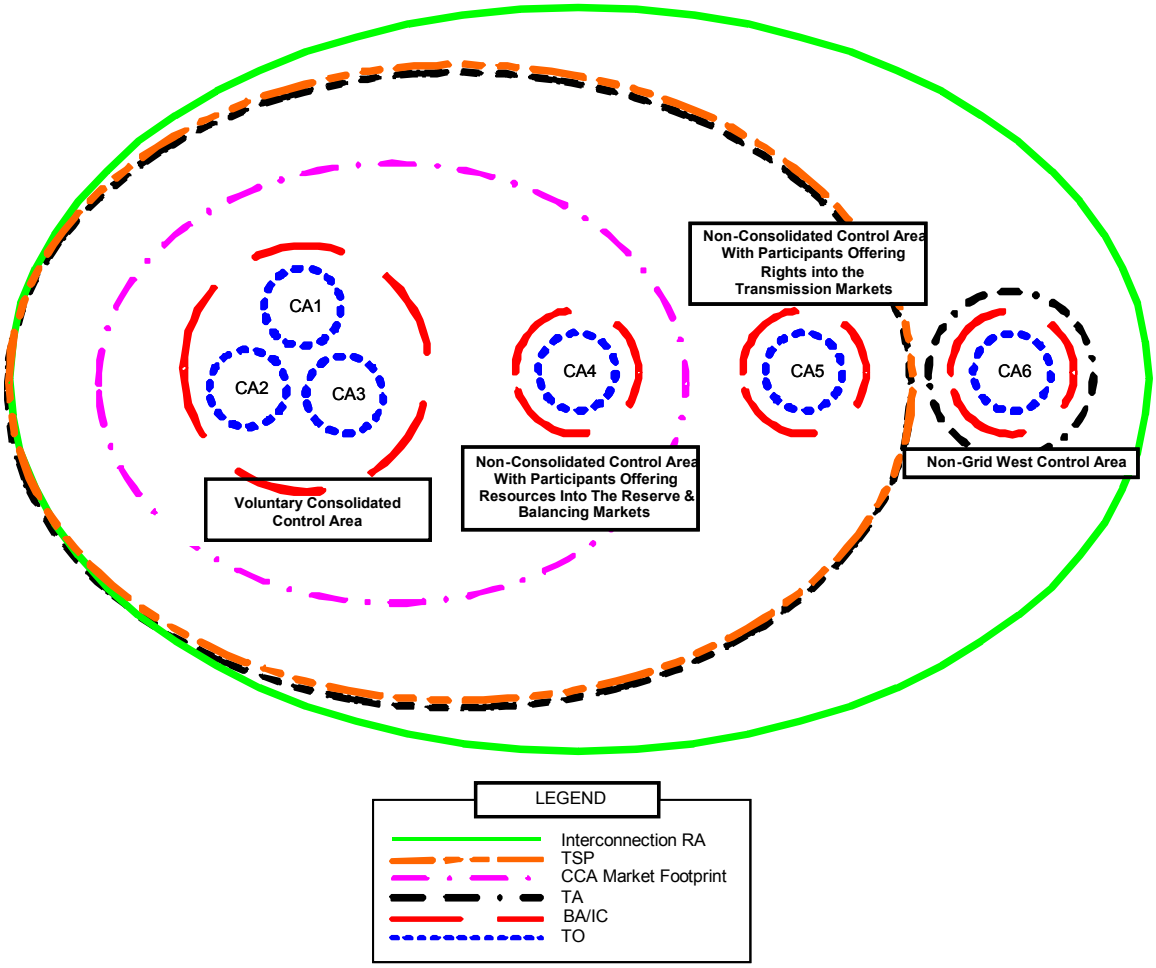
Grid West will be charged with transmission service provider responsibilities for the collective transmission facilities of its service area and the nondiscriminatory coordination of market transactions, system-wide transmission planning and network reliability (in coordination with the PNSC). Grid West will also operate a Consolidated Control Area (CCA) and administer a reserves market and real-time balancing service for those transmission-owning entities that choose to consolidate their control area operations.

Besides Grid West, there will be other entities responsible for reliability and system operations functions in the GWMT. These include:

- The Pacific Northwest Security Coordinator (PNSC)
- Transmission/Generation Operators/Owners that consolidate
- Transmission/Generation Operators/Owners that don't consolidate (including the control area responsibilities).
- Independent Power Producers

A high-level overview of the key reliability, system operations and market operations functions in the Grid West footprint is depicted in the diagram below.

Figure 4.1 Reliability, System Operations and Market Operations Responsibilities in Grid West



4.1 Interconnection Reliability Authority

The role and key tasks performed by the Interconnection Reliability Authority as defined in the Functional Model are summarized in the table below.

The PNSC will serve as the Interconnection Reliability Authority for the Pacific Northwest.

Currently, individual control areas throughout the region serve as the Reliability Authority for their own areas and the PNSC provides coordination

among the areas. This role is very similar to the Interconnection Reliability Authority role that the PNSC will serve under the new reliability standards.

Table 4.1 Interconnection Reliability Authority Role and Tasks

Function	Interconnection Reliability Authority
Role	Ensures the operating reliability of the interconnected bulk electric transmission systems within an Interconnection Reliability Authority Area and the Interconnection. Has the responsibility and authority to direct and coordinate all operating reliability functions within its area to maintain the reliability of the Interconnection.
Key Tasks	• Maintain reliability of the Interconnection Reliability Authority Area in accordance with Reliability Standards • Monitor and record reliability-related parameters as required for reliability analysis of the Interconnection and the Interconnection Reliability Authority Area • Coordinate revisions to generation and transmission maintenance plans and direct revisions within the Interconnection Reliability Authority Area to maintain reliability • Develop and communicate Interconnection Reliability Operating Limits • Perform reliability analysis (actual-contingency and post-contingency) for the Interconnection Reliability Authority Area • Assess Interchange Schedules and direct actions to protect the reliability of the Interconnection and interconnected transmission systems within an Interconnection Reliability Authority Area • Identify, communicate, and direct actions to relieve reliability operating situations and reliability limit violations in the Interconnection Reliability Authority Area • Direct and coordinate implementation of emergency procedures • Direct and coordinate System Restoration • Coordinate operations with adjoining RAs • Evaluate and coordinate operating plans within the Interconnection Reliability Authority Area

4.2 Balancing Authority

The role and key tasks performed by the Balancing Authority as defined in the Functional Model are summarized in the table below.

The Balancing Authority responsibilities in the GWMT will be split amongst several entities as follows:

- Grid West will serve as the Balancing Authority for the CCA
- The non-CCA areas will serve as the Balancing Authority for their respective balancing areas.

The Balancing Authority Area for Grid West will include the control area of all the transmission-owning entities that choose to consolidate their control area operations into the CCA. Initially, it is anticipated that three of the largest Grid West transmission owning members will be consolidating and an allowance will be made for others to consolidate or not as they choose. Key drivers for consolidation are improving the system reliability and operational efficiencies.

Currently, individual control areas throughout the region serve as the Balancing Authority for their own areas.

Table 4.2 Balancing Authority Role and Tasks

Function	Balancing Authority
Role	Integrates resource plans ahead of time, keeps actual interchange equal to its scheduled interchange and provides frequency bias obligation for its Balancing Authority in real time.
Key Tasks	• Must have control of any of the following combinations within a Balancing Authority Area: 1. Load and Generation (an isolated system) 2. Load and Scheduled Interchange 3. Generation and Scheduled Interchange 4. Generation, Load, and Scheduled Interchange • Calculate Area Control Error within the Balancing Authority Area • Review generation commitments, dispatch, and load forecasts • Formulate an operational plan (generation commitment, outages, etc) for reliability assessment • Approve Interchange Transactions from ramping ability perspective • Implement interchange schedules by entering those schedules into an energy management system for both AC system and DC ties • Provide frequency response • Monitor and report control performance and disturbance recovery • Provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks • Determine needs for Interconnected Operations Services • Deploy Interconnected Operations Services • Implement emergency procedures

4.3 Interchange Coordinator

The role and key tasks performed by the Interchange Coordinator as defined in the Functional Model are summarized in the table below.

This function was not made part of the Version 0 Reliability Standards and all its tasks were merged into the Balancing Authority.

Based on the Version 0 Reliability Standards, Grid West would serve as the Interchange Coordinator for the entire CCA as it also serves as the Balancing Authority. The assignment of these responsibilities may change as the definition of the roles and tasks of the function evolves further.

Table 4.3 Interchange Coordinator Role and Tasks

Function	Interchange Coordinator
Role	Receives approvals and communicates authorization to implement valid and balanced interchange schedules between Balancing Authority Areas, and ensures interchange transactions are properly identified for reliability assessment purposes.
Key Tasks	• Determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.) • Verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules • Collect and disseminate Interchange Transaction approvals, changes and denials • Authorize implementation of Interchange Transactions over both AC and DC interfaces • Enter Interchange Transaction information into Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection) • Maintain record of individual Interchange Transactions

4.4 Transmission Service Provider

The role and key tasks performed by the Transmission Service Provider as defined in the Functional Model are summarized in the table below.

Grid West will serve as the Transmission Service Provider for the GWMT for new services (Injection-Withdrawal Rights). Transmission owning members, whether consolidating or not, will continue to honor their existing contracts and will serve as the Transmission Service Provider under the terms of those agreements. Grid West will provide some of the required tasks for these services on behalf of the transmission owning members.

Currently, individual Transmission Owners throughout the region serve as the Transmission Service Provider for their own facilities.

Table 4.4 Transmission Service Provider Role and Tasks

Function	Transmission Service Provider
Role	Administers the transmission tariff and provides transmission services to qualified market participants under applicable transmission service agreements (for example, the pro forma tariff).
Key Tasks	• Receive transmission service requests and process each request for service

	according to the requirements of the tariff • Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS) • Approve or deny transmission service requests • Approve Interchange Transactions from transmission service arrangement perspective • Determine and post available transfer capability (ATC) values • Allocate transmission losses (MWs or funds) among Balancing Authority Areas • Coordinate with Transmission Planner and Interconnection Planning Coordinator to develop plans to accommodate transmission service requests that cannot be accommodated with existing planned facilities

4.5 Transmission Authority

The role and key tasks performed by the Transmission Authority as defined in the Functional Model are summarized in the table below.

Grid West will serve as the Transmission Authority for the entire GWMT. Transmission Owners will continue to have operational responsibilities for their facilities as directed by Grid West or per standing orders.

Currently, individual Transmission Owners throughout the region serve as the Transmission Authority for their own facilities.

Table 4.5 Transmission Authority Role and Tasks

Function	Transmission Authority
Role	Ensures the reliability of the bulk electric transmission system within a Transmission Authority Area. Has the responsibility and authority to direct and coordinate the operation of transmission facilities within its area to maintain the reliability of the bulk electric system.
Key Tasks	• Develop transmission operating and contingency plans and operate the system to ensure the reliability of the area in accordance with Reliability Standards • Determine and communicate System Operating Limits • Monitor and perform reliability analysis of the Transmission Authority Area • Implement detailed transmission maintenance schedules (dates and times) provided by the Transmission Owner • Adjust dc ties and phase shifters within the transmission area for those Interchange Transactions that include these facilities in the transmission path • Deploys reactive resources to maintain voltages within defined voltage limits • Provide telemetry of transmission system information in real time and historical operating information as required • Coordinate operations plans, reliability analysis, and operations with the Interconnection Reliability Authority, Balancing Authority, and other Transmission Authorities

	• Implement reliability measures as directed by the Interconnection Reliability Authority • Requests the Balancing Authority to adjust generation dispatch to relieve System Operating Limit violations • Approve or deny Interchange Schedules from a reliability perspective • Develop and implement emergency procedures • Develop and implement System Restoration Plan

4.6 Interconnection Planning Coordinator

The role and key tasks performed by the Interconnection Planning Coordinator as defined in the Functional Model are summarized in the table below.

Grid West will be responsible for transmission planning for the GWMT and will work with WECC, as appropriate.

Table 4.6 Interconnection Planning Coordinator Role and Tasks

Function	Interconnection Planning Coordinator
Role	Ensures a plan generally one year and beyond is available for adequate resources and transmission within an Interconnection Planning Coordinator Area. It integrates and assesses the plans from the Transmission Planners and Resource Planners within the Interconnection Planning Coordinator Area to ensure those plans meet the reliability standards, and develops corrective actions for plans that do not meet those standards.
Key Tasks	• Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy • Maintain and develop methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans • Define, collect or develop and share information required for planning purposes, including: 1. Transmission facility characteristics and ratings, 2. Demand and energy customer forecasts, capacity resources, and demand response programs, 3. Generator unit performance characteristics and capabilities, and 4. Long-term capacity purchases and sales. • Evaluate plans for customer requests for transmission service: 1. Evaluate responses to long-term (generally one year and beyond) transmission service requests. 2. Review transmission facility plans required for integrating new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems. • Review and determine TTC, IROL and SOL values (generally one year and beyond) as appropriate • Assess, develop, document and report on resource and transmission

	expansion plans: 1. Integrate and verify that the respective plans for the Interconnection Planning Coordinator Area meet reliability standards. 2. Identify and report on potential transmission system and resource adequacy deficiencies, and provide alternate plans that mitigate these deficiencies. • Monitor transmission expansion plan and resource plan implementation • Coordinate projects requiring transmission outages that can impact reliability and firm transactions • Evaluate the impact of revised transmission and generator in-service dates on resource and transmission adequacy • Work with adjoining Interconnection Planning Coordinators so that system models and resource and transmission expansion plans take into account modifications made to networks in adjacent Interconnection Planning Coordinator Areas

4.7 Market Operator

The Market Operator administers markets to provide capacity, energy, balancing resources and other Ancillary Services subject to system requirements and constraints. This function is not really a function of the Functional Model but is included in it to facilitate describing the interaction with other functions in the model.

Grid West will serve as the Market Operator for the following markets and services:

- Transmission Rights Reconfiguration Service: Wll facilitate the acquisition and trading of transmission rights by Grid West participants. This service will be facilitated for the GWMT.
- Reserves: Will facilitate the day-ahead procurement of reserves necessary to meet the applicable Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC) and the North American Reliability Council (NERC) Operating Policy Standards related to regulation performance and operating reserves and other reliability standards. This market will be facilitated for the CCA but non-CCA members can also offer to provide services.
- Real-Time Balancing Service: Will facilitate the real-time procurement of balancing energy on the basis of economics and reliability in order to match system load with online generation while observing resource and transmission constraints. This service will be facilitated for the CCA but non-CCA members can also offer to provide services.

4.8 Generator Operator

The role and key tasks performed by the Generator Operator as defined in the Functional Model are summarized in the table below.

Generation owning members, whether those that also own transmission facilities or IPPs, will serve as the Generator Operator for their respective facilities with operations coordinated through the control area where the facilities are located.

Table 4.7 Generator Operator Role and Tasks

Function	Generator Operator
Role	Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services including non-market IOS (e.g., reactive power supply, black-start capability).
Key Tasks	• Operate generators to provide energy or Interconnected Operations Services (or both) per contracts or arrangements • Formulate daily generation plan • Report operating and availability status of units and related equipment, such as automatic voltage regulators • Develop annual maintenance plan for generating units and perform the day-to-day generator maintenance

5.0 ROLES AND RESPONSIBILITIES

Roles and responsibilities of Grid West and its members with respect to key reliability, market operations and system operations functions identified by the NERC Reliability Functional Model are summarized in the table below.

