Preliminary Report on
The Estimated Benefits of Grid West

July 19, 2005

Seminar Review Draft

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1. Executive Summary

The Grid West Risk/Reward workgroup (RR workgroup), which formed under the auspices of the Regional Representatives Group (RRG) in 2004, had responsibility to estimate the benefits related to Grid West formation.[1] The analytical work has been focused on regional (net societal) impacts associated with Grid West's Basic Features and organizational structure.[2]

Building from the "problems and opportunities" document developed by the RRG in the summer of 2003, the RR workgroup undertook three areas of study:

(1) review existing studies that evaluated costs, benefits and risks;

(2) quantify the impact of the RRG-identified problems (to the extent possible); and,

(3) research the operating costs of ISOs and RTOs.

Due to time and budgetary limitations, the RR workgroup chose not to directly engage in production cost modeling, but considered the merits of reporting results from other modeling and research efforts.[3]

The RR workgroup's report is not meant to provide a single nor decisive benefit estimate – instead, it is intended to provide a menu of potential benefits, assumptions, and analytical methods upon which RRG participants can draw in making their own assessment of Grid West's benefits. The estimated benefits focus on what Grid West can accomplish by addressing transmission challenges as an independent entity, rather than what can be accomplished by changing the organizational roles and functions of existing institutions.

The purpose of this report is to inform the RRG and regional stakeholders of the potential range of benefits associated with Grid West for Decision Point 2. Decision Point 2, the decision scheduled for fall 2005, will determine whether or not to seat and fund an independent five-member Developmental Board elected by Grid West membership for two years and continue development of Grid West during that time.

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1 The workgroup roster can be found at: www.gridwest.org/Doc/RnR_Drafts/Risk-Reward-Group-List.doc.

2 Grid West "Basic Features" are defined in the documents of the Transmission Service Liaison Group (TSLG) which can be found at http://www.gridwest.com/TSLG_May2005Papers.htm.

3 The Grid West Risk-Reward Group Charter – Work Plan Review (Draft 3/31/05). See www.gridwest.org/Doc/RnR_Drafts/Risk-Reward_Charter033105.doc. Note that this limitation was not intended to preclude production cost modeling efforts by individual group members.

As a foundational step to its work, the RR workgroup developed the Grid West Risk Reward Survey (survey) to gather detailed information and data about existing regional transmission problems identified by the RRG.[4] The survey, which was distributed to market participants in the Grid West area, posed 37 questions asking for perceptions about pancaked rates, transmission system operations, system capability and scope, transmission constraints, treatment of generators/loads, tariff and business practices and planning and expansion. Out of 33 potential respondents, 30 responses were received—a 91% response rate.

The survey responses reflected a wide range of viewpoints for each category of questions. The responses did not always correlate with the character of the responding entity (e.g., Major Transmitting Utility, Transmission-dependent Utility, etc.). Often the responses reflected the respondent's geographic location, business scope and, the entity's adequacy in terms of generating resources and transmission capacity. The survey provided input to Grid West market design work and helped identify elements to analyze for estimated benefits.

The quantitative benefit assessments (benefits) were compiled from individual members' analyses some of which initially focused on the benefits that could be realized by control area consolidation. These analyses were presented and reviewed by the RR workgroup. Although the assessment of benefits is preliminary, its level of detail is similar to that associated with the assessment of the market design and the pricing scheme that characterize Grid West. The assessment of benefits is intended to identify the categories of benefits that are expected and to quantify those categories to the extent possible. In those cases where benefits are expected but are difficult to quantify, a qualitative assessment is provided. In those cases where risks associated with the development of an entity such as Grid West have been identified, a qualitative assessment is also provided.

If regional parties decide to continue development of Grid West past Decision Point 2, more detailed analysis of the benefits, costs and risks will be necessary. Recommendations for further analysis are provided to guide this effort. In addition, some entities intend to evaluate the distribution of the costs and benefits among various regional entities. For example, the Bonneville Power Administration (BPA) anticipates using the Energy2020 model for this purpose.[5]

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4 The RRG document summarizing the transmission problems and opportunities the RRG identified though its work in 2003 is available on the Grid West Website at: www.gridwest.org/Doc/Reference_Document_Sept52003.pdf.

5 Energy2020 dynamically models markets and is anticipated to be used by BPA to evaluate the distribution of costs and benefits associated with Grid West. See appendix file 20050616_E2020_Status.ppt

1.1. Preliminary Results

This report describes seven areas of benefits that have been quantified and eight areas of benefits that are described qualitatively. Significant effort was made to distinguish among the benefit categories that are quantified to eliminate overlapping benefits and minimize double-counting. For example, production cost savings determined during real-time (see Redispatch Efficiencies) are distinguished from production cost savings that could be realized through the elimination of rate pancakes (see Price Pancakes).

The benefits are calculated for two different control area consolidation scenarios: a 4 control area scenario (BPA, Idaho, PacifiCorp's east and west control areas) and a 10 control area scenario (BPA, Idaho, PacifiCorp's east and west control areas, Avista, British Columbia Transmission Corporation, NorthWestern, Portland General Electric, Puget Sound Energy and, Sierra Pacific). In addition, a range of benefits (High/Medium/Low) have been developed based upon various analytical methods and assumptions.