Table 5.1 NERC Reliability Functional Model Roles and Responsibilities in Grid West

Function	Grid West	Member: CCA	Member: Non-CCA	IPPs	PNSC
Interconnection Reliability Authority	None				Pacific North West including GWMT
Balancing Authority	CCA		Own Balancing Authority Area		
Interchange Coordinator	CCA (initially)		Own Balancing Authority Area		
Transmission Service Provider	GWMT	(for pre-existing contracts)	(for pre-existing contracts)		

Transmission Authority	GWMT	Operational responsibilities for own facilities as directed by GW or per standing orders	Operational responsibilities for own facilities as directed by GW or per standing orders	Operational responsibilities for own facilities as directed by GW or per standing orders	
Planning Reliability Authority	GWMT				
Market Operator	Reserve Market and RTBS for CCA, RCS for GWMT				
Generator Operator		Own facilities	Own facilities	Own facilities	

6.0 MARKET BENCHMARKS

All RTOs/ISOs in North America perform some of the NERC Reliability Functional Model responsibilities. The table below compares the assignment of these responsibilities in the Grid West with the assignment in PJM, ERCOT and MISO.

Table 6.1 Market Benchmarks

Function	Grid West	PJM	ERCOT	MISO
Interconnection Reliability Authority	PNSC for Pacific Northwest including GWMT	Entire footprint	Entire footprint	Entire footprint
Balancing Authority	CCA	Entire footprint	Entire footprint	Various BAs within footprint
Interchange Coordinator	CCA (initially)	Entire footprint	Not really an IA. Few transactions with external connections.	Not really an IA. NERC scheduling for portions of the entire footprint located within BAs covered by the EMT
Transmission Service Provider	GWMT	Entire footprint	Various TSPs within the footprint	Portions of the entire footprint located within BAs covered by the EMT
Transmission Authority	GWMT with operational	Owners as directed by PJM	Owners as directed and	Owners as directed by

	responsibilities delegated to TOs		coordinated by TSPs and ERCOT	MISO
Interconnection Planning Coordinator	GWMT	Entire footprint	Entire footprint	Entire footprint
Market Operator	Reserve Market and RTBS for CCA, RCS for GWMT	Entire footprint	Entire footprint	Portions of the entire footprint located within BAs covered by the EMT
Generator Operator	Owners as directed by corresponding BAs	Owners as directed by PJM	Owners as directed by QSE	Owners as directed by corresponding BAs

7.0 TECHNOLOGY SOLUTIONS

The NERC Reliability Functional Model responsibilities that the Grid West will perform will require the following applications/systems:

- SCADA including telemetry from RTUs and/or ICCP
- Data acquisition (SCADA) including telemetry from RTUs and/or ICCP
- Real-Time Calculations
- Alarming
- Reserve Computation
- Automatic Generation Control (AGC)
- Outage Scheduling
- Advance Power System Applications; State Estimator, Contingency Analysis, Power Flow, etc.
- Transaction Scheduling System
- OASIS and E-tagging tools
- Transmission Rights Reconfiguration Service tools
- Reserve Markets and Real-Time Balancing Service tools
- Voice communications between Grid West and member entities control centers

8.0 COST DRIVERS

The Grid West functional responsibilities described in this paper encompass a significant portion of the overall operational responsibilities of Grid West. The primary cost drivers for the implementation of these functional responsibilities include infrastructure, personnel and system requirements.

9.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- The exact nature of the relationship between the PNSC and Grid West needs to be defined further, particularly with regard to governance, independence and duplication of effort.

1.0 EXECUTIVE SUMMARY

Grid West will perform several of the roles defined within the NERC Reliability Functional Model for both the Consolidated Control Area (CCA) and for the Grid West Managed Transmission System (GWMT). Examples include:

- Reliability functions
- System operation functions
- Market operations functions

To perform these roles, Grid West must have the ability to monitor, analyze and process relevant system conditions and data in real time. A number of systems and applications will be implemented to provide Grid West with this capability. These will include a real-time data acquisition function to enable the acquisition of real-time measurements, applications to process and/or calculate other relevant quantities (e.g., alarming, real-time calculations, reserve calculation, AGC), applications to analyze system conditions (State Estimator, Contingency Analysis, etc.) and market applications. This paper identifies the relevant system conditions and data for each Grid West functional responsibility, as well as the system and/or application associated with each system condition and data item.[1]

Highlights of this paper include:

- Grid West will monitor a number of system conditions and data as part of its reliability, systems operations and market operations functional responsibilities.
- Grid West will implement a variety of systems and applications to provide the required real-time monitoring functionality. These will include:
    a. Supervisory Control and Data Acquisition (SCADA)
    b. Generation and scheduling functions: Automatic Generation Control (AGC), Reserve Monitoring, Load Forecasting, Interchange Scheduling, Energy Accounting
    c. Advanced power system applications: Outage Scheduling, Network Status Processor, State Estimator, Contingency Analysis, Post-Disturbance Recording
    d. Market functions: OASIS, Tag applications, Market Portal, Real-time Balancing Service

[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 the detailed design phase of this effort.

e. Communications Functions: Inter Control Center Communications Protocol (ICCP) for real-time data exchange and Electric Industry Data Exchange (EIDE) for non real-time data exchange.

- Grid West will acquire real-time measurements from member control centers and external control centers via ICCP and will acquire non real-time data (such as meter data, schedule data, lake elevations, etc.) via EIDE. Redundancy for critical measurements will also have to be considered.

2.0 PURPOSE

This paper identifies the relevant system conditions and data that Grid West will monitor, process and analyze in real time in support of its reliability, system operations and market operations functions. The paper also identifies systems and applications associated with each system condition and data item.

3.0 BACKGROUND

3.1 Grid West Reliability and Market Functions

Grid West's functional responsibilities for reliability, system operations and market operations of the CCA and for the GWMT are summarized in the table below. Performance of some of these functions requires real-time monitoring capabilities that are described in the sections that follow.

Figure 3.1 Grid West responsibilities for the CCA and the GWMT

Function	CCA	GWMT
Transmission Authority		☑
Balancing Authority	☑	
Interchange Coordinator	☑	
Transmission Service Provider		☑
Interconnection Planning Coordinator		☑
Market Operator	☑	

4.0 GRID WEST'S REAL-TIME MONITORING REQUIREMENTS

4.1 Transmission Authority Function

As the Transmission Authority for the GWMT, Grid West will ensure the real-time operating reliability of the bulk electric transmission systems of the GWMT. The table below summarizes the key system conditions and data items that need to be monitored as part of this function. The system and/or applications associated with each item are also identified.

Table 4.1 Transmission Authority Function Monitoring Conditions

System Condition/Data Item	System/Application
Thermal facilities – transmission paths, transmission lines, transformers, Phase Angle Regulators (PARs), actual flows and post-contingency flows	• SCADA • State Estimator • Contingency Analysis
Voltage – actual and post-contingency	• SCADA • State Estimator • Contingency Analysis
Generation facilities – status, active and reactive outputs, max and min response capabilities	• SCADA • AGC
Active and reactive reserves – requirements, actual amount and location	• SCADA • Reserve Calculation
ACE, system frequency, total system load and generation, actual interchange, scheduled interchange, short-term load forecast	• SCADA • Real-Time Calculations • AGC • Interchange Scheduling • Load Forecaster
Neighboring systems: major facilities, ACE, reserves	• SCADA • Real-Time Calculations
Status/outage of generator and transmission facilities, notification of modifications to network topology and ICCP data points	• SCADA • Network Status Processor • Outage Scheduling
Status of RAS and system conditions requiring RAS operations	• SCADA • RAS Application
System disturbances	• SCADA
Communication Systems	• SCADA • HW/SW Monitoring tools

4.2 Balancing Authority Function

As the Balancing Authority for the CCA, Grid West will integrate resource plans ahead of time, keep actual interchange equal to its scheduled interchange and provide frequency bias obligation for the CCA in real time.

The table below summarizes the key system conditions and data items needed as part of this function. The monitoring processes associated with each item are also identified.

Table 4.2 Balancing Authority Function Monitoring Conditions

System Condition/Data Item	System/Application
ACE, system load, total generation and total interchange	• SCADA • Real-Time Calculations • AGC
Transmission facilities: control area interchange points (tie-lines) flows	• SCADA • AGC
Short-term load forecast	• Load Forecaster
Net scheduled interchange amount including anticipated changes and ramps	• SCADA • Reserve Calculation
Generation facilities – status, MW outputs, limits, response capability, regulation reserve awards/designations	• SCADA • AGC • Reserve Calculation
Reserves: actual reserves; regulation, spin and non-spin	• SCADA • Reserve Calculation
Energy Accounting, Actual Interchange calculation, Inadvertent Interchange and time error	• AGC

4.3 Interchange Coordinator Function

As the Interchange Authority for the CCA, Grid West will receive approvals and communicate authorization to implement valid and balanced interchange schedules, and will ensure interchange transactions are properly identified for reliability assessment purposes. The table below summarizes the key system conditions and data items needed as part of this function. The monitoring processes associated with each item are also identified.

Table 4.3 Interchange Coordinator Function Monitoring Conditions

System Condition/Data Item	System/Application
Interchange transactions: start and end times, ramps, amounts, point of delivery/point of receipt, transmission rights, etc	• Interchange Scheduling • OASIS
E-tag information: transaction data, approvals, denials, etc.	• Tag Applications
Ramping capability of source/sink control areas	• SCADA • Real-Time Calculations • AGC
Net scheduled interchange amount including anticipated changes and ramps	• Interchange Scheduling • OASIS

4.4 Transmission Service Provider

As the Transmission Service Provider for the GWMT, Grid West will administer the transmission tariff and provide transmission services to qualified market participants, and will direct the operations of the transmission facilities. The table below summarizes the key system conditions and data items needed as part of these functions. The monitoring processes associated with each item are also identified.

Table 4.4 Transmission Service Provider Function Monitoring Conditions

System Condition/Data Item	System/Application
Transmission Service Requests	• OASIS
AFC	• AFC Calculation
Thermal facilities – transmission paths, transmission lines, transformers, PARs, actual flows and post-contingency flows	• SCADA • State Estimator • Contingency Analysis
Voltage – actual and post-contingency	• SCADA • State Estimator • Contingency Analysis
Status/outage/maintenance plans of transmission facilities	• SCADA • Network Status Processor • Outage Scheduling
Interchange transactions: start and end times, ramps, amounts, point of delivery/point of receipt, transmission rights, etc	• Interchange Scheduling • OASIS

4.5 Market Operator Function

As the Market Operator, Grid West will administer a Reserve Market and a Real-time Balancing Service for the CCA. The table below summarizes the key system conditions and data items needed as part of these functions. The monitoring processes associated with each item are also identified.

Table 4.5 Market Operator Function Monitoring Conditions

System Condition/Data Item	System/Application
Generation facilities – status, MW outputs, limits, response capability, regulation reserve awards/designations	• SCADA • AGC • Reserve Calculation

Reserves: actual reserves; regulation, spin and non-spin	• SCADA • Reserve Calculation
Reserve Requirements	• Reserve Calculation
Reserve Offers, Inc/Dec Bids	• Market Portal
Balanced Schedules	• Market Portal
Load Forecast	• Load Forecaster
System solution, constraints	• SCADA • State Estimator • Contingency Analysis
Status/outage/maintenance plans of transmission facilities	• SCADA • Network Status Processor • Outage Scheduling

4.6 Real-Time Measurements

A critical component of Grid West's real-time monitoring requirements is the acquisition of real-time measurements. It is anticipated that Grid West will obtain real-time measurements from existing member control centers and external control centers via data exchange mechanisms (e.g., ICCP). This will eliminate the need to implement dedicated remote terminal units (RTUs) and the associated communications infrastructure and will help minimize implementation costs. However, the implementation of redundancy for all measurements critical to the Reliability Authority and Balancing Authority (e.g., generator MW outputs, tie-line flows, transmission path flows, critical system voltages) will have to be considered. In many cases, existing control areas have implemented redundancy throughout their systems. Using redundant ICCP links, routers and multiple WECC Operational Network (WON) physical paths would provide redundancy in these cases

5.0 ROLES AND RESPONSIBILITIES

Grid West will implement, operate and maintain all systems and applications described in this paper.

Transmission owning members will provide real-time measurements to Grid West via data exchange mechanisms. This will include all data currently available at the existing control centers.

Transmission owning members will support the creation and maintenance of a network model representation of their facilities to be incorporated in the model

used by Grid West. This model together with the available measurement set will be key to the operation of the State Estimator and Contingency Analysis functions.

6.0 MARKET BENCHMARKS

All existing RTOs/ISOs have implemented and are operating systems and applications as the ones described here. There will probably be functional differences between some of the RTOs/ISOs and Grid West, but these will be mostly due to differences is market design and operational practices.

7.0 TECHNOLOGY SOLUTIONS

A number of systems and applications will be required to support the Grid West real-time monitoring requirements. These are briefly described below in terms of the monitoring function that they provide:

- Supervisory Control and Data Acquisition (SCADA): Enables acquisition of all required real-time measurements (e.g., line flows, voltages, breaker/switch statuses). Data will be acquired from either remote terminal units (RTUs) or from other control centers via data exchange mechanisms (e.g., ICCP). Also processes all incoming real-time measurements and calculated quantities to identify those exceeding pre-defined limits (analog quantities) or in an abnormal state (digital statuses). Alarms for each of the identified items are generated to allow system operators to quickly identify issues.

- Real-Time Calculations (typically part of SCADA): Enables calculations of other quantities of interest based on incoming real-time measurements. These are simple calculations such as additions, subtraction, AND., O.R., etc.

- Reserve Monitoring: Calculates actual reserves based on current generator conditions (statuses, actual outputs, etc.), operating characteristics (limits, response rates, etc.) and reserve awards/designations.

- Automatic Generation Control (AGC): Calculates ACE and over/under generation conditions. Will also calculate total system load and generations and actual interchange.

- Energy Accounting: Necessary to calculate Inadvertent Interchange which is an ACE component. Calculates Actual Interchange and Inadvertent Interchange and cumulative Inadvertent for light and heavy load hours

- Interchange Scheduling: Keeps track of interchange transactions. Calculates net scheduled interchange including anticipated changes and ramps.

- Outage Scheduling: Keeps track of planned and forced outages.

- Network Status Processor: Calculates equipment connectivity statuses.

- State Estimator: Uses a network model representation of the system together with available measurements (breaker/switch statuses and analog measurements) to develop a complete system solution that can be used by other power system analysis applications. Also performs bad data detection to identify measurements in error.

- Contingency Analysis: Uses the current State Estimator solution to analyze the impact of single and multiple contingencies in real-time. Provides post-contingency flows and voltages for monitored thermal facilities and buses.

- Tag applications: Facilitates creation and processing of e-tags. Processes tag approvals and rejections.

- OASIS (transmission service information system): Use to post available transmission rights and process transmission service requests.

- AFC Calculation: Calculates AFC based on approved rights.

- Communications: ICCP used for real-time data exchange over the WON. EIDE used for non real-time data exchange over either the WON or the Internet.

8.0 COST DRIVERS

The primary cost drivers for the implementation of the real-time monitoring requirements described in this paper are infrastructure, personnel and systems and applications requirements.