1.1.1. Contingency Reserves

This element addresses the ability to reduce the quantity and the per unit cost of generation capacity that is synchronized to the system, unloaded, in excess of the quantity required to serve current and anticipated demand and, which is able to immediately respond and is fully available within ten minutes to serve load. This category includes both spinning and supplemental reserves. These benefits are to be distinguished from the benefits of pooling reserves, which have already been realized through the Northwest Power Pool. ***The capacity cost savings associated with Grid West managed contingency reserves ranges from $20 million to $73 million per year.***

1.1.2. Regulating Reserves

This element addresses the ability to reduce the quantity and the per unit cost of providing generating capacity with regulating response capability that is required to be placed under Automatic Generation Control (AGC) and which enables continuous balancing among control area resources to continuously match minute-to-minute load variations. Potential benefits could be derived from: (1) pooling regulating reserves; (2) capturing load diversity thus reducing the amount of regulation needed; and, (3) having access to a broader selection of units to use for regulation and therefore, reduce the cost. Also, by having access to the most economic units to carry the reduced amount of reserves needed, additional savings can be obtained through utilization of the residual capacity to meet other reserve requirements or enable surplus sales opportunities. ***The estimated capacity cost savings associated with Grid West reducing the amount of regulating reserves ranges from $5 million to $26 million per year.***

1.1.3. Real-time Redispatch Efficiencies

As the operator of a single consolidated control area (which is expected to consist of at least 4 existing control areas), Grid West will dispatch a larger pool of generating resources, subject to physical transmission and security constraints, to meet unanticipated real-time load changes and to minimize the cost of dispatch for participating scheduled load. Also, as the operator of the Consolidated Control Area, it will operate a single Automated Generation Control (AGC). The quantitative benefit associated with Real-time redispatch efficiencies is derived from the ability to reduce the operating cost of serving load in real-time as a result of dispatching resources that are more efficient based on an understanding of actual (as opposed to anticipated and scheduled) transmission constraints and having greater access to more transparent information about the willingness of generators to buy or sell power. This, in turn, leads to lower fuel costs, lower thermal losses, and greater utilization of infrastructure capacity. ***The estimated production cost savings associated with Grid West managed real-time energy balancing redispatch ranges from $30 million to $412 million per year.***

1.1.4. Bulk Electric System Reliability – Cascading Disturbances

By having broad visibility of the power system operating state, analytical tools to assess grid security, and the ability to take coordinated, corrective actions to move flow conditions out of unsafe operating ranges, Grid West may reduce the probability of prolonged, region-wide system disturbances that could cause significant portions of the extra-high-voltage (EHV) transmission network to collapse and cease providing power delivery over a wide area. ***The estimated annualized value to the region of avoiding this type of disturbance (cascading) ranges from $27 million to $83 million per year.***

1.1.5. Power Delivery System Reliability – Momentary/Sustained Outages

In addition to major system disturbances that result in cascading, wide-area, and prolonged outages, the system is exposed to many more minor, non-cascading outages that affect local customers. The same broad visibility and approach to grid operation may also reduce the frequency of non-cascading outages at the transmission and sub-transmission level. Grid West will enable independent oversight, development and application of maintenance "best" practices and O&M standards, and coordination of maintenance outages. In addition, crew sharing is likely to reduce the frequency and duration of minor outages and improve reliability. ***Avoiding momentary (less than 5 minutes) or sustained events (longer than 5 minutes but shorter than 12 hours) related to non-cascading transmission events has an estimated annualized value to the region ranging from $17 million to $231 million per year.***[6]

1.1.6. Rate and Transactional Pancakes

This element addresses the reduction in production costs as a result of removing rate and transactional "pancakes." Rate pancakes refer to the practice of charging the embedded cost of a transmission owner's system or company area (usually their control area) for incremental transmission usage, so that transactions involving multiple control areas pay multiple or "pancaked" charges. ***The estimated increase in production costs from the existing practice of charging multiple or pancaked rates ranges from $3 million to $61 million per year.***

In addition to rate pancaking, transactional pancakes result when buyers of transmission services must contact multiple transmission owners in order to coordinate the delivery of energy. Grid West flow-based scheduling and reconfiguration service (RCS) administered through a single organization provides an alternative to contract path scheduling through multiple control areas. While this assessment of benefits considers benefits that may be derived from the RCS and flow-based scheduling, benefits that may be derived from reducing or eliminating "transactional pancakes" are only addressed qualitatively.

[6] Grid West will act as the "transmission authority" for all of Grid West even if only 4 control areas consolidate. As the transmission authority, Grid West will be the reliability authority for the entire Grid West footprint, therefore, it is arguable that the benefits assessment associated with the 10 CCA scenario applies also to the 4 CCA scenario.

1.1.7. Reconfiguration and Increased Transmission Utilization

The Grid West market and operational design is based on a flow-based model that aligns scheduled usage with physical transmission system realities. Transmission customers will have the ability to trade transmission rights (release for sale, and buy) through RCS with Grid West acting as the agent for issuing new transmission rights based on the physical capability of the transmission system. The RCS is designed to encourage increased trading of transmission rights between holders of transmission rights and those who want to obtain rights; enable a robust exchange of rights that now are often held by transmission customers but go unused. ***The estimated reduction in production costs from more efficient prescheduled interchange facilitated by RCS ranges from $18 million to $52 million per year.***

1.1.8. Summary of Quantified Benefits

The table below shows the preliminary ranges of benefits in millions of dollars per year associated with each functional category studied. The assessment of benefits in each category is dependent upon various analytical methods and assumptions, hence the High, Medium and Low estimates. The method and assumptions used for estimating results in each category are explained in greater detail in the body of this report and the attached appendices.

		4 Consolidating Control Areas				10 Consolidating Control Areas		
		High	Medium	Low		High	Medium	Low
	Cost Saving Category	$ million/year				$ million/year		
1	Contingency Reserves	39	30	20		73	55	37
2	Regulating Reserves	10	8	5		26	21	14
3	Redispatch Efficiencies (PowerWorld simulations)	61	56	41		412	332	105
4	Bulk Electric System Reliability - Cascading Disturbances	83	50	27		83	50	27
5	Power Delivery System Reliablity - Momentary, Sustained Outages (2002$)	98	58	17		203	119	36
6	Rate Pancakes (TCA, GridView, Henwood)	61	20	3		61	20	3
7	Reconfiguration-Transmission Utilization (GridView)	52	30	18		52	30	18

Notes:

- 4 Consolidating Control Areas - BPA, Idaho, PacifiCorp's east and west control areas)
- 10 Consolidating Control Areas - BPA, Idaho, PacifiCorp's east and west control areas, Avista, British Columbia Transmission Corporation,

NorthWestern Energy, Portland General Electric, Puget Sound Energy and, Sierra Pacific.

- Lines 3, 6 and 7 as well as lines 4 and 5 are categories that have potential for overlapping benefits. Study case assumptions and methods have attempted to eliminate or limit the potential for such overlap.

1.2. Qualitative Benefits

In the survey conducted by the RR workgroup, respondents from all segments of the industry and other affected stakeholders described experiences, perceptions and, in some cases, developed quantitative analysis of problems and opportunities associated with transmission that affect their organizations. Whenever possible, the responses were to provide quantifications that could be generalized to a system level impact. These were considered and included in the quantitative analysis sections above. The impacts that were not readily quantified, but are nevertheless perceived to have a material impact on stakeholders and should be considered at Decision Point 2, are described below.

1.2.1. Improved Transmission Planning

Grid West's transmission planning provisions should provide a more transparent and effective planning and siting process than the semi-coordinated, yet fragmented, processes it will replace. Benefits are expected to accrue due to the system-wide "one utility" planning model for grid expansion that includes a common service queue and coordinated plan for generator requests and load growth that will be adopted by Grid West.[7] This model will be informed by data that indicates the cost of congestion and the value of relieving congestion (with wires and non-wires solutions). Investment decisions needed for reliability will be supported by Grid West's "planning backstop".[8]

1.2.2. Construction Deferral

This element addresses the ability to defer construction, whether for reliability, economy or for resource integration purposes, as a result of improved utilization of transmission capability. The benefits associated with this element have not been quantified due to time and model limitations however, representative

[7] Responses to the Risk Reward workgroup survey indicated significant interest in the improvements in regional planning efforts and efficiencies that could occur as a result of Grid West. See appendix files RRSurvey_WhitepaperSupport_051905.doc and RRSurvey_preliminaryresults_031105.pdf.

[8] Grid West White Paper on Planning and Capacity Expansion, Draft July 11, 2005.

examples of the benefits that could accrue have been analyzed. Benefits result from the opportunity to delay investment and reduce the capital cost of adding transmission and generation capacity because of improved utilization of the existing system, increased ATC, and reduced bottlenecked generation. Also, deferral benefits may result from technological improvements, improved information about loads, and products of market innovation.

1.2.3. Conservation and Demand Side Management

The Grid West TSLG Market and Operational Design includes flow-based reserve and real-time balancing markets that will facilitate demand-side resource participation both in real-time and long-term resource planning. The estimated savings associated with energy conservation, and non-wires expansion, and demand side measures facilitated by Grid West ranges from $1 million to $61 million per year.[9]

1.2.4. Coordinated Generation and Transmission Maintenance

No benefit/cost studies to-date have addressed whether coordination of transmission maintenance scheduling will impact regional benefits. The survey identified perceived problems with transmission maintenance outage coordination that have commercial and economic consequences. Grid West will have sufficient data and analytical tools to optimize both generation and transmission outage scheduling, and as an independent entity, Grid West would not have inherent conflicts of interest or commercial bias in its assessments of maintenance outage schedules. Additional analyses should be conducted to determine whether Grid West could improve regional benefits through improvements to maintenance scheduling.

Grid West's coordinated outage function should provide a more transparent process than is currently used, and participants will be encouraged to look beyond direct benefits in their own outage plans, encouraging more efficient (with respect to system-wide impacts) outage schedules.

1.2.5. Load Following

Load following is the provision of generation and interchange capability needed in the operating hour in order to meet load variations not covered by regulation service. The quantitative benefit associated with load following could be derived

[9] See Section 7.3 for details.

from simulations, such as those modeled in PowerWorld, to determine if more efficient load following is possible by relying on the Real-time Balancing Service within a consolidated control area.[10]

1.2.6. Market Innovation

Benefits are expected to accrue from technological and strategic innovations made possible by the development of new transmission services and broader market participation in ancillary service markets.

1.2.7. Market Monitoring

Provision of information to an independent organization could enhance grid-wide detection, prevention and mitigation of market dysfunction. Some view market monitoring as a facilitating function that enables the other benefits rather than a function that provides cost savings. Other parties view the presence of a market monitor as a factor that may prevent or reduce the probability of abuse and that the reduced probability results in a quantifiable benefit.