Other implementation-related cost drivers include:

- Redundancy of critical real-time measurements
- Network model development

9.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Redundancy of real-time measurements* - Redundancy for all measurements critical to the Reliability Authority and Balancing Authority (e.g., generator MW outputs, tie-line flows, transmission path flows, critical system voltages) should be implemented.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

This paper describes the Grid West Real-Time[1] Balancing Service (RBS) that will be used to acquire Interconnected Operations Services[2] (IOS) to provide balancing service for the Consolidated Control Area (CCA), while accounting for the nature and types of bids and offers, and selection of resources. It also describes the dispatch process for resources selected by Grid West for the balancing service, including dispatch granularity, dispatch frequency, control signals process and routing, etc.[3]

Highlights of this paper include:

- Grid West will administer the RBS for the CCA
- Transmission Customers are required to submit balanced energy schedules before entering real-time operations
- Imbalance requirements are expected to be a small percentage of the total energy demand
- Parties within the CCA may submit INC offers and/or DEC bids into the RBS
- Parties <u>outside</u> the CCA can also submit INC offers and/or DEC bids to provide services. These will be considered as long as they serve to meet the requirements of the CCA.
- Grid West will not require participants to obtain transmission rights to participate in the RBS
- Balancing service will support generation/load following, manage congestion, and promote economic efficiency within the CCA
- Locational pricing will be used; however, the consolidating parties will determine how suppliers and loads will be charged (e.g., locational imbalance price might be used to pay generators while zonal prices may be used to charge loads)
- Dispatch instructions, in the form of generation basepoints and dynamic schedules, will be routed through the Grid West control system to the

[1] Real-Time is defined as the time period between 30 minutes prior to the Operating Hour to the close of the hour.
[2] IOS are used to maintain generation and demand balance (i.e., regulation, load following and contingency reserve), to maintain a secure transmission network (i.e., reactive power supply and frequency response) and for emergency preparedness and restoration (i.e., black-start capability). The purpose of RBS is to maintain generation and demand balance.
[3] 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.

control systems of consolidating Transmission Owners (TOs) and participants outside the CCA

2.0 PURPOSE

The purpose of the RBS is to reliably match system supply and demand of the Grid West CCA. It will utilize available bids and offers to provide imbalance requirements economically while observing all system operating constraints. A secondary consideration of the RBS is enhancing economic efficiency through a full utilization of the transmission capability of the Grid West Managed Transmission System—which addresses one of the fundamental problems identified in the RRG Regional Proposal.

3.0 BACKGROUND

A majority of the CCA energy requirements are met through accepted balanced schedules. However, energy imbalances, i.e., differences between supply and demand - are inevitable during real-time operations. Imbalance energy can result from any of the following:

- Intra-hour load variations including load forecast errors and loss variations (Load Following)
- Generation deviation
- Transmission congestion
- Forced generation or transmission outages

Uncorrected, these deviations threaten the reliability of the system and must therefore be offset to maintain system/frequency balance. Currently, control areas apply financial consequences to transmission users that are responsible for schedule imbalances. Each Transmission Service Provider in the Pacific Northwest administers its own imbalance process as a part of its Open Access Transmission Tariff (OATT). As a result, Transmission Customers that do business across Transmission Service Providers are exposed to disparate imbalance charges. For example, some Transmission Service Providers charge a fixed rate while others use an indexed price. These administrative solutions do not reflect the true cost of imbalance.

As a part of the Regional Proposal, it is envisioned that three or more control areas will voluntarily consolidate their control area operations under Grid West. As a part of this consolidation, it is envisioned that Grid West will administer the RBS on behalf of the consolidating parties. Parties that do not consolidate will continue to implement their respective imbalance procedures. Consequently, Transmission Customers that do business with Grid West Transmission Service

Providers who are not part of CCA will continue to be charged for imbalance per the terms of the non-consolidating TSPs tariff. Imbalance for pre-existing transmission services will continue to be governed by the terms of the tariff or contract under which such service is provided. The Grid West RBS will provide an optimal, bid-based balancing service for the benefit of the CCA, while maintaining security constraints. While this is the primary objective of the service, additional benefits could include:

- Establishing equitable treatment of imbalances
- Promoting increased usage of available transmission in real-time
- Providing improved price signals for the forward markets
- Motivating and informing investment in generation and transmission

4.0 REAL-TIME BALANCING SERVICE

4.1 Overview

Energy imbalance is a part of normal operations. It occurs in control areas continuously. Currently the region does not have a consistent approach to dealing with imbalances. As a result of consolidation, the Grid West CCA will provide a Real-Time Balancing Service to all Transmission Customers in the CCA. Balancing service will be provided for the CCA in order to address/facilitate:

- Offsetting deviations from schedules
- Load/Generation Following
- Congestion Management (Redispatch for Reliability)
- Economic Dispatch (Re-dispatch for Economics)

The goal of the RBS is to match generation with load in a least cost manner, while respecting security constraints. Since participants are required to submit balanced schedules, the imbalance requirement should be relatively small. In other markets with balanced schedule requirements, like ERCOT and CAISO, imbalance energy makes up less than 5% of total energy demand. This percentage is also observed in markets that do not require balanced schedules, but have a DA market that generates balanced schedules.

4.2 Balanced Schedules

As a part of the day-ahead scheduling process, participants are required to submit hourly balanced schedules based upon their submitted load forecasts. For example, if Participant A has a load forecast of 100 MW, it must submit a balanced schedule, identifying the resources that will be used to meet its load plus allocated losses. By definition, imbalance does not exist at this point (resource MW = load MW + allocated losses). However, during real-time operations, conditions arise (e.g., actual load differing from forecasted load, loss of generation, etc.) where participants deviate from their schedules, resulting in imbalances. In these instances, Grid West will need to provide imbalance service on behalf of participants within the CCA.

Energy imbalance will be calculated, by participant, as the difference between actual metered values, and either final schedules (this paper will assume a scheduling deadline at 30 minutes prior to the operating hour), or schedules as determined by the RBS or as otherwise changed by Grid West. Energy imbalance charges will be based on the locational imbalance price, as determined by the RBS.

4.3 Supply of Imbalance Energy

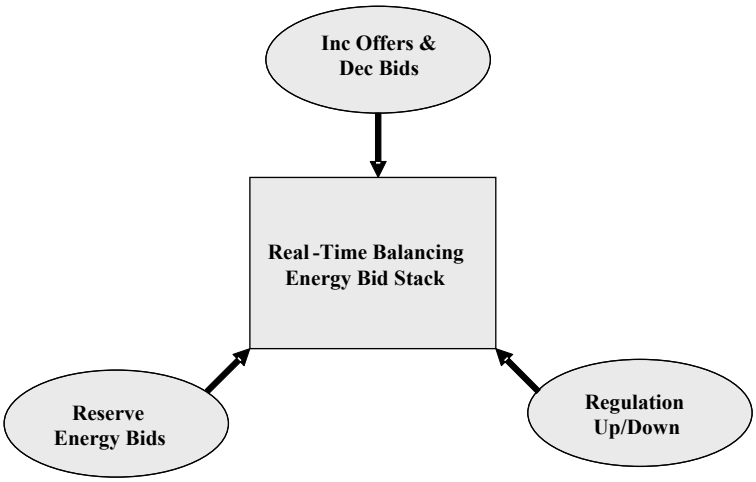
Resource participation in the RBS is voluntary. Participants can bid into the market to give Grid West options it can use to provide the imbalance service. Grid West will meet its balancing needs by procuring balancing service from the following sources:

- **Inc Offers & Dec Bids.** Participants can submit energy offers and/or bids for real-time energy up until 30 minutes before each operating hour. An INC offer indicates a willingness to increase generation at a specific injection point by a given amount for a given price. In under-generation situations, these offers are primarily used to obtain the lowest cost energy available to the CCA. A DEC bid indicates a willingness to reduce generation at a point of injection by a given amount for a given price. This is equivalent to a bid to buy energy from Grid West for a given price in lieu of generating as originally scheduled. In over-generation situations, these offers are used primarily to get the highest price for energy that is surplus to CCA needs. Dispatchable loads that submit INC offers or DEC bids, indicating their willingness to decrease or increase their load by a given amount for a given price, have an effect that is equivalent to increased generation or decreased generation.

- **Ancillary Services Energy Bids**: Participants whose capacity offers have been selected as a part of the reserve market may also submit a separate offer for energy in case they are called upon in real-time. These resources may make their energy bid conditional.

- **Regulation:** Regulating Reserve is used in conjunction with automatic generation control (AGC) to offset random fluctuations in system balance.

Figure 4.1 RBS Bids and Offers Stack



Participants submitting INC offers and/or DEC bids have the ability to flag their submissions as "Reliability Only". These bids will not be used for economic transactions. Instead they will only be used to resolve imbalance or manage transmission congestion. Participants outside the CCA can also submit bids and offers to provide services. These bids and offers will only be selected if they help meet the requirements of the CCA (i.e., energy imbalance, congestion and economics of the CCA).

Bids and Offers will be in the form of price-quantity pairs describing a curve of up to ten segments, and may be changed for each interval For example, for a generator with a curve with 4 segments, the price quantity pairs for two intervals may look as follows:

Table 4.1 Bids/Offers Price Quantity Pairs

Hour	Segment	MW	Price
0100	1	10	5
0100	2	20	10
0100	3	30	20
0100	4	40	50
0200	1	10	7
0200	2	20	11
0200	3	30	21
0200	4	40	60

Participants can adjust their bids and/or offers up to 30 minutes prior to the Operating Hour.

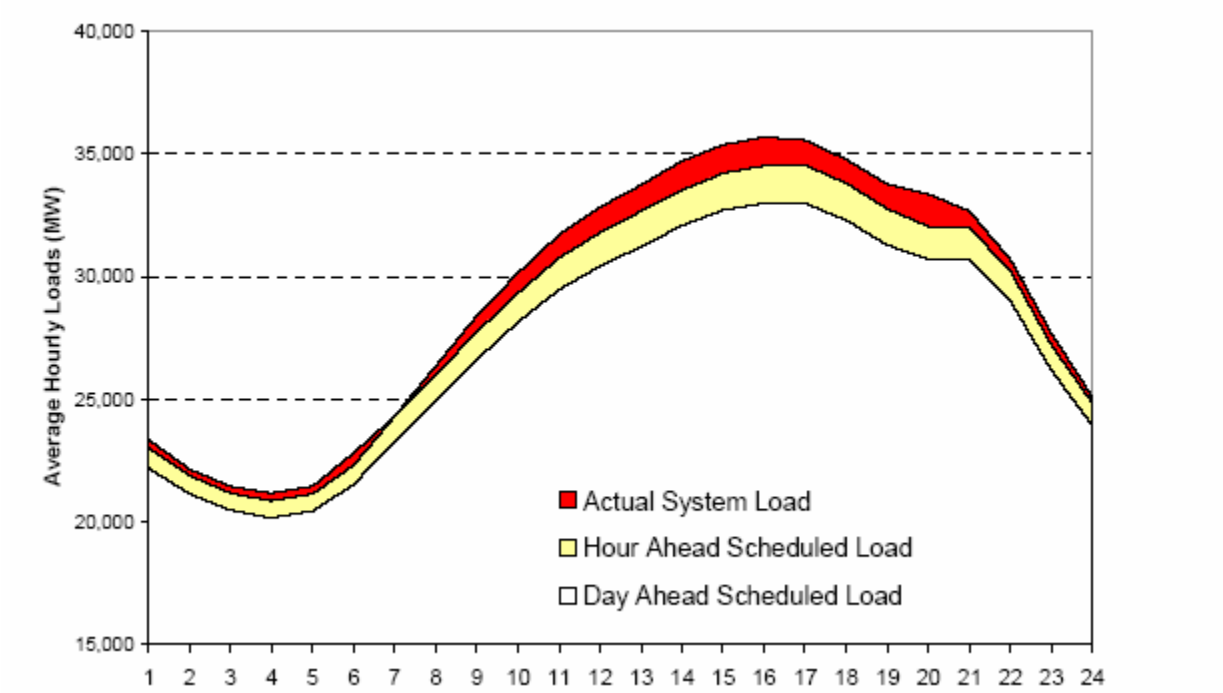
4.4 Imbalance Requirement

Grid West is only concerned with imbalance within the CCA. Control Areas outside the CCA will deal with imbalance as they choose.

Other RTOs/ISOs attempt to minimize the amount of imbalance energy that is required in real-time by ensuring that there is enough scheduled generation to meet forecasted load. This is accomplished by either imposing a balanced schedule requirement or running centralized day-ahead energy market. Since Grid West does not have a DA market, it will impose a balanced schedule requirement similar to CAISO and ERCOT.

The balanced hourly schedule requirement does not address imbalances in real-time. Hourly schedules are by their nature fixed, while load is dynamic through time, often changing dramatically through a given hour, and requiring large generation changes generally referred to as load following. To accommodate some degree of self-provision for load following, Grid West will allow participant to submit “ramped” schedules. These will specify ramp rates, generation ranges, and time intervals such that Grid West will be able to predict the generation changes expected in the CCA. To account for the remaining deviations, Grid West will perform a short-term load forecast to determine the demand for the balancing period. Grid West will compare this forecast with the current real-time system conditions and scheduled generation changes in order to calculate the balancing requirement for the next interval. Given that Grid West is only providing balancing service to meet these deviations (provided that all generation performs as scheduled) balancing energy will be small relative to the total wholesale generation produced for a given dispatch interval.

Figure 4.2 Actual Loads vs. Hourly Load Schedules



Source: CAISO Report

4.5 Security Constrained Economic Dispatch (SCED)

Grid West stacks the bids and offers submitted by participants in merit order (lowest to highest for the INCs and highest to lowest for the DECs). Specific rules associated with the stacking of non-spinning, spinning, and regulation reserve conditional energy offers still need to be developed. Grid West then operates a Security Constrained Economic Dispatch (SCED) to bring the CCA into balance. The objective function of SCED is to select bids and offers that maximize Real-Time Balancing Service value for the CCA.

The inputs into the model are:

- Short-term Load Forecast
- Current System Conditions (from State Estimator)
- Constraints (Transmission and Generation)
- INC offers & DEC bids
- Resource Schedules (Operating Plan and Constraints)

The SCED algorithm will resolve any CCA imbalance while maintaining system security. In addition, it will also re-dispatch all resources whose bids can improve economic efficiency. This is similar to real-time balancing markets used by other RTOs/ISOs. The result is a least-cost dispatch solution consisting of locational imbalance prices, generation basepoints, and adjusted Net Scheduled Interchanges (NSIs). The locational prices can vary from one interval to the next. The prices reflect the value of imbalance energy for a specific period of time and location. The solution is "security constrained" in that it takes into consideration security limits and contingencies.

The execution frequency for the SCED process has been deferred to future design phases.

5.0 DISPATCH INSTRUCTIONS

After the balancing service required for a time interval is determined, Grid West must communicate its results (dispatch instructions) to the participants. This is referred to as central dispatch. Under normal operating conditions, only resources (generation and load) that participate in the RBS (those who submitted bids and offers) will receive dispatch instructions. Resources that do not participate in this service will be considered "non-dispatchable" for balancing purposes.

Dispatch instructions will be in the form of generation basepoints. Basepoints are total specific MW values (i.e. 100 MW) for generation output - as opposed to incremental amounts (i.e., up 10 MW, down 20 MW). Basepoints will be sent to the generators through the consolidating transmission owners control centers five minutes prior to the real-time operating period (T-5). Control centers will either ramp the units or pass the Basepoints to the Generator Operators, so that they achieve the target MW output at time T. Grid West will not directly control generating units. The respective control centers and Generator Operators will be responsible for implementing these instructions. This approach is similar to some of the existing RTOs and ISOs where the control centers of the participating utilities are maintained. It, also eliminates concern regarding the operation of Federal resources by non-federal entities. Finally, this approach leverages existing infrastructure and minimizes incremental costs. Where there are multiple generators at a single node, they may be offered as a single unit and will be dispatched as described above.

For RBS participants not within the CCA, the incremental (or decremental) energy that results from this dispatch will be implemented as a dynamic schedule.

6.0 ROLES AND RESPONSIBILITIES

The roles and responsibilities of Grid West and participants within and outside the CCA are described in the table below.

Table 6.1 RBS Roles and Responsibilities

Time	Grid West	Participant within the CCA	Participant Outside the CCA
OH-30		• Submit Final Schedules • Submit INC offers or DEC bids (voluntary unless there are insufficient bids and offers to meet needs)	• Submit INC offers or DEC bids (voluntary)
T-5	• Calculate Load Forecast • Perform SCED • Send NSI signals • Issue Dispatch Instructions		
T	• Monitor ACE for CCA	• Ramp units	• Ramp units
T + 5	• Monitor performance	•	•
T + 60	• Post Results	• Download Results	• Download Results

7.0 MARKET BENCHMARKS

All RTOs/ISOs have a functioning real-time balancing/energy market. In addition, several have day-ahead energy markets in order to balance their schedules before entering into real-time operation. The proposed balancing service is closest to the real-time energy market used by ERCOT. The primary difference is that ERCOT currently uses a less granular pricing model (zonal) for both generation and load.

Table 7.1 Market Benchmarks

Attribute	PJM	ERCOT	MISO
Zonal/Nodal	• Nodal	• Zonal	• Nodal
Bidding Mechanism	• Offer Curve	• Inc/Dec	• Offer Curve
Bidding Granularity	• Daily	• 15 min	• Hourly

Pricing	• LMP	• LMP (zonal)	• LMP
Dispatch Granularity	• Unit Specific	• Portfolio	• Unit Specific
Dispatch Frequency	• 5 min	• 15 min	• 5 min

8.0 TECHNOLOGY SOLUTIONS

The Real-Time Balancing Service requires the following applications/systems:

- Scheduling/Bidding Application
- Real-Time Monitoring Tools (State Estimator, Power Flow)
- Load Forecasting Application
- Balancing Market and Dispatch Function (SCED, etc.)
- Existing CCA participant infrastructure

9.0 COST DRIVERS

The primary cost drivers associated with the Real-Time Balancing Service & Dispatch include:

- Bidding granularity
- Number of locations
- Market clearing frequency
- Dispatch granularity

10.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The following design issues are open for further consideration:

- *Dispatch Frequency* – What should the dispatch periodicity? 5, 10, 15 minutes?

- *Intra-hour generation ramps* – To accommodate some degree of self-provision for large generation ramps, it is expected that Grid West will allow participant to submit “ramped” schedules. These will specify ramp rates, generation ranges, and time intervals such that Grid West will be able to predict the generation changes expected in the CCA. (See Section 4.4)

- *Limited must-offer*: The real-time balancing market is voluntary. However, since Grid West does not own any resources it must have an adequate supply of bids to maintain reliable operations. Since the real-time balancing service has been created for the benefit of the CCA, should consolidating parties have an obligation to make offers to the balancing service if sufficient offers have not been submitted by a given time? The current consensus in the TSLG is to have Grid West make an adequacy assessment when running the day-ahead reserve market, allowing it to invoke the limited must-offer obligation on an as needed basis.

.

- *Load Frequency Response* – How is regulation taken into consideration in the Bid Stack? How will Grid West deploy it? Should this be included in the A/S deployment paper?

- *Bid Cap* – Since demand is generally not price-sensitive, scarcity conditions can generate high prices. Grid West will have to determine the appropriate bid cap, in any, to set.

- *Congestion Outside CCA* – How will congestion be managed outside of the CCA?

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

As the Transmission Authority for the Grid West Managed Transmission System (GWMT), Grid West will be responsible for developing and implementing emergency procedures. Grid West will monitor relevant system conditions, will identify and declare emergency conditions as necessary, and will work with Transmission Owners, Balancing Authorities, Load-serving Entities and Generation Owners within the GWMT to implement emergency procedures. Grid West will also work with the Pacific Northwest Security Coordinator (PNSC) and the Northwest Power Pool (NWPP) on the implementation of the NWPP Energy Emergency Plan and to coordinate receiving and/or providing assistance during emergency conditions.[1]

Highlights of this paper include:

- Grid West will be responsible for the development and implementation of emergency procedures for the GWMT.
- Grid West's emergency operations responsibilities are defined within the framework of the responsibilities identified in NERC Reliability Standards.

2.0 PURPOSE

This paper describes the emergency operations responsibilities that Grid West will perform for the GWMT. The paper uses NERC Reliability Standards as a framework for identifying the relevant emergency operations responsibilities.

3.0 BACKGROUND

3.1 Emergency Conditions

For the purposes of this paper, an emergency system condition is described as follows:

- An abnormal system condition that requires manual or automatic action to prevent or limit loss of transmission facilities, generation resources, or load; and that impacts or could adversely affect the reliability of the electric system.

[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.

- A condition where an LSE is, or expects to be, unable to provide its customer's energy requirements, and has been unsuccessful in locating other systems from which to purchase, or cannot schedule resources due to system limitations, e.g., AFC or transmission loading relief.

3.2 Operating Limits

Operating limits used for the identifying and declaring of emergency conditions are defined as follows:

- System Operating Limit (SOL). The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to
    - Facility Ratings
    - Transient Stability Ratings
    - Voltage Stability Ratings
    - System Voltage Limits

- Interconnection Reliability Operating Limit (IROL). The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

3.3 NERC Reliability Standards

NERC Reliability Standards describe the responsibilities of an Operating Authority during emergency operations. The policy describes an Operating Authority as an entity that:

- Has ultimate accountability for a defined portion of the bulk electric system to meet one or more of three reliability objectives – generation/demand balance, transmission reliability, and/or emergency preparedness, and

- Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

- Has the authority to control or direct the operation of generating resources, transmission facilities, or loads to meet these policies.

As the Transmission Authority for the GWMT, Grid West will perform these responsibilities for the GWMT. Therefore, Grid West is the Operating Authority for the GWMT within the context of this policy.

3.4 NWPP Energy Emergency Plan

The NWPP Energy Emergency Plan has been put in place by control areas in the NWPP area to increase the area's ability to avoid a power emergency or longer-term adequacy problem by promoting area coordination and communications. The plan is aimed at promoting actions in advance to avoid potential short-term emergencies and longer-term energy adequacy problems in the NWPP area. These actions are targeted to alleviate the need for the Interconnection Reliability Coordinator to declare a NERC Energy Emergency Alert 1, 2 or 3 as defined in NERC Policy 9, Appendix 9B. The plan isdesigned to be invoked when the area has a high degree of confidence that a future short-term power emergency or a long-term energy adequacy problem would adversely affect reliability within the NWPP.

4.0 GRID WEST'S EMERGENCY OPERATIONS RESPONSIBILITIES

Grid West will serve as the Transmission Authority for the entire GWMT. Transmission Owners and Generation Owners will have operational responsibilities for their facilities as directed by Grid West or per standing order.

As the Transmission Authority for the GWMT, Grid West will have the responsibility and authority to direct and coordinate the operation of transmission facilities within the GWMT to maintain the reliability of the bulk electric system. A key component of these responsibilities is to develop and implement emergency procedures.

The table below summarizes Grid West's emergency operations responsibilities within the framework of the responsibilities identified in NERC Reliability Standards (see Section 3.3).

Table 4.1 Emergency Operations Responsibilities

Responsibility	Description	Grid West's Responsibility
Operating within limits	The Operating Authority shall operate within system operating limits (SOLs) and interconnection	GW will perform for the GWMT.

	reliability operating limits (IROLs).	
Operating Authority and responsibility	The Operating Authority shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its Operating Authority Area and shall exercise specific authority to alleviate operating emergencies. The Operating Authority shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load) The Operating Authority shall comply with the Interconnection Reliability Coordinator directives unless such actions would violate safety, equipment or regulatory or statutory requirements. Under these circumstances the Operating Authority must immediately inform the Interconnection Reliability Coordinator of the inability to perform the directive so that it can implement alternate remedial actions.	GW will perform for the GWMT.
Unknown operating states	If the Operating Authority enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be an	GW will perform for the GWMT.

	emergency and shall restore operations to respectable, proven reliable power system limits within 30 minutes.	
Information sharing	To facilitate emergency assistance, the Operating Authority shall inform other potentially affected Operating Authorities and its Interconnection Reliability Coordinator of real-time or anticipated emergency conditions, and take actions to avoid when possible, or mitigate the emergency.	GW will perform for the GWMT.
Rendering assistance	The Operating Authority shall render all available emergency assistance requested, provided that the requesting Operating Authority has implemented its comparable emergency procedures, unless such actions would violate safety, equipment or regulatory or statutory requirements	GW will perform for the GWMT.
Keeping facilities in service	The Operating Authority shall not remove bulk electric system facilities from service if removing those facilities would burden neighboring Operating Authorities unless: The Operating Authority first notifies the adjacent Operating Authorities and coordinates the impact resulting from the removal of the bulk electric system facility or, When time does not permit such notification and coordination, or when immediate action is required	GW will perform for the GWMT.

	to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Operating Authority shall notify adjacent Operating Authorities at the earliest possible time to ensure Operating Authority coordination.	
Remaining interconnected	The Operating Authority shall make every effort to remain connected to the INTERCONNECTION. If the Operating Authority determines that by remaining interconnected, it is in imminent danger of violating System Operating Limits or Interconnected Reliability Operating Limits, the Operating Authority may take such actions as it deems necessary to protect its Operating Authority Area.	GW will perform for the GWMT.
Complying with control performance standards	The Operating Authority shall comply with Control Performance Standards and the Disturbance Control during an emergency.	GW will perform for the CCA.
Coordinating interchange	The Operating Authority shall coordinate interchange schedule changes in accordance with NERC Reliability Standards.	GW will perform for the CCA.
Keeping automatic generation control in service	Each control area shall maintain automatic generation control equipment operational and in service.	GW will perform for the CCA.
Taking immediate action	The Operating Authority shall immediately take action to restore the real and reactive power balance. If the Operating Authority is unable to restore its real and	GW will perform for the GWMT.

	reactive power balance, it shall request emergency assistance. If corrective actions or emergency assistance are not adequate to mitigate the real and reactive power balance, then the Operating Authority shall implement firm load shedding.	
Reducing the effects of power flows	The Operating Authority shall immediately reduce the effects of power flows through other Operating Authority Areas if those flows have been identified as contributing to an operating emergency (e.g., resulting in SOL or IROL violations) in those other Operating Authority Areas.	GW will perform for the GWMT.

Grid West will also work with the PNSC, NWPP and other entities in the Pacific Northwest on the implementation of the NWPP Energy Emergency Plan.

5.0 ROLES AND RESPONSIBILITIES

Grid West will be responsible to develop and implement emergency procedures for the GWMT. Transmission Owners (consolidating or not), LSEs and Generator Owners within the GWMT will be responsible to implement actions requested by Grid West during emergency conditions.

6.0 MARKET BENCHMARKS

All existing RTOs/ISOs in North America are responsible for developing and implementing emergency procedures for their operating authority areas.

7.0 TECHNOLOGY SOLUTIONS

The emergency operations responsibilities that Grid West will perform will require the following applications/systems:

- Data acquisition (SCADA) including telemetry from RTUs and/or ICCP

- Real-Time Calculations
- Alarming
- Reserve Computation
- Automatic Generation Control (AGC)
- Outage Scheduling
- Advance Power System Applications; State Estimator, Contingency Analysis, Power Flow, etc.
- Voice communications between Grid West and member entities' control centers

8.0 ORGANIZATION REQUIREMENTS

The following roles have been identified to support the emergency operations responsibilities that Grid West will perform:

Table 8.1 Organization Requirements

Division	Department	Role
Grid Operations	Real-Time Operations	Shift Supervisor
Grid Operations	Real-Time Operations	Grid Resource Coordinator
Grid Operations	Real-Time Operations	Generation Dispatchers
Grid Operations	Real-Time Operations	Real-Time Schedulers
Grid Operations	Real-Time Operations	Transmission Dispatchers
Grid Operations	Scheduling	Scheduling Manager
Grid Operations	Scheduling	Scheduling Coordinator
Grid Operations	Operations Planning	Manager
Grid Operations	Operations Planning	Outage Coordinator
Grid Operations	Operations Planning	Reliability Assessment
Grid Operations	Operations Planning	Operations Engineer
IT Operations	Application Support	EMS Manager
IT Operations	Application Support	EMS Analyst

9.0 COST DRIVERS

The primary cost drivers for the implementation of these Grid West's emergency operations responsibilities include infrastructure, personnel and system requirements. The system and personnel requirements are summarized in the previous two sections.

10.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

None

(This page intentionally blank)

ANCILLARY SERVICES – MODULE 3b

CCA Reserve Market – Describes the proposed operation of the reserve market used by Grid West to cost-effectively obtain contingency and regulating reserves for the CCA. The topics covered include the reserve products, reserve requirements, market timing, market operation, etc.

CCA Reserve Deployment – Describes the procedures to be used in real-time to deploy the reserves of the CCA that were obtained through the Reserve Market.

CCA Participation in Reserve Sharing – Describes the current Northwest Power Pool reserve sharing agreement and discusses the impact of the Pro Rata Reserve Sharing program on the operation of the CCA.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

As envisioned in the Regional Proposal, Grid West will administer a central reserve market for the Consolidated Control Area (CCA). The CCA reserve market will provide an efficient, cost-effective means to meet the reserve requirements of the CCA. As the CCA reserve market administrator, Grid West will determine the reserve requirements for the CCA system, calculate the obligations of its Transmission Customers, accept and validate Interconnected Operations Services (IOS)[1] offers from the service providers, determine the winning offers and prices, and perform settlement. Grid West will participate as a member of Northwest Power Pool (NWPP) Reserve Sharing Group and provide emergency help to pool members as required.[2]

Highlights of this paper include:

- Grid West will administer a central day-ahead reserve market to procure regulating, spinning and non-spinning reserves
- The purpose of the reserve market is to meet the reserve requirements of the CCA
- Reserves can be provided by eligible resources inside or outside the CCA.
- Reserve requirements are determined by Grid West to satisfy the NERC and WECC criteria
- The reserve market clearing will occur after the close of the day-ahead transmission scheduling process
- Congestion regions within the CCA will be used where and when required

2.0 PURPOSE

The purpose of this white paper is to review the proposed reserve market design for the Grid West Consolidated Control Area (CCA).

3.0 BACKGROUND

Currently, reserves are carried by individual control areas based on standards set forth by the Western Electricity Coordinating Council (WECC) and the North

[1] IOS are the services used to meet a control area's ancillary services requirements, including operating reserves. IOS and reserves are used interchangeably within this document.

[2] 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.

American Electric Reliability Council (NERC). As a part of Grid West's Basic Features, at least three control areas are expected to consolidate. One of the benefits of consolidation is the ability to pool regulation requirements. This will lower the amount of regulating reserve required.[3] With the formation of a central reserve market, active participation by service providers is expected and Grid West will be able to procure both regulating reserve and contingency reserve at the lowest cost. Non-consolidating parties will continue to make their own reserve arrangements.