A market monitor will help avoid market manipulation and unnecessary price spikes. Grid West's establishment of common, transparent markets for power transactions should uniquely enable the market monitor to identify possible abuses. Further, a grid-wide market monitor should help to correct for and avoid inadequate market design, anticompetitive behavior and market abuse.

1.2.8. Dispute Resolution

Benefits are expected to accrue as a result of common business practices, common interpretations of tariff terms and conditions, a common transmission service queue, and regionally-vetted outage and maintenance schedules.

1.3. Unquantified Risks

Potential risks associated with Grid West formation were identified and briefly discussed by the RR workgroup.[11] A detailed discussion of the potential risks is included in the section Unquantified Risk Elements.

[10] The PowerWorld simulations are described in the appendices, Section 9.2.

2. Organizational Outline

This remainder of this report is organized into the following sections:

- Background
- Modeling Tools and Methods
- Modeling Assumptions and Detailed Results
- Survey Results
- Qualitative Elements
- Unquantified Risk Elements
- Appendices
- Glossary of Terms

3. Background

The Regional Representatives Group (RRG) assembled the Risk/Reward workgroup (RR workgroup) in 2004. [12] The purpose of this workgroup was to conduct an analysis that focused on regional (net societal) impacts and to assess potential benefits associated with implementing the Grid West Basic Features and organizational structure.[13] This analysis was intended to address the problems and opportunities that the RRG members and others identified with the region's transmission systems in the summer of 2003.[14]

The RR workgroup had its first meeting in May 2004. The RR workgroup has since met as a group approximately 20 times. In addition, significant time has been dedicated to research, analysis and modeling efforts by various member organizations of the RR workgroup. Some of the efforts that have been used to inform this analysis include:

- the cost/benefit study performed by Tabors Caramanis and Associates study on behalf of Grid West (2002) using GE-MAPS [15];
- a survey of operating costs of ISOs and RTOs prepared by the Public Power Council;[16]

[11] The Risk Elements were largely taken from a speech prepared by Linc Wolverton (a member of the RR workgroup) for the Northwest Public Power Association RTO Conference.

[12] The workgroup roster can be found at: www.gridwest.org/Doc/RnR_Drafts/Risk-Reward-Group-List.doc.

[13] Grid West "Basic Features" are defined in the documents of the Transmission Service Liaison Group (TSLG) which can be found at www.gridwest.com/TSLG_May2005Papers.htm.

[15] www.gridwest.org/Doc/BenCost_031102_RTOWestBCFinalRevised.pdf. See also a critique of the TCA study and TCA's response to that critique at: TCA_RTOW_Benefit-Cost Study-Wolverton_(et_al)_Critique_020420RTOlw.doc and TCA_RTOW_Benefit-Cost-Response_to_Critique.pdf.

[16] http://www.ppcpdx.org/Tx/ComparativeAnalysisTWO.FINAL.pdf

- the Henwood Energy Services, Inc. study commissioned by Snohomish PUD with participation by a number of others;[17]
- the SSG-WI Transmission Path Utilization report;[18]
- the 2004 RMATS data effort;[19]
- the PowerWorld model which incorporates both Powerflow and Optimal Powerflow models and allows simulation of the transmission network operating states and electrical interconnections for input schedules, generation, transmission and load configurations;[20]
- the Energy2020 model which develops schedules, simulates resulting generation dispatch and evaluates how changes in market structure impact generation bidding strategies;[21]
- the GridView production cost model;[22]
- the Lawrence Berkeley National Lab study entitled, "Understanding the Cost of Power Interruptions to U. S. Electricity Consumers";[23] and,
- internal BPA studies regarding the impact that control area consolidation could have on the cost and quantity of regulation reserves.[24]

This preliminary assessment of benefits should be read together with the cost estimates developed by the RRG Transmission Services Liaison Group (TSLG) and The Structure Group. The cost estimate is a "bottom-up" estimate of the start-up and operating costs of Grid West based upon an implementation plan that will support the provision of regional services, the operation of a consolidated control area and conduct the functions of the organization.

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17 http://www.snopud.com/content/external/documents/gridwest/henwood_gridwestfinal.pdf

18 http://www.ssg-wi.com/documents/320-2002_Report___final_pdf.pdf ; http://www.ssg-wi.com/GeneralMoreDocuments.asp?wg_id=3

19 http://psc.state.wy.us/htdocs/subregional/Reports.htm

20 See powerworld.com

21 See included appendix file 20050616_E2020_Status.ppt

22 See included appendix file RnR_GridView.pdf.

23 http://certs.lbl.gov/pdf/55718.pdf

24 BPA staff, Warren McReynolds and Bart McManus prepared two different evaluations regarding the impact on regulation (see Section 9.1).

4. Modeling Tools and Methods

BPA and PacifiCorp modeling efforts, as well as research into what other entities have done, were used to inform the estimates of the benefits. The models and how they were used to support various assessments are described below.

Different models are being used because there are different types of benefits over different time frames. Production cost models, such as GE MAPS, ABB GridView, and Global Energy's ProSym are designed to analyze hourly production costs and cannot examine sub-hourly issues. PowerWorld can be used to examine some sub-hourly issues (balancing energy options) but regulation (10 second, or less, swings) or the cost of outages require a different approach.