4.0 DESCRIPTION OF THE CCA RESERVE MARKET

The primary objective of Grid West's reserve market is to use a market mechanism to efficiently schedule capacity resources at the lowest cost to meet the reserve requirements of the CCA system. To administer the CCA reserve market, Grid West will determine the required reserves for the CCA system, accept offers, calculate obligations of the Transmission Customers[4], determine winning offers and prices, and settle the market.

4.1 Products

Grid West will procure the following reserve products for the CCA:

- Regulating reserve
- Contingency reserve – spinning
- Contingency reserve – non-spinning

Regulating reserve is an amount of spinning reserve immediately responsive to Automatic Generation Control (AGC) capable of providing sufficient regulating margin to meet NERC Control Performance Standards 1 and 2 (CPS1 and CPS2). It must meet the technical and certification requirements[5] defined by Grid West. Grid West will determine the total requirement for regulating reserve.

Contingency reserve is operating reserve in addition to the regulating reserve requirement sufficient to meet the NERC Disturbance Control Standard (DCS). At least half of the contingency reserve requirement must be spinning

[3] California ISO estimated a reduction of 100 MW of upward regulation capacity for a 1 year period would have saved over $9.5 million. See "ISO Metered Subsystem (MSS) Option Proposal for Western Area Power Administration –Sierra Nevada Region (Western)", April 7, 2003.
[4] If IOS are not offered in the DA market sufficient to meet Grid West's CCA requirements, CCA LSEs will be required to offer IOS as necessary to provide adequacy.
[5] To be addressed in the next layer of TSLG work.

reserve, which can be provided by generators and interruptible/dispatchable loads that are immediately responsive to system frequency and can be fully effective within 10 minutes.

Non-spinning reserve (the remaining part of the contingency reserve requirement) can be provided by generators and interruptible/dispatchable loads that can be fully effective within 10 minutes.

Grid West will need to consider the technical requirements and necessary process (such as dynamic scheduling transfers) to allow resources outside the CCA system to participate in the CCA's reserve market. Grid West will also consider tagging requirements for reserve schedules outside the CCA system.

4.2 Total Reserve Requirements

WECC has established Minimum Operating Reliability Criteria (MORC). MORC addresses the requirements for appropriate regulation performance, contingency reserves, and other reliability standards. As the operator and Balancing Authority of the CCA, Grid West will operate a day-ahead reserve market to procure the necessary reserves to meet the applicable standards to ensure reliability.

Grid West will determine the amount of spinning and non-spinning reserve necessary to comply with WECC's MORC. For regulation, a percentage of forecasted or scheduled demand will generally be used as the total requirement. The percentage will be developed by evaluating the behavior of the loads and resources.

Table 4.2 summarizes the total requirements for each reserve type. In accordance with MORC, the load carried by firm imports is not used in the contingency reserve calculation. In addition, since there are no absolute standards by NERC and WECC on the requirements of regulating reserve, the proposed requirements are discretionary and evolving in nature.

Table 4.2 -- Reserve Requirements

Reserve Product	Total Requirements
Regulating reserve	• A percentage of scheduled or forecasted demand.
Contingency reserve – spinning	• A minimum of 50 percent of the contingency reserve requirement, where the

	requirement is the higher of: ○ 5 percent of load responsibility[6] carried by hydro and/or wind generation and ○ 7 percent of load responsibility carried by thermal and other generation, **or** ○ MSSC (most severe single contingency) in the system[7]
Contingency reserve – non-spinning	• The balance of the contingency reserve requirement not covered by spinning reserve, plus interruptible imports[8] and on-demand obligations[9].

4.3 Reserve Market Timing

Reserve auctions will be conducted as part of the day-ahead scheduling process. Grid West will conduct the reserve auction after the day-ahead schedules are finalized. However, those using Injection/Withdrawal Rights (IWRs) should submit their reserve offers along with their schedules[10].

4.4 CCA Reserve Obligation for Regional Schedules

While Grid West's transmission services cover the entire Grid West Managed Transmission System (GWMT), Grid West's reserve market serves to meet the needs of only the CCA. Because of this, not all Transmission Customers will be obligated to pay for the costs of the CCA reserve market or to offer a share of the required reserve if an offer obligation is called upon (as will be discussed in Section 4.5). As a result, there will be a need for Grid West and Transmission Customers to determine responsibility for reserves based on the nature of Transmission Customer transactions.

[6] Load responsibility includes firm export schedules.
[7] As a participant in the NWPP Reserve Sharing Group, Grid West is expected to be exempt from the MSSC requirement.
[8] Although Grid West's regional schedules are firm, it is possible that a schedule involving Grid West and other control areas may have interruptible segments in another control area.
[9] On-demand obligations are defined as "firm contractual sales of reserve obligation(s) for which the receiver has the right to call upon with notice of ten (10) minutes or less during the hour of delivery." See WECC "Reliability Criteria: Part iii - Minimum Operating Reliability Criteria", //www.wecc.biz.
[10] To be addressed in the next layer of TSLG work.

Table 4.4 describes when a Transmission Customer's schedule is obligated to the CCA reserve market as a function of the schedule's injection and withdrawal points.

Table 4.4 -- CCA Reserve Obligation

Schedule	Injection Point Location	Withdrawal Point Location	CCA Reserve Obligation
Internal	CCA	CCA load	Yes
Export firm	CCA	Outside CCA	Yes
Import firm	Outside CCA	CCA	No
Non-CCA	Outside CCA	Outside CCA	No
Wheeling	Outside GWMT	Outside GWMT	No

4.5 Reserve Market Resource Participation

Grid West will procure necessary reserve capacity from voluntary offers of IOS. If there are insufficient IOS offers to meet Grid West's total requirements, Grid West will request additional offers from Transmission Customers (load-serving entities (LSEs) within the CCA) whose offers are below their obligation.

4.6 Self-provision

Self-provision of reserves is not explicit in Grid West's reserve markets. A Transmission Customer can achieve the same objective as self-provision by making reserve offers equal to its reserve requirement and acting as a price taker, i.e. offering reserve capacity at a minimum price[11]. Existing Transmission Customers who self-provide reserves can continue to do so through their Transmission Owners if they so desire.

4.7 Congestion Regions

Grid West will recognize congestion regions whenever there is actual or potential internal congestion within the CCA. Grid West will procure the required reserve products for each congestion region as necessary. For each of the reserve products, Grid West will evaluate the anticipated congestion within the CCA system using the day-ahead proposed schedules and the historical patterns of transmission use to determine if the product will be acquired on a CCA-wide basis or on a smaller congestion region basis. Grid West will make available the congestion region information to Grid West

[11] To be addressed in the next layer of TSLG work.

participants. Since costs for reserve services in constrained areas may be higher, charges to LSEs may vary by the location of load served.

4.8 IWR Submission for External Resources

For offers to be delivered from a location within the CCA, no IWRs are needed. For resources located in another host control area, Grid West will accept IOS offers having the ability to deliver the service to the CCA boundary or internal points.

Grid West accepts the following types of IWRs for reserve offers from external resources:

- IWR from external injection point to a withdrawal point within CCA, or
- IWR from external injection point to an aggregated withdrawal point within CCA[12].

Grid West will consider the IWRs associated with the IOS offers in assessing transmission availability for delivering the services.

4.9 Reserve Sharing

Grid West's participation as a member of the Northwest Power Pool Reserve Sharing Group is discussed in the Reserve Sharing white paper.

4.10 Reserve Market Evaluation and Clearing Price

Offer evaluation will be based on the following rules:

- Day-ahead offers will be evaluated independently for each of the 24 settlement periods of the operating day and for each congestion region if used;
- Grid West will determine the winning offers simultaneously for the three reserve products;
- Grid West will select the offers with the lowest capacity prices as winning offers[13];
- The clearing price for a reserve product for a settlement period and for a location will be the highest capacity price of the winning offers.

[12] We assume that Grid West will allow IWRs from an injection point to an aggregated location such as zones, areas, CCA, etc.
[13] Generally, Grid West uses only capacity offer prices to determine winning offers. However, Grid West may consider energy prices in the reserve offer if the deployment of reserve has a major negative impact to the real-time imbalance prices.

4.11 Cost Recovery

The costs of reserves will be allocated to the parties whose needs are met by Grid West. Metered load values [14] will be needed for the allocation (interchange schedules will be deemed delivered). However, since the type of resources used to supply the demand influences the allocation calculation, the allocation will be based on a computed allocation quantity, as described in Table 4.11 below.

Table 4.11 -- Reserve Costs Allocation Quantity

Reserves	Cost Recovery Allocation Quantity
Regulating reserve	Metered load value
Spinning reserve	Contingency obligation= 5 percent demand carried by hydro and/or wind generation, 7 percent demand carried by thermal or other generation, 0 percent load carried by firm import
Non-spinning reserve	Contingency obligation= 5 percent demand carried by and/or wind generation, 7 percent demand carried by thermal generation, 0 percent demand carried by firm import, 100 percent carried by interruptible imports

An overview of the cost allocation process follows.

- Grid West computes the allocation quantities for each customer after receiving all the metered values for each settlement period, each reserve product and each location (congestion region), using the formula described in Table 4.11.
- Grid West computes the total allocation quantities for each settlement period, each reserve product and each location.
- Grid West computes the share fraction for each customer, each reserve product, each settlement period, and each location. The share fraction is the ratio of the customer's allocation quantities to the total allocation quantities of the relevant product, period and location.

[14] In the next layer design, Grid West will look into various metering arrangements such as where generations are behind the load meters and decide if any adjustments to the metered values are needed.

- The cost for a customer is the product of the total cost and relevant share fraction of each settlement period, each reserve product and each location.

5.0 ROLES AND RESPONSIBILITIES

Grid West will:

- Manage the certification process of reserve resources
- Determine the reserve requirements
- Notify Transmission Customers whose offers are below their obligation when total reserve offers are insufficient to meet the total requirements
- Administer the reserve market auction
- Allocate the reserve costs to participants
- Implement dynamic transfers for reserve resources external to CCA

The Transmission Customers will:

- Inform Grid West how their reserve share will be provided if required by Grid West
- Pay their share of reserve market costs to procure reserves

The reserve service providers will:

- Offer reserves and
- Follow Grid West dispatch instructions for awarded reserves[15]

The host Balancing Authority of external reserve service providers will:

- Coordinate with Grid West for dynamic schedule implementation

6.0 MARKET BENCHMARKS

The design of the Grid West's reserve market will be functionally similar to the ancillary market of several RTOs (California ISO, ERCOT). The unique features for Grid West's reserve market are:

- Reserve offers will be voluntary unless a reserve shortage is determined by Grid West
- CCA system and GWMT have different boundaries

[15] Reserve deployment is discussed in a separate paper.

- Auction of the three reserve types[16] is simultaneous

Other markets, such as MISO and PJM, have developed integrated and centralized energy and reserve markets. Must offer obligations arise out of installed capacity markets or other long-term adequacy mechanisms.

7.0 TECHNOLOGY SOLUTIONS

A software application is needed for the reserve auction and required validation. The functionality can be part of the scheduling system.

8.0 COST DRIVERS

Costs associated with the reserve market operation will be mainly in the area of auction system software and personnel identified.

9.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *The need for RMR* - Grid West will need to answer the question how system reliability for the CCA is maintained when there are not sufficient resources offered into the markets. If responsibility rests with Grid West, RMR may be considered as one means to meet this responsibility.

- *Market power and monitoring* - Grid West will need to develop monitoring procedures to ensure market rules are followed.

- *Reserve schedule tags* - Grid West will need to study and determine if dynamic scheduling is to be tagged.

[16] CAISO switched from sequential auctions to “rational buyer” approach.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

During real-time operations, Grid West will deploy regulating reserve and contingency reserve obtained through the Reserve Market. These reserves will be deployed as part of Real-time Balancing Service (RBS) to respond to load changes, facilities outages, reserve-sharing events, etc.[1]

Highlights of this paper include:

- Grid West will deploy regulating reserve to meet North American Electric Reliability Council (NERC) Control Performance Standards.
- Grid West will dispatch balancing resources so regulation resources can maintain the required regulation capacity.
- During generation outages or activation of the Northwest Power Pool (NWPP) Pro Rata Reserve Sharing program (PRRS), Grid West will deploy contingency reserve as necessary to maintain system reliability.
- During normal operations, Grid West may use excess contingency reserve (spinning and non-spinning) as a source of imbalance energy if the reserve providers have agreed on such and if Grid West can maintain sufficient reserves to ensure reliability.

2.0 PURPOSE

The purpose of this white paper is to discuss the proposed reserve deployment design. Specifically, this paper discusses the deployment of both regulating reserve and contingency reserve during real-time operations.

3.0 BACKGROUND

Grid West, as the operator of the CCA, will procure regulating reserve and contingency reserve in the day-ahead process to meet CCA requirements. Contingency reserve includes spinning and non-spinning reserves.

[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.

Grid West will deploy these reserves in real-time operation as part of the Real-time Balancing Service (RBS). For regulation services, Grid West will issue Automatic Generation Control (AGC) signals to regulating resources to meet the Control Performance Standard (CPS) criteria. Contingency reserve is made up of spinning and non-spinning reserves, which are used during system contingencies in the CCA, or in the case of PRRS, elsewhere in the NWPP. If Grid West can still maintain sufficient reserves, part of the contingency reserve may also be used to reduce real-time imbalance energy costs.

4.0 DEPLOYMENT OF THE CCA RESERVES

4.1 Reserve Monitoring

During real-time operations, Grid West will monitor reserves in the CCA to verify adequate reserves exist to meet the reserve requirements per the Western Electricity Coordinating Council (WECC) standards.

The reserve requirements for real-time operations are evaluated based on real-time conditions and available reserve resources.

4.2 Deployment of Regulation

Grid West will automatically dispatch regulating reserve by sending AGC signals to generation owners. The CCA's Area Control Error (ACE) will be distributed to regulation resources according to a set of proportional participation factors.

Grid West will dispatch balancing resources so regulation resources will maintain the required regulating reserve capacity.

Regulating resources will not be used to set real-time imbalance energy clearing prices. However, the energy output associated with regulation resources will be settled based on the real-time imbalance energy clearing prices.

4.3 Deployment of Contingency Reserve

Grid West will deploy contingency reserve capacity to provide the required energy when any one of the following applies:

- An outage results in a capacity shortage within the CCA.
- A NWPP reserve-sharing member requests assistance through the PRRS.
- Other reserve obligations are called upon.

Grid West will dispatch all contingency reserve resources on a proportional basis if possible. It will also consider transmission constraints in deploying contingency reserve. During a contingency or activation of PRRS, contingency reserve resources will not set the real-time imbalance energy clearing prices.

The settlement price for the energy output from the deployed contingency reserve has not been determined. Two options have been identified:

1. The higher of applicable real-time locational imbalance price (LIP) or energy offer price; or
2. The applicable real-time LIP and a premium.

As a result of contingency reserve deployment, the CCA may become deficient of required contingency reserve. Under this condition, Grid West will dispatch available balancing resources as necessary to restore contingency reserve requirements within 60 minutes.

The details of the pricing methods are to be further investigated in the next development layer.

4.4 Deployment of Contingency Reserve in Normal Operation

When excess contingency reserve exists, Grid West may use the excess as a source of imbalance energy. However, the following conditions must be met:

- Grid West can maintain its required operating reserve margin per WECC standards
- The contingency reserve offer is not flagged as “contingency-only”
- The contingency reserve resources will benefit the CCA’s participants

When these conditions have been met, contingency reserve offers will be put into the balancing stack and will be deployed and settled in the same manner as other balancing offers.