4.1. PowerWorld

A detailed time-domain electric power system optimal powerflow model. It can be used to model both planning and operational issues on the western interconnection. It contains model elements for transmission network components, generating units, loads and compensation devices. PowerWorld can solve both full AC and decoupled network models, dispatch generation in user-defined modes by area, and perform optimal powerflow dispatch.

4.2. GridView

A production cost model optimized using Linear Programming where dispatch is done with an integrated powerflow representation of the transmission system (decoupled or linearized network model) and interconnected loads and generation to capture transmission system limits within the model.

4.3. Global Energy ProSym

This production cost model uses a "transportation" model of the transmission system to optimize use of the system and, can be used to simulate contract path scheduling between control areas. The model results can be sent to PowerWorld for checking actual transmission flows and limits.

4.4. GE MAPS

The GE MAPS production cost model is optimized using Linear Programming where dispatch is done with an integrated powerflow representation (a Decoupled or linearized) to capture transmission system limits within the model.

5. Modeling Assumptions and Detailed Results

In each case, a range of assumptions were used to generate ranges of probable results. Specifically, assumptions that produced high, medium and low benefit estimates were developed for both a 4 consolidated control area scenarios (4 CCA) and a 10 consolidated control area scenario (10 CCA)). This approach allows the reader to evaluate certain assumptions and the associated results. Furthermore, this “menu” approach enables the reader to assemble his/her own perspective on what category(s) or levels of savings are probable or achievable by Grid West.

5.1. Contingency Reserves (Spinning and Supplemental)

The Northwest Power Pool has a reserve sharing arrangement in place, however, that arrangement is not used in a manner that results in a regional, least-cost solution. Instead, the reserve sharing arrangement is used so that each control area is able to reduce its reserve requirement but each control area must meet that requirement with its own resources. By consolidating control areas, both reserve commitments and costs should be less, i.e. the reserve requirement should be met in a least-cost fashion having access to all resources associated with a number of control areas.

In the past, these benefits have been estimated by Tabors Caramanis and Associates (TCA) for the RTO West Stage 2 Cost/Benefit analysis and more recently by Henwood Energy Services study (commissioned by Snohomish PUD) using their MARKETSYM model. TCA estimated contingency reserve benefits of $150 million/year while Henwood estimated benefits of $73 million/year for the Grid West region. The Grid West region is treated as equivalent to the 10 control area scenario. The benefits calculated for the 4 control area scenario reflect a prorated portion of the total benefits (based upon energy loads).

High: The results produced by Henwood Energy Services.

Medium: Reduce the “High” level of benefits to 75%.

Low: Reduce the “High” level of benefits to 50%.

Grid West Policy: These savings will be achieved along with consolidation of control areas because contingency reserves can be voluntarily offered into a day-ahead market. In addition, the Grid West model provides opportunities for entities outside of the consolidated control area who wish to voluntarily offer reserves into the Grid West consolidated control area market, however, the benefits that could accrue to those outside of the CCA are not considered in this analysis. As a single control area operator with established physical and contractual arrangements with generators that voluntarily offer provisions of these services, Grid West would be uniquely capable of offering contingency reserves.

Recommendations for Further Analysis: Simulation of optimized unit commitment under the Grid West consolidated control area model versus separate autonomous control areas.

5.2. Regulating Reserves

Benefits accrue when regulating reserve requirements are pooled and the magnitude or expected variation in load is reduced, resulting in a reduced need for regulating reserves. Benefits also accrue with the development of a market for regulating reserves because the most economic generation can be selected to provide the reserve requirements. At this point, the assessment of benefits has been limited to quantifying the benefits of pooling and the resulting reduction of the amount of regulation needed.

Studies prepared by BPA staff (2000 and 2005) have evaluated the actual variation in loads for BPA, PacifiCorp and Idaho Power for 3 years and 4 seasons. The reported benefits are based on the instantaneous load deviations from a 60-minute rolling average load which assumes the present state with no in-operating-hour load following market.[25] The quantity of capacity savings varies, depending in part upon the treatment of savings that result from the assessment and suitable application of relaxed control allowed under NERC's Control Performance Standard (CPS) that may allow for reduced requirements for regulation reserves. In this assessment, the value of avoided capacity reserve requirements is assumed to vary between $4 – 6/kW per month, an estimate of a market value of capacity in the PNW and California.

High: The benefits for the 4 control area scenario indicate an estimated savings of 141 MW which includes 32 MW of savings as a result of adopting relaxed control. The benefits for the 10 control area scenario indicates savings of 364 MW which includes 69 MW of savings as a result of adopting relaxed control. Capacity savings were valued at $6/kW/month.

Medium: The benefits for the 4 control area scenario includes savings of 109 MW without any savings resulting from relaxed. The benefits for the 10 control area

[25] BPA used 10 second area load data from telemetry measurements for this analysis.

scenario include savings of 295 MW without any savings resulting from relaxed control. Capacity savings were valued at $6/kW per month.

Low: The savings are the same as described in the Medium case but valued at $4/kW per month.

Grid West Policy: The Grid West model allows for voluntary control area consolidation and regulation reserves can be pooled among those who consolidate. In addition, regulating reserves can be voluntarily offered to the Grid West consolidated control area, however the benefits that could accrue to those outside of the CCA are not considered in this analysis. These savings are unique to Grid West because pooling regulating reserves requires creation of a single control area that is capable of executing tie-line bias control in a hierarchical manner over the control areas consolidated within it.

Recommendations for Further Analysis:

- Current analysis (2005) has not fully modeled the frequency bias component of tie-line bias control under CPS1.
- Incentives for frequency responsive reserves could be implemented by Grid West for both supply and demand-side resources.
- A more thorough study of the market value of capacity should be conducted.
- Explore methods to minimize costs for capacity used for regulation.

5.3. Redispatch Efficiencies

Presently, there are eighteen (18) or so individual control areas in the Pacific Northwest. Schedules between control areas are determined for and locked-in prior to each operating hour; these schedules are based on the control area operator's expectation of load levels and system conditions that are likely in the upcoming operating hour. These schedules reflect the operator's treatment of numerous scheduling rules, requirements and practices that are required between control areas in order to ensure reliable, economic and coordinated operation. They include operating margins and the operator's understanding of physical transmission system flowgate limitations. Schedules, in the pre-schedule time period, are required so that net scheduled interchange can be calculated for each control area, checked-out with other interconnected control areas and, entered into their respective Automatic Generation Control (AGC) systems. AGC holds the net scheduled interchange constant during the operating hour while internal generation available to the operator's control is adjusted to meet the inevitable load fluctuations and other system changes within the control area.

Schedules between control areas have embedded in them the following:

- Power and transmission contracts rights, interpretation and use
- Contract Path Point-to-Point type 888 Tariff Schedules
- NERC, WECC, NWPP and other schedule rules
- Bi-lateral energy trades
- Capacity margins (e.g., Capacity Benefit Margin, Transmission Reserve Margin)
- Transmission rights held for flexibility and for hedging outage performance
- WSPP bilateral wholesale power products
- Treatment of load forecast error and risk
- Planned maintenance
- Unit Commitment plans
- Pricing of transmission
- Reserves
- Treatment of weather forecasts and other external factors
- Assumptions of other operational conditions, e.g., loopflow (inadvertent flows)

When control areas are consolidated into a larger, single control area, interchange schedules between the consolidated areas are no longer required during operations, and the operator has much more flexibility along with a larger combined generation pool than can be used to meet the aggregate control area load and system change requirements.[26] Today, system generation is scheduled between control areas typically using point-to-point contract path service so that schedule amounts are locked in for the operating hour at pre-schedule in accordance with all of the above rules and considerations. In the Grid West model, generation within the control areas that consolidate can be voluntarily bid into the Grid West re-dispatch market and can be re-adjusted and balanced without pre-schedule scheduling limitations. This allows for more efficient use of the transmission within the control area as well as more efficient use of the combined generating resources.

To estimate the benefits of control area consolidation resulting from this effect, BPA, PacifiCorp and Idaho Power Company initiated a study under the Impact Analysis Work Group of the Consolidated Control Area Study Group and collaborated on the assumptions used, techniques, and results. This study used the PowerWorld Optimal Powerflow model, WECC transmission and system data, SSG-WI, RMATS and member generation and product cost/price data and, WECC operating case schedules. WECC operating case schedules were used

[26] While area-to-area interchange schedules are not required for consolidating areas, a contractual settlement for actual dispatch will be required.

for six representative conditions from which operation over a year could be extrapolated. The WECC operating cases were used because time did not permit development of an alternative set of complete schedules between the control areas in the western interconnection. Furthermore, the WECC operating cases are developed and coordinated by the WECC Area Coordinator process to represent the best estimate of typical schedules that are likely for the upcoming operating seasons and conditions.

PowerWorld time-domain simulations were used to calculate production costs that occur during real-time balancing (which occurs in the operating hour as displayed below). In the cases developed for the Grid West studies, the model was designed to hold all pre-scheduled net interchange between control areas constant between the base and change cases. Within each area, for both the base and change cases, load and net scheduled interchange are supplied by WECC along with the unit commitment status, i.e., those generators that are scheduled to be on-line in the WECC base cases.