In deploying contingency reserve, Grid West will ensure sufficient reserves are maintained. Grid West will also consider transmission constraints in deploying contingency reserve.

5.0 ROLES AND RESPONSIBILITIES

Grid West will:

- Issue AGC signals to regulation resources and monitor their performance
- Issue dispatch instructions for contingency reserve resources and monitor their performance
- Monitor and manage reserves in real-time
- Participate in the NWPP PRRS agreement
- Settle reserve and energy output
- Implement dynamic transfers for reserve resources external to CCA

The NWPP will:

- Continue to coordinate reserve-sharing implementation

Reserve service providers will:

- Follow Grid West's AGC signals or dispatch instructions

The host Balancing Authority of external reserve service providers will:

- Coordinate with Grid West for dynamic transfer implementation

6.0 MARKET BENCHMARKS

Other markets, such as MISO and PJM, have developed integrated and centralized energy and reserve markets. In an integrated market such as PJM, the reserve capacity clearing price is influenced by the capacity offer price, the energy price and its opportunity cost. Because of the high degree of integration of energy and reserve, reserve offers are considered to be part of the available economic resources allowed to set real-time clearing prices.

The design of Grid West's reserve deployment is similar to several existing RTOs (e.g., California ISO[2], ERCOT). The California ISO treats reserves in real-time the same as other economic balancing resources. However, the California ISO has a replacement reserve market and real-time reserve sources for additional

[2] California ISO is in the midst of redesigning its market.

requirements if needed. Reserve deployment at ERCOT is based on the proportional principle similar to the proposed design for Grid West.

The unique features for Grid West's reserve deployment are:

- No replacement or supplemental reserve and
- NWPP reserve sharing participation

7.0 TECHNOLOGY SOLUTIONS

Regulation deployment is conducted using an AGC system. In the future, an improved method of AGC deployment may be considered.

Software for reserve monitoring and deployment of contingency reserve may need to be developed. Moreover, tracking of reserve deployment and reserve sharing must be in place for settlement purposes. Grid West will leverage existing software in its information system development.

8.0 COST DRIVERS

The reserve deployment process must be in place for reliable system operation. The costs drivers are related to market and operational systems and personnel.

9.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

- *Deployment under transmission constraint* - When transmission congestion is present to restrict the deployment from reserve resources, Grid West should modify the proposed procedures based on proportionality to avoid overloading the system and consider proper incentives for resources in the constrained location.

- *Ramp rate consideration* - In deploying reserve resources, Grid West will need to consider the different ramp rates of reserve resources in order to meet the system load and balance the system. In addition, Grid West will need to consider if rules are needed to provide incentives to resources having faster ramp rates.

- *Dynamic scheduling* - For resources outside the CCA, the implementation of dynamic scheduling will need to be developed.

- *Additional reserve needs after the day-ahead market* - When there is additional need for reserves after the day-ahead market due to outages or major changes to schedules or weather, Grid West must develop a means other than the day-ahead market to procure additional reserves to ensure reliability.

1.0 EXECUTIVE SUMMARY

Grid West will continue to participate in the current Northwest Power Pool (NWPP) Pro Rata Reserve Sharing program (PRRS).

Under Grid West, multiple Balancing Authorities within the Consolidated Control Area (CCA) will consolidate into one. As a result, the existing PRRS procedure will need to be updated. Grid West will work together with Northwest Power Pool and the Pacific Northwest Security Coordinator (PNSC) to revise the program. The PNSC has operational control of PRRS.[1]

2.0 PURPOSE

The purpose of this white paper is to discuss the impact of PRRS on the operation of the CCA.

3.0 CURRENT RESERVE SHARING

The reserve sharing program in the Grid West region is currently managed by the NWPP, a voluntary and member-based organization. The benefits of reserve sharing include a reduced contingency reserve requirement for members of a reserve sharing group.

The PNSC performs real-time monitoring, accepts valid requests from participants, determines the appropriate reserve sharing obligations of participants, sends dynamic adjustments to members' net scheduled interchange (NSI) as necessary to effect energy transfers, and determines energy settlement amounts.

Real-time reserve signals are integrated directly into the Area Control Error (ACE) equations of the member Balancing Authorities. The integrated hourly values are used to generate interchange schedules that are used for settlement. Settlement can be either financial or physical (i.e., in-kind energy return).

[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.

4.0 GRID WEST RESERVE SHARING

Grid West will continue to participate in the NWPP PRRS program. The current sharing mechanism is tier-based: a priority order of participation is used based on the proximity of the requesting control area to its surrounding control areas and the availability of transmission capacity. For example, if an outage in BC Hydro's system results in activation of PRRS, resources from Alberta and Pacific Northwest Zone (including Oregon, Washington and Montana) are dispatched first. If more help is needed, resources from Idaho Power would be dispatched.

Because multiple Balancing Authorities will consolidate into the CCA, the existing procedures will need to be updated. Grid West will work together with the NWPP and PNSC to revise the program. It is expected that this revision will be relatively minor in nature. Grid West will be a member of the NWPP and meet the reserve obligation of its CCA. In the above example, if Idaho Power were part of the CCA PRRS would need to be modified to reflect this consolidation.

The following issues related to reserve sharing will impact Grid West's operations:

- **Transmission Reliability Margin** (TRM): In a case where Grid West is requesting help from PRRS, it must have available transmission capability for such purposes. Therefore, to the extent that Grid West chooses to rely on PRRS it must ensure sufficient transmission capacity for this purpose. This could impact the calculation of Available Flowgate Capability (AFC) and the Transmission Rights Reconfiguration Service (RCS) processes.

- **Settlement Prices:** Currently, energy settlement for reserve sharing is based on the daily Dow Jones Mid-Columbia Index for On-Peak and Off-Peak Firm Energy. Since this is different than the Real-Time Balancing Service (RBS) settlement price, Grid West may incur a shortfall or a surplus. However, since PRRS energy settlements are small, these price imbalances are not likely to be significant. Grid West could work with NWPP members to explore the possibility of using Grid West's RBS clearing prices for the energy settlement.

- **In-kind Return:** If energy settlement for reserve sharing is physical (i.e., energy output is to be returned in kind), Grid West will need to develop necessary tracking and settlement procedures.

- **Dynamic Transfers for External Resources:** When Grid West provides reserve energy during activation of PRRS, PNSC will adjust the CCA's NSI so that the CCA's internal resources will ramp up to produce the required energy. However, when the CCA has external resources that provide contingency

reserve, an additional adjustment to the CCA's scheduled interchange will be needed. Grid West will need to develop procedures to allow for dynamic adjustments to its interchange schedules.

5.0 ROLES AND RESPONSIBILITIES

Grid West will:

- Supply reserve under the NWPP Pro Rata Reserve Sharing program as requested;
- Request reserve under PRRS when outages in the CCA exceed its contingency reserve obligation as defined by NWPP; and
- Settle reserve sharing energy according to the PRRS procedures.

The NWPP and PNSC will:

- Continue to coordinate reserve sharing implementation and
- Work with Grid West to update the program as needed.

6.0 TECHNOLOGY SOLUTIONS

The communication requirements to the PNSC can leverage existing systems. ICCP communication systems are used to communicate with the NWPP Reserve Sharing system.

7.0 COST DRIVERS

There are no major costs drivers for reserve sharing since this process is in place for many Transmission Owners.

8.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Congestion impact to reserve sharing* - Grid West will need to investigate if transmission capacity should be set aside in day-ahead and post-day-ahead for reserve-sharing purposes, and how the reserve sharing will be received or provided in real time when transmission capacity is insufficient.

- *Settlement prices* - Grid West will explore the possibility to use its real-time imbalance energy price to settle energy due to reserve sharing agreement.

- *Dynamic transferring of reserve sharing* - For reserve resources outside the CCA, the implementation of reserve sharing could be complicated depending on the configuration of the receiving and delivering control areas and dynamic scheduling arrangements.

SETTLEMENT – MODULE 3c

CCA Settlement Metering – Describes the process associated with the collection and management of CCA settlement meter data including what data is required and who is responsible for providing it.

Settlement & Invoicing – Describes the proposed process for market settlement and invoicing. The topics covered include settlement statements, periodic invoicing, payment issues, and an illustrative timeline for settlement and invoicing.

Dispute Resolution – Describes the proposed dispute resolution process for resolving settlement, billing disputes, certification and translation disputes.

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

As a part of the Grid West Basic Features, Grid West performs settlement for services it provides. Transmission Customers who use these services are billed accordingly by Grid West. The bills come in the form of settlement statements and invoices. In order to calculate some of the charges and credits found on the statements and invoices, Grid West needs to obtain settlement meter data. This paper describes the process associated with the collection and management of the Consolidated Control Area (CCA) settlement meter data. Additional metering requirements are discussed within the Real-Time Monitoring white paper.[1]

Highlights of this paper include:

- Grid West requires meter data to perform settlement of the CCA Real-Time Balancing Service (RBS)
- Grid West does not need meter data for Transmission Customers in non-CCA host control areas
- Grid West will leave the existing tie-line meters in place at boundaries between consolidating control areas
- Grid West will need tie-line metering data for bordering Balancing Authorities (BA)
- Generators in a non-CCA host control area will participate in the RBS through use of dynamic schedules—they will not need to submit generation meter data
- Appropriate meter data is required for the entire CCA, including:
    - Load meter data provided at an aggregated level (e.g., tie line meters, POD meters, etc.)
    - Generation meter data provided for each meter measured on the low voltage side of the transformer
- Load within the CCA should have revenue quality meters at the same level that it is scheduled (e.g., bus, load zone)
- Not all generators within the CCA need revenue quality meters, only those participating in the RBS
- In most cases, existing metering infrastructure should be sufficient

[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.

2.0 PURPOSE

The purpose of this white paper is to discuss the proposed settlement metering design. The scope of the paper includes defining what settlement meter data is required and who is responsible for providing it. This paper does not cover real-time monitoring (e.g., SCADA, ICCP, etc.) A separate paper has been created to cover these topics. See the Real-Time Monitoring white paper for additional details.

3.0 BACKGROUND

Currently, many existing control areas require hourly scheduling and conduct hourly imbalance calculations. To calculate imbalance, control areas require meter data. When Grid West is formed, at least three control areas are expected to consolidate to form the CCA. Similar to other control areas, Grid West will need meter data for generation, actual interchange and load to calculate hourly imbalance charges for the CCA. Transmission Customers within the CCA will be required to provide both generator and load meter data as appropriate. Transmission Customers in non-CCA host control areas will not be required to submit meter data to Grid West except for BAs bordering the CCA that are responsible for providing the tie-line meter data.

4.0 METERING STANDARDS

Grid West metering standards will apply only to those participating in Grid West CCA services. Examples of these standards include: metering accuracy, monitoring, and validation (VEE) processes. Metering Standards are not discussed in this white paper, but will be defined in subsequent layers of design.

.

5.0 METERING PROCESS

5.1 Overview

In order to perform settlement, Grid West needs three types of meter data:

- Generation meter data
- Load meter data
- Interchange meter data

5.2 Generation Meter Data

All generators within the CCA that participate in the RBS are required to have revenue quality metering. The definition of revenue quality will be covered in a subsequent design phase. Transmission Customers, or a designated third-party service provider (Metering Agent), must electronically submit generation (injection) data to Grid West through the Market Information System using the Electric Industry Data Exchange (EIDE) protocol. Generation data supplied to Grid West should be "net" injection values.

5.2.1 Unit and Site Metering

Generation can be metered at either the unit level or at the site/project level. For example, a combined cycle project can be modeled as two generators or as one. If it is modeled as one, it can only be offered into the reserve market or balancing service as a single unit and metering can be submitted at the project level. Alternatively, if it is modeled as separate units, each must be offered into the reserve market or balancing service separately and meter data must be submitted for each unit.

5.2.2 Jointly Owned Units

For jointly owned units, each Transmission Customer must coordinate the designation of a third-party service provider (Metering Agent) with the other owner(s), since this Metering Agent designation should be identical for each of the unit owners.

5.3 Load Meter Data

All loads within the CCA are required to have revenue quality metering. The definition of revenue quality will be covered in a subsequent design phase. Furthermore, load must be metered at the same granularity it is scheduled (e.g., bus, load zone). For example, assume Transmission Customer A submits a balanced schedule from Generator 1 to Load 2, where Load 2 is a specific load bus. Under this scenario, Transmission Customer A must submit load meter data for the specific load bus. In contrast, if Transmission Customer A submits a balanced schedule from Generator 1 to Load 2, where Load 2 is a load zone, the Transmission Customer is required to submit load at the load zone level. Load zones are discussed below.

Transmission Customers, or their Metering Agent, must electronically submit hourly load (withdrawal) data to Grid West through the Market Information System using the EIDE protocol.

5.3.1 Load Zones

To simplify the scheduling and settlement processes, load zones may be used. Load zones are defined as either the metered value associated with a set of load busses, or the load within a metered boundary including a set of load busses. For each zone, the load is calculated as either the total of all metered load busses in the zone, or the total metered generation within the zone minus metered net actual interchange. The creation of load zones occurs during the registration process. Typically, load zones will be similar to existing control area settlement areas.

5.4 Interchange Meter Data

In order to account for all energy, control areas are responsible for reporting net actual interchange. In addition, to the extent necessary for metering load zones, existing interchange meters between consolidating control areas that are internal to the CCA will need to be maintained and reported. These values are needed for settlement.

6.0 METER DATA EXCHANGE

Transmission customers participating in the CCA are required to electronically submit hourly meter data, as appropriate, to ensure timely settlement. Transmission Customers may submit meter data themselves or designate a Metering Agent to submit the data on their behalf. However, at all times, Grid West should maintain a financial, legal and operational relationship with the Transmission Customer. Once Grid West is in possession of the meter data, it is responsible for ensuring the data is acceptable for settlement.

7.0 TIMING

Grid West will perform at least two settlements for a given Operating Day. Settlement meter data is required for each settlement. The more quickly Grid West can collect meter data from Transmission Customers and neighboring Balancing Authorities, the more quickly it can perform settlement. In the proposed design, Transmission Customers and Balancing Authorities must submit meter data two days prior to the settlement of a given Operating Day. For example, if an initial settlement is planned for 10 days after the Operating Day,

meter data should be due eight days after the Operating Day. This gives Grid West two days to perform validation of the submitted data.

8.0 ROLES AND RESPONSIBILITIES

Table 8.1 provides an overview of the roles and responsibilities for settlement metering:

Table 8.1 – Settlement Metering Roles & Responsibilities

Timeline	CCA Transmission Owner	Grid West CCA Transmission Customer	Designated Metering Agent	Grid West
By two days after the Operating Day	▪ Submit actual interchange data	▪ Submit hourly generation meter data (DP) ▪ Submit hourly load meter data	▪ Submit hourly generation meter data (DP) ▪ Submit hourly load meter data	▪ Validate meter data

9.0 MARKET BENCHMARKS

Load meter data can be acquired using one of two different approaches. Under a centralized approach, load values are "built up" through a centralized aggregation process. The centralized model is commonly used in markets where retail choice is supported and individual service point metering is performed. In contrast, within the decentralized model, Transmission Customers within the CCA are responsible for aggregating (and integrating) meter data to the wholesale level prior to submitting it to Grid West. Since Grid West does not support retail choice, we recommend a decentralized metering model.

A comparison of the proposed meter data management process with existing RTO/ISO is given in table 9.1:

Table 9.1 – Settlement Metering Benchmarks

Attribute	Grid West	ERCOT	PJM	MISO
Retail vs. Wholesale	Wholesale	Retail	Wholesale	Wholesale
Profiling	No	Yes	No	No
Generation Metering	Submitted	Submitted & Polled	Submitted	Submitted
Load Metering	Load Zone (and Nodal)	Aggregated	Load Zone (and Nodal)	Load Zone (and Nodal)
Model	Decentralized	Centralized	Decentralized	Decentralized
Granularity	Load Zone (and Nodal)	Service Point	Load Zone (and Nodal)	Asset

10.0 TECHNOLOGY SOLUTIONS

The primary applications associated with the meter data management process are:

- Meter Data Acquisition & Storage System
- Market Information System
- Electric Industry Data Exchange (EIDE) Protocol

11.0 COST DRIVERS

The primary cost drivers for metering include:

- Metering standards (e.g. revenue quality requirements)
- Number of metering points
- Commercial model business rules
- Metering granularity

12.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

- *Load Zone Definition* – How will load zones be defined? Who will be responsible for defining them?

- *Load Zone Weighting* – How will the load zone prices be weighted (e.g., load weighted, time weighted)?

- *Nodal Settlement Implications* – Recently FERC has instructed PJM and other RTOs to develop approaches for settling loads at nodal levels. What, if any, is the impact to our metering methodology?

- *Residual Load* – Are there situations where the submitted load data do not match the Net Actual Interchange? If so, how are the MWhs accounted for?

- *Metering Standards* – Metering standards need to be defined for Grid West. For example, what is the definition of revenue quality?

- *Time Standard* – What time standard will be used for Grid West? How will daylight savings be accommodated?

(This page intentionally blank)

1.0 EXECUTIVE SUMMARY

As a part of the Regional Proposal, Grid West will provide regional and CCA services. Transmission Customers who use these services will be billed accordingly by Grid West. The bills come in the form of settlement statements and invoices. The description of each charge found on these statements/invoices will be defined within the protocols.[1]

Highlights of this paper include:

- Tariff billing for pre-existing services will continue to be performed by individual Transmission Owners.
- Market settlement will be performed using a hourly interval.
- Grid West will perform at least two settlements for a given Operating Day.
- Initial settlement is performed at least Y[2] days after the Operating Day.
- Final settlement is performed at least Z[3] days after the Operating Day.
- Ad-hoc re-settlement will be performed for exceptional circumstances.
- Settlement statements are generated daily – they are snapshots of a given Transmission Customer's net position for a given Operating Day.
- Settlement statements do not initiate the payment process.
- Invoices are summaries of settlement statements and are either generated weekly or monthly.
- Invoices initiate the payment process.
- Grid West will implement a standard Account Receivable process.

2.0 PURPOSE

The purpose of this white paper is to discuss the proposed market settlements and invoicing design. Tariff billing for new long-term service will be discussed in subsequent design phases. Dates contained within this white paper are illustrative. Dates may be modified later in the design process to meet the specific needs of Grid West and its Transmission Customers.

[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.
[2] Y depends on when meter data is available.
[3] Z depends on when the initial dispute period ends

3.0 BACKGROUND

Currently, Transmission Customers take Open Access Transmission Tariff (OATT) services from various Transmission Providers. They are billed for the services they use. As a part of the formation of Grid West, some Transmission Customers may take new and/or additional services from Grid West. These customers will receive statements and invoices from Grid West for those services. The charges for these services will be defined in the protocols.

4.0 GRID WEST MARKET SETTLEMENT

The Grid West market settlement process includes the financial settlement for Grid West regional and CCA services. This process is applicable to both new service and those taking optional Grid West services. Anyone taking service using existing contracts and not taking additional optional market services will not receive a statement/invoice from Grid West.

Transmission Customers meeting their System Access Requirement will have access to optional Grid West market services. Market settlement is concerned with the collection of charges and the distribution of payments associated with Grid West market services. Charges and credits resulting from market services will be calculated based on the regulated tariff that has been approved by the Federal Energy Regulatory Commission (FERC). These services include, but are not limited to:

- Reconfiguration Service
- Reserve Market Service
- Real-Time Balancing Service

Grid West will produce daily settlement statements. An initial and final settlement statement will be generated for each Operating Day. Settlement statements will include daily, monthly and annual charges as well as any administrative and miscellaneous fees. Each statement will consist of two parts: 1) statement summary 2) statement detail. Both will be posted to the Market Information System. Transmission Customers are responsible for retrieving them.

The settlement summary is intended to provide a high-level overview of a given Operating Day. It will include a net position for each charge type. The settlement detail is intended to provide enough detail such that Transmission Customers can verify their charges.

4.1 Grid Management Charge

Grid West must recover its operational costs (e.g., employees, systems and facilities) associated with providing Grid West services. Since many of the Grid West services are optional (e.g. Reserve Market), Grid West may chose to separate the Grid Management Charge into separate categories. Participants using various services will be charged a fee for the use of each service.

5.0 GRID WEST INVOICING

Market settlement does not initiate the payment process. Instead it provides a financial snapshot of a particular Transmission Customer's net position on a given Operating Day. To initiate the payment process, Grid West will generate weekly (or monthly) invoices and publish them on the Market Information System. Each invoice will be a summary of all of the settlement statements a Transmission Customer has received since the last invoice cycle. Each invoice will be prepared on a net basis and each Transmission Customer will be either a net payee or a net payer.

6.0 PAYMENT PROCESS

The payment process occurs in two steps:

1. Transmission Customer owing monies to Grid West will remit the amount shown on the invoice no later than the close of Business Day on the relevant payment date.

2. Grid West will calculate the amount available for distribution to Transmission Customers. Grid West will make payments no later than the Business Day following the invoice due date.

If a Transmission Customer does not pay in full, then Grid West will not collect enough monies to pay out all obligations. Grid West may implement a "short-pay" process under these conditions. The short-pay process will be designed as a part of subsequent design phases.

7.0 SETTLEMENT AND INVOICING TIMELINE

Market settlement occurs along a fixed timeline. In developing its market settlement timeline, Grid West needs to determine how many settlements should be performed per Operating Day and when those should occur. The formation of the settlement timeline can be a significant cost driver. Timeline decisions

impact staffing levels and complexity. As Grid West develops its settlement timeline, several factors should be considered:

- Metering scope (centralized vs. decentralized)
- Payments/cash flow
- Quality of meter data
- Disputes timeline
- Credit impact
- Staffing impacts
- Complexity of charges and/or settlement statements
- Degree of automation

RTOs/ISOs perform multiple settlements per Operating Day for several reasons. The primary reason is because the inputs into the process change over time. For example, meter data may initially be estimated and later updated with actuals. Once the RTO/ISO has more accurate meter data, it typically executes another settlement run for the same Operating Day, and the Transmission Customer is billed for the difference in quantity between the estimated and actual meter readings. If the metered value does not change, the Transmission Customer's final bill would be zero. Additionally, participants are often concerned with risk management and cash flow. They want to understand their net position as soon as possible. Moreover, generators want to get paid for their services in a timely manner.

These interests are often at odds with one another. Timeliness and accuracy are tradeoffs. Most RTOs/ISOs have at least three settlements per Operating Day and the trend is to perform the initial settlement within 10 days of the Operating Day. However, Grid West does not support retail metering and meter data is an input to only one service (the Real-Time Balancing Service). Therefore, Grid West can likely initially operate the market with only two settlements per Operating Day. Finally, since there are no financial markets (e.g. virtual bidding, financial transmission rights), a 10-day settlement window may be acceptable to the parties involved.

Table 7.1 is an example of a potential Grid West settlement timeline:

Figure 7.1 – Illustrative Settlement and Invoicing Timeline

8.0 ROLES AND RESPONSIBILITIES

Table 8.1 provides an overview of the roles and responsibilities for settlement and invoicing:

Figure 8.1 – Illustrative Settlement and Invoicing Roles & Responsibilities

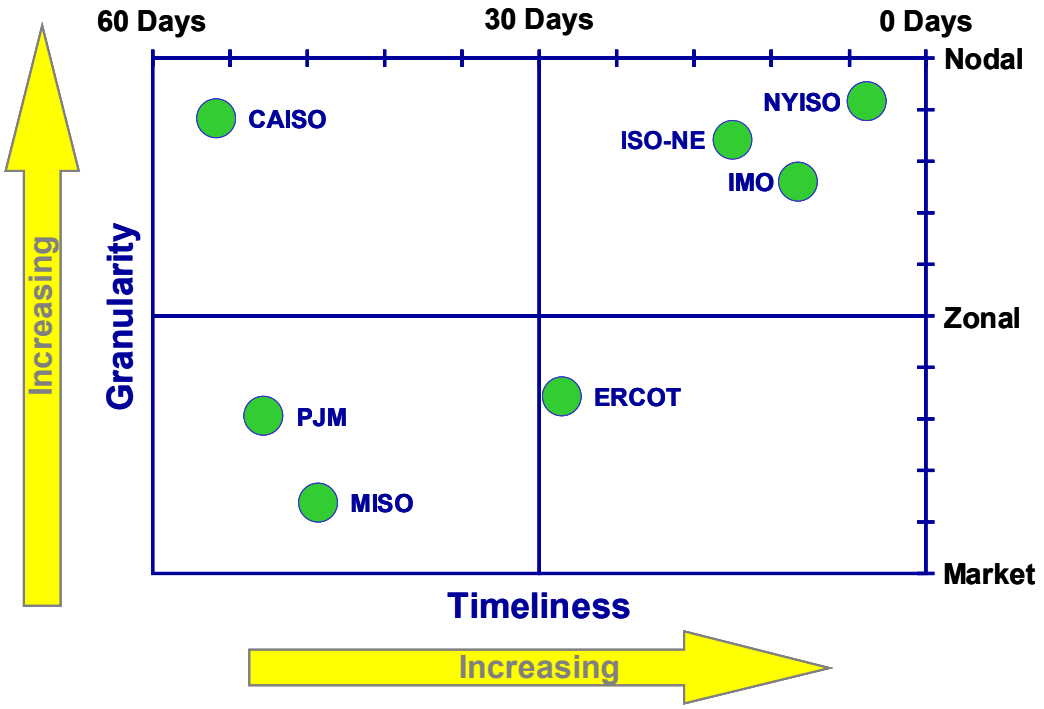
Timeline	Transmission Customer	Grid West
By two days after the Operating Day	▪ Submit hourly meter data ▪ Submit hourly load meter data	▪ Validate meter data
OD + 10 BD	▪	▪ Perform initial settlement ▪ Generate statement summary ▪ Generate statement detail
OD + 10 BD	▪ Download statement	▪
OD + 20 BD	▪ Submit dispute (if required)	▪
OD + 27 BD	▪	▪ Post dispute status
OD + 50 BD	▪	▪ Post dispute response
OD + 55 BD	▪	▪ Perform final settlement ▪ Generate statement detail ▪ Generate statement summary
OD + 55 BD	▪ Download statement	▪
OD + 65 BD	▪ Submit dispute (if required)	▪
OD + 72 BD	▪	▪ Post dispute status

OD + 95 BD	▪	▪ Post dispute response

9.0 MARKET BENCHMARKS

Table 9.1 provides a comparison of the proposed settlement process with other RTO/ISOs:

Figure 9.1 – Market Settlement Benchmarks



10.0 TECHNOLOGY SOLUTIONS

The primary applications associated with the settlement and billing process are:

- Settlement System
- Credit Management
- Risk Management
- Market Information System

11.0 COST DRIVERS

The primary cost drivers for settlement include:

- Settlement frequency
- Number of charge types
- Separation of Tariff Billing for Market Settlement
- Dispute process

12.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Paying Agent* - In Layer 3, the need for a paying agent will be considered, particularly with regard to tariff payments made for the collection of the Transmission Owners' fixed costs. In the RTO West Stage 2 framework, a paying agent was found to be useful to minimize the movement of funds between parties and to assure that revenues were not diverted or applied to obligations other than those for which they were designated. A Paying Agent would be an entity retained under an agreement between Grid West and a Transmission Owner to receive, hold and distribute funds derived from Grid West's coordinated operations of the Transmission Owners' respective transmission systems

- *Credit Management* – Grid West Basic Features does not include a Day-Ahead energy market, financial rights, or virtual bidding. Therefore, it likely does not need a sophisticated credit management solution. However, additional analysis should be performed in the Layer 3 design.

- *Risk Management* – Does Grid West require a risk management system?

- *Short-pay Scenario* – In some cases, Grid West Transmission Customers may not pay their invoices in full. As a result, Grid West will not have collected enough funds to cover its obligations to the generators. What sort of short-pay process, if any, should be implemented?

- *Tariff Billing* – What will Grid West's role be in the settlement of long-term services?

- *Charge Type Definition* – What are the inputs, determinants, and outputs for each charge type?

- *Settlement Accuracy* –What degree of accuracy (e.g., significant digits) should be applied to settlement calculations?

13.0 APPENDIX A: ILLUSTRATIVE CHARGE TYPE MATRIX

Service	Sub-Service	Charge Type	Data Requirements
Reserve Service - CCA	Regulation	Regulation Up Capacity Payment to MP	• Awarded Regulation Up Offers • Regulation Up Clearing Price
		Regulation Charge	• Participant Regulation Requirement • Regulation Up/Down Clearing Price
	Non-Spinning Reserve	Non-Spinning Reserve Capacity Payment to MP	• Awarded Non-Spinning Reserve Offers • Non-Spinning Reserve Clearing Price
		Non-Spin Charge	• Participant Non-Spin Requirement • Non-Spin Clearing Price
	Spinning Reserve	Spinning Reserve Capacity Payment to MP	• Awarded Spinning Reserve Offers • Spinning Reserve Clearing Price
		Spinning Charge	• Participant Spinning Requirement • Spinning Clearing Price
	Black Start Service *	Black Start Payment to MP	• Black Start Contract Amount
		Black Start Charge	• Total Black Start Payments • Participant Load Ratio Share
Real-Time Balancing Service – CCA	Real-Time Energy Service	Real-Time Energy Payments to MP	• Awarded Offers by Participant • Real-Time Locational Price

		Real-Time Energy Charge	• Real-Time Locational Price • Dispatch Instructions • Generation Meter Data • Load Meter Data • Dead band • Uninstructed Deviation Penalty
System Access Requirements	N/A	System Access Charge	• Company Rate • Scheduled MWhs
Reconfiguration Service	Reconfiguration Service	Reconfiguration Payment	• Awarded Offers by Participant • Market Clearing Price
		Reconfiguration Charge	• Awarded Bids by Participant • Market Clearing Price
		Surplus Revenue Distribution to R3A	• Surplus Revenue • R3A

1.0 EXECUTIVE SUMMARY

As a part of the Regional Proposal, Grid West will provide both regional and CCA services. Transmission Customers who use these services will be billed accordingly by Grid West. The bills come in the form of settlement statements and invoices. Transmission Customers have the ability to dispute erroneous charges found within their statements and/or invoices. Additionally, Transmission Customers with pre-existing contracts may seek certification or translation of transmission rights to participate in Grid West markets. Billing, certification and translation disputes that cannot be resolved as a part of the Grid West dispute process may enter into a secondary dispute process or Alternative Dispute Resolution (ADR) process. The ADR process described here would be administered by a neutral third-party arbitrator.[1]

Highlights of this paper include:

- Grid West will manage the dispute resolution process for billing, certification, and translation disputes
- A neutral third party will manage the ADR process for billing, certification, and translation disputes
- Disputes are submitted through the Market Information System
- Disputes are submitted within 10 days[2] of the statement/invoice date
- Grid West evaluates disputes within seven days of receipt
- Grid West posts a resolution within 30 days of receipt
- Transmission Customers may move the dispute into ADR at the conclusion of the Grid West dispute process
- ADR decisions involving billing, certification and translation disputes should be made within 90 days of receipt

2.0 PURPOSE

The purpose of this white paper is to discuss the proposed dispute resolution design for billing, certification and translation disputes. Any dates contained within this white paper are illustrative. Dates may be modified later in the design process to meet the specific needs of Grid West and its Transmission Customers.