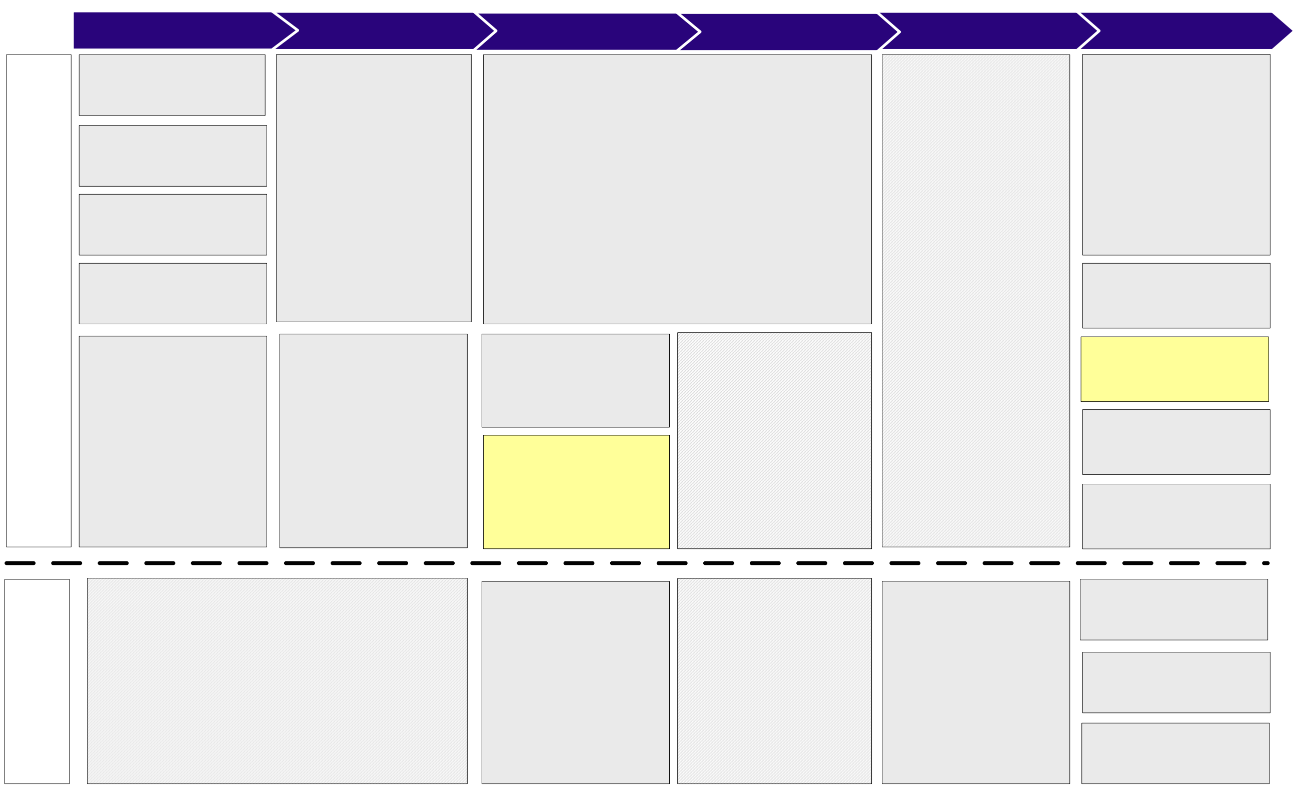

Figure 1. Functional Framework for Grid West (Grid West TSLG, RRG Technical Seminar presentation. November 1, 2004 update. Slide 23.)

As shown in Figure 1, in the Grid West Market and Operational Design, reconfiguration and scheduling occur prior to the real-time operating hour. Surplus capacity offered into the real-time energy market provides Grid West with the opportunity to further minimize operating costs after the end of the scheduling period where unit commitment occurs. The PowerWorld simulations are designed to model the optimization process that occurs during real-time operations and do not capture additional benefits that result from bilateral transactions and unit commitments that are established prior to the operating hour. Those schedules are separate, fixed scheduled interchange inputs in the PowerWorld model and the associated MW balances cancel in the difference case.

The savings are measured by comparing production costs associated with a baseline (without consolidation) and “change cases” that assume control area consolidation. The base case dispatch reflects the optimal power flow (OPF) objective that would occur with existing separate, autonomous control areas performing system control functions, essentially as is done today.[27] The Grid West “change cases” are characterized by moving selected separate control areas into single, consolidated control areas (a 4 control area consolidation and a 10 control area consolidation) that balances energy using a single, OPF objective. Production costs were calculated using five WECC (Western Electricity Coordinating Council) operating and one disturbance power flow cases. These WECC cases are developed to reflect “typical” system operations (load pattern, generation pattern, schedules) for specific seasonal load conditions or, in the case of an outage report, the actual system operation at a point in time. Spring cases were also used for autumn seasonal simulations. Generating unit cost curves were derived from WECC data for the SSG-WI fuel cost data sets as input for determining least cost dispatch in “with” and “without” consolidation scenarios.

The first change case simulation of consolidated control area operations was conducted by combining 4 existing control areas into a single area (“4 CCA”). The second simulation of consolidated control area operations was conducted by combining 10 existing control areas into a single area (“10 CCA”).[28]

Results for eight different periods were calculated i.e., heavy-load-hour (HLH) Spring, Summer, Autumn and Winter seasons and, light-load-hour (LLH) Spring, Summer, Autumn and Winter seasons. For the high estimate, the powerflow

[27] Optimal powerflow (OPF) models, solve economic dispatch of generation sufficient to meet system and load requirements while maintaining all system elements within prescribed operating limits.

[28] The 4 CCA is composed of BPA, Idaho Power Company and PacifiCorp’s East and West control areas. The 10 CCA is composed of the 4 CCA control areas and Avista, British Columbia Transmission Corporation, NorthWestern Energy, Portland General Electric, Puget Sound Energy and Sierra Pacific.

case results—reported in dollars per hour—were applied to the number of hours occurring for each of the eight seasonal load periods and corresponding price frequency, adjusted for leap year.

The extrapolation of limited numbers of simulated operating states to a full year is a standard modeling method, for example, load duration curve models use this method. While having more simulated states may improve overall accuracy, the WECC co-ordination process only produces a limited number of operating cases each year. The resulting savings were viewed as indicative dollar savings for the hours of each time period.

The sensitivity of the resulting dispatch efficiencies to the price (opportunity cost) of surplus hydroelectric generation was tested. Five different cases were run: $20/MW-hour, $30/MW-hour; $40/MW-hour; $50/MW-hour; and, $65/MW-hour. Using the results of these cases, three levels of benefits (High/Medium/Low) were derived for both a 4 control area scenario and a 10 control area scenario:

High: The benefit for each season and load level that assumed that hydroelectric generation was dispatched at a price set equal to the weighted average index price at the Mid-C (for each of the eight study periods) during the 2003-2004 period. For the 4 consolidated areas, the estimated production cost savings are $61 million per year. For the 10 consolidated control areas the estimated production cost savings are $412 million per year.[29]

Medium: Assume that a single, seasonal average Dow Jones Mid-C index price was used to price the hydroelectric generating units in each seasonal case.