[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.
[2] These dates are illustrative. They may be changed to better address the needs of Grid West and/or its Transmission Customers

The ADR process for billing, certification and translation disputes may be distinct from the process used for other disputes under the Grid West Bylaws and Transmission Agreements. If a more general approach to all disputes is be developed as the tariff and transmission agreements are developed, that method may be applied rather than the process suggested here. The method suggested illustrates how billing, translation and certification disputes could be resolved in the absence of a more comprehensive Grid West ADR process.

3.0 BACKGROUND

Currently, Transmission Customers receive bills for Open Access Transmission Tariff (OATT) services provided by various Transmission Providers. If Transmission Customers disagree with their charges, they can dispute them with their Transmission Provider under the provisions of their tariff. Additionally, if the Transmission Customer and Transmission Provider are unable to come to a resolution, they may enter into an arbitration process. This process will remain the same for Transmission Customers that continue to receive pre-existing OATT services from Transmission Owners.

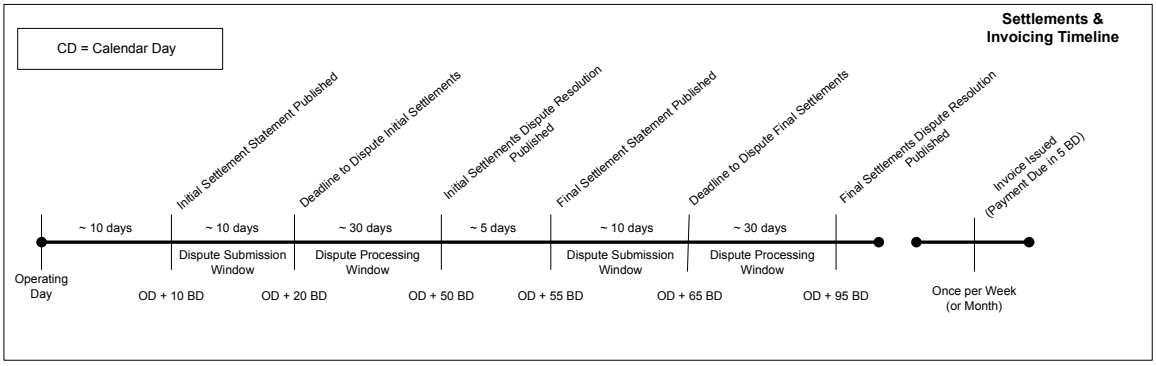
As a part of Grid West's Basic Features, Transmission Customers may take service from Grid West. Certain services, such as Reconfiguration, may require Transmission Customers to certify and/or translate their existing transmission rights. Transmission Customers will have a process for disputing the results of the certification and/or translation. Additionally, Transmission Customers will be able to dispute the charges found on settlement statements/invoices. The dispute resolution process for these types of disputes will be centralized and managed by Grid West.

4.0 GRID WEST DISPUTE PROCESS

4.1 Billing Disputes

Grid West will produce both settlement statements and invoices for services it provides to Transmission Customers. Statements are typically generated daily. They provide a snapshot of each Transmission Customer's net position for a particular Operating Day. Invoices are generated either weekly or monthly. They summarize a week's or month's worth of settlement statements for each Transmission Customer and trigger the payment process. Table 4.1 provides an overview of the proposed settlements and invoicing timeline.

Figure 4.1 – Illustrative Settlements and Invoicing Timeline



Both statements and invoices include a set of charges related to specific services. Transmission Customers may dispute any of the charges contained within a statement or invoice. Additionally, Transmission Customers may dispute the determinants and calculations they believe are incorrect. Errors occur for a variety of reasons, including: 1) inaccurate meter data, 2) inaccurate prices, and 3) inaccurate calculations. However, Transmission Customers should remit payments in full for disputed charges. For systemic errors (e.g., metering errors), special timelines may apply.

A Transmission Customer initiates the billing dispute process by submitting a dispute through the Market Information System. Billing disputes should be based on the current approved version of the protocols. Grid West will evaluate each received dispute for completeness. Since statements and invoices contain hundreds of line items, each billing dispute should be submitted with at least a minimum amount of information, including:

- Operating Day
- Statement/Invoice ID
- Settlement Interval
- Charge Type
- Billing Determinant
- Reasons for Billing Dispute
- Requested Remedy
- Supporting Data

4.2 Certification or Translation Disputes

Transmission Customers with pre-existing contracts seeking certification or translation of their transmission rights can use the dispute resolution process to resolve any dispute arising from the certification or translation process.

4.3 Dispute Administration

Grid West will manage the dispute process for billing, certification and translation disputes. It has several responsibilities including notifying all parties involved in a billing dispute, evaluating/reviewing disputes, and tracking the status of a dispute.

After a dispute is submitted, it is evaluated for completeness. If the dispute is not complete (e.g. missing information), it may be sent back to the Transmission Customer. If the billing dispute is timely and complete, Grid West will accept it and initiate the review and evaluation process. To minimize costs, Grid West should make all reasonable attempts to resolve disputes during the Grid West billing dispute period.

4.4 Dispute Resolution

If Grid West grants a Transmission Customer's billing, certification or translation dispute, it may take the following actions depending on the type of dispute:

- Billing Dispute - an adjustment will be made, as needed, to the next settlement statement or invoice. In some extreme cases, a resettlement of the entire market may be required.
- Certification Dispute – an adjustment will be made to the Transmission Customer's existing rights certificate.
- Translation Dispute – an adjustment will be made to the Transmission Customer's Injection Withdrawal Right value.

5.0 ADR PROCESS

Transmission Customers who don't resolve their billing, certification or translation dispute through the Grid West dispute process described above will have the option of moving their dispute into the ADR process. However, not all disputes can be moved to the ADR process. Only disputes that fall within a pre-defined list of "actionable" ADR events can enter into the ADR process. These events should be defined within the Grid West protocols.

The ADR process will be administered by a neutral arbitrator. The proceedings are confidential and the results are legally binding. For billing disputes, the cost of the proceedings will be assigned to the non-prevailing party or as otherwise determined by the arbitrator. For certification or translation disputes, each party

will bear its own costs plus a share of the arbitrator's costs as determined by the arbitrator.

6.0 ROLES AND RESPONSIBILITIES FOR BILLING DISPUTES

Table 6.1 provides an overview of the roles and responsibilities for billing disputes:

Table 6.1 – Dispute Roles & Responsibilities

RCS Timeline	Transmission Customer	Grid West	Arbitrator
Within 10 days of the statement or invoice	▪ Submit billing dispute		
Within 7 days of receiving billing dispute		▪ Review/evaluate billing dispute ▪ Post initial dispute response ("Open", "Deferred", etc.)	
Within 30 days of receiving billing dispute	▪ Submit additional dispute information, as required	▪ Gather required dispute information ▪ Evaluate the merit of the dispute ▪ Publish dispute resolution ▪ Perform misc adjustment, if required ▪ Resettle the market, if required	
Within 10 days of dispute resolution	▪ Submit ADR request to the Grid West Arbitrator		
Within 7 days of ADR request			▪ Review/evaluate ADR request ▪ Post initial ADR response ("Open", "Deferred", etc.)
Within 90 days of ADR request			▪ Publish ADR resolution

7.0 MARKET BENCHMARKS

Table 7.1 provides a comparison of the proposed dispute process with existing RTO/ISOs:

Table 7.1 – Dispute Benchmarks

Design Attribute	GRID WEST[3]	ERCOT	SPP	MISO
Dispute Timeline	▪ 10 Business Days	▪ 10 Business Days	▪ 10 Business Days	▪ 10 Business Days
Dispute Medium	▪ Submitted through the Market Information System	▪ Submitted through the Market Information System	▪ Submitted through the Market Information System	▪ Submitted through the Market Information System
ADR Process	▪ Yes	▪ Yes	▪ Yes	▪ Yes
ADR Decision Period	▪ 90 Days	▪ 120 Days	▪ 90 Days	▪
ADR Cost Allocation	▪ Each party shall be responsible for its own costs incurred during this ADR Procedure and for a pro rata share of the cost of the mediator or arbitrators	▪ Each party shall be responsible for its own costs incurred during this ADR Procedure and for a pro rata share of the cost of the mediator or arbitrators	▪ Each party shall be responsible for its own costs incurred during this ADR Procedure and for a pro rata share of the cost of the mediator or arbitrators	▪

8.0 TECHNOLOGY SOLUTIONS

The primary applications associated with the billing dispute process are:

- Dispute Tracking System
- Market Information System

[3] Proposed dates. Dates may change in subsequent layers of design.

9.0 COST DRIVERS

The primary cost drivers for disputes include:

- Degree of automation
- Accuracy of market/commercial system calculations

10.0 DESIGN ISSUES FOR CONSIDERATION IN NEXT DEVELOPMENT LAYER

The next layer of design should include a review of the following design issues:

- *Certification/Translation Dispute Resolution* - Details of the dispute resolution process for certification and translation ADR to be developed later.

(This page intentionally blank)

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.

(This page intentionally blank)

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

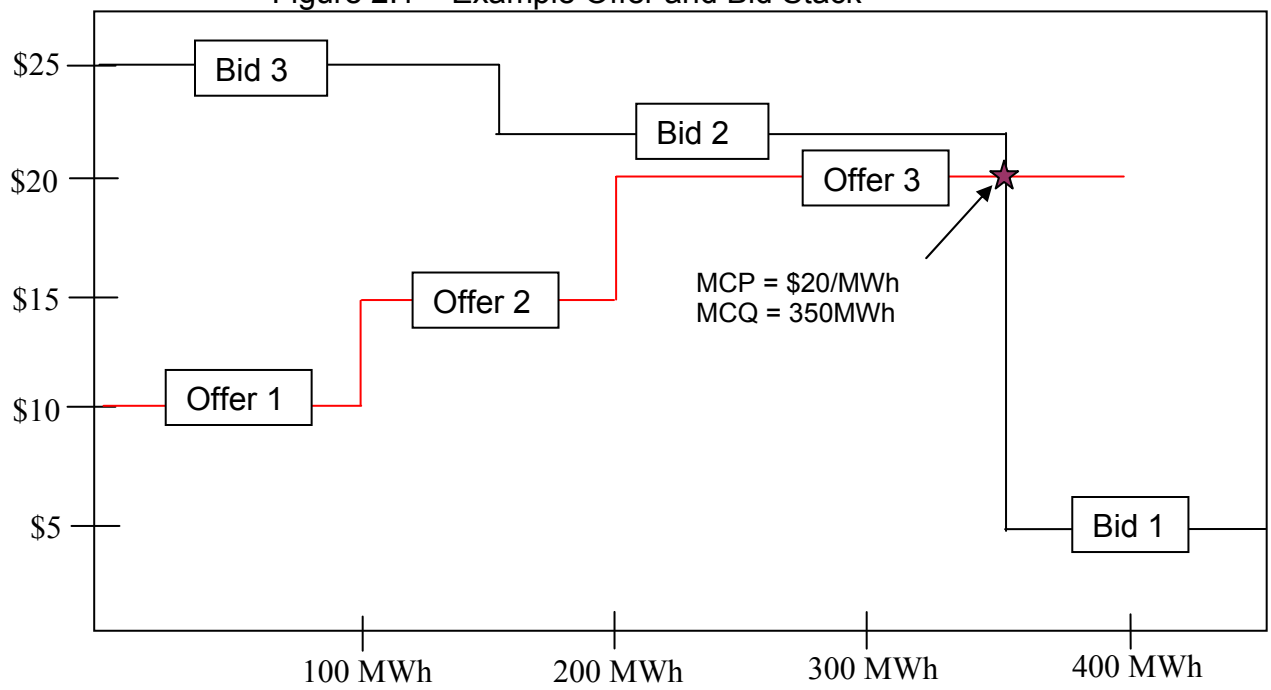
Table 2.2

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.]

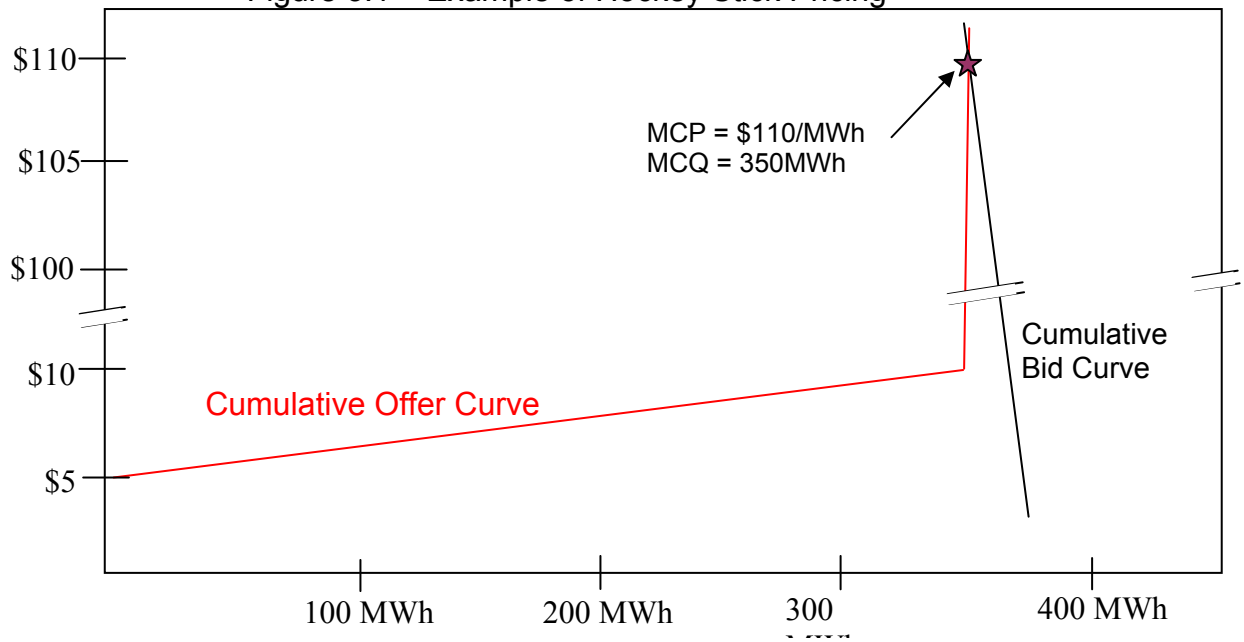
- *AOP can increase cost of participation in the market:* Another inefficiency introduced by AOP pricing is the cost associated with forecasting market prices. Under MCP pricing, sellers offer their supply at marginal/opportunity costs, which are readily available. AOP pricing introduces uncertainties 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.

(This page intentionally blank)

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.
.

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.

---

[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.