Low: Assume the lowest level of benefit for the particular season and load levels calculated using the 5 different prices for hydroelectric generation noted above.

Grid West Policy: These savings are estimated to be possible with consolidation of control areas and creating the real-time balancing market. In addition, the Grid

[29] The low-high range, $30 million - $412 million per year, reflects a range of savings that is equal to 0.8% - 5.3% of power costs, assuming a power cost of $30/MWh. These calculations relied upon load data provided by the Northwest Power Pool and adjusted to reflect the 4 Control Area consolidation or the entire Grid West footprint.

- $30 million in relationship to an annual Consolidated Control Area load of 123,328,390 MW-hour (multiplied by $30/MWh) or,
- $30 million/$3.7Billion in power annual costs = 0.8%
- $412 million in relationship to an annual Grid West energy load of 258,454,840 MW-hour (multiplied by $30/MW-hour) or,
- $412 million/$7.7 Billion in annual power costs = 5.3%

West model provides opportunities for entities outside of the consolidated control area who wish to voluntarily offer resources into the balancing market, however, the benefits that could accrue to those outside of the CCA are not considered in this analysis. These savings are unique to Grid West because secure, optimal dispatch cannot be easily accomplished in real-time through bilateral redispatch. The single, consolidated control area could accept offers from many different generating and demand responsive resources to select the most economical dispatch under constrained operating conditions.

Recommendations for Further Analysis:

- The current analysis uses eight representative seasonal power flow cases [includes a HLH (on-peak) and LLH (off-peak) case for each season] to estimate annual production cost savings. Additional granularity in the study cases could provide a broader selection of time periods and associated load and resource characteristics for inclusion. For example, integration of wind energy resources on a dynamic basis could be modeled in the time domain simulation.
- Representative generating unit cost curves could be further refined and calibrated with prices on a zonal basis.
- Further analysis using PowerWorld coupled with Energy2020, in order to refine the linkage between pre-schedule and real-time operations.[30]

5.4. Bulk Electric System Reliability: Cascading Disturbances

During the past ten years, two major Bulk Electric System disturbances and perhaps one-dozen WECC reportable disturbances have occurred in the states and provinces within the Grid West footprint. Benefits that could result from avoiding cascading disturbances in the Bulk Electric System[31] were derived from the 2004 Gross (Domestic and Provincial) Product for the Grid West footprint.[32] Based upon US Census Bureau wage and earning data, it was assumed that 85% of total production occurs during weekdays and therefore, 15% occurs during weekends. The existence of Grid West could enable improved bulk electric system reliability ranging from the avoidance of one (1) additional cascading disturbance every 20 years to avoidance of 1 additional cascading

[30] There has been significant discussion about: (1) the use of the PowerWorld results (four seasons and two-diurnal periods for each) to represent seasonal conditions and in turn, to represent conditions over a year; and, (2) the operating prices (or opportunity costs) that have been used for dispatching hydroelectric generation.

[31] See NERC glossary for definition of Bulk Electric System.

[32] US Bureau of Economic Analysis and Gross Provincial Product data for Montana, Wyoming, Idaho, Utah, Oregon, Washington and British Columbia indicates $761.2 billion Gross Domestic/Provincial Product for 2004.

disturbance of 1 productive day every 15 years. A cascading disturbance is assumed to result in 50% loss of GDP (the remaining 50% is assumed to be recovered or protected by back-up generation).[33]

High: If an additional cascading disturbance were avoided every 15 years, the annualized benefit would be $83 million/year, assuming that the disturbance occurred on a weekday (or $36 million/year, assuming that the disturbance occurred on a weekend).

Medium: This reflects an average between the High and Low cases.

Low: If an additional cascading disturbance were avoided every 20 years, the annualized benefit would be $61 million/year, assuming that the disturbance occurred on a weekday (or $27 million/year, assuming that the disturbance occurred on a weekend).

Grid West Policy: The Grid West proposal has Basic Features that support Bulk Electric System reliability functions as follows:

- a system-wide reliability authority which will enable direct redispatch of generation for reliability, rather than the current practice of relying upon negotiated transmission schedule curtailment;
- a single, system-wide scheduling entity with a day-ahead visibility of transmission system usage and planned generation dispatch;
- a system-wide, "one-utility" organization responsible for system contingency planning;
- a system-wide planning responsibility for reliability supported by "planning backstop" authority;
- price transparency in real-time balancing markets that better informs industry responses to real-time redispatch requests; and,
- a single, standardized method for outage planning and coordination that is different from what is currently in place.

Recommendations for Further Analysis: to be determined.

5.5. Power Delivery System Reliability – Momentary/Sustained Outages

[33] The estimate used for a cascading disturbance include only the disturbance impacts for the same region in which the disturbance occurs. However, impacts are typically more widespread. For example, in 1996, the disturbances that were caused in the Pacific Northwest affected millions of customers in California. Similarly, the 2003 disturbance in the Midwestern U. S. was not limited to the First Energy system.

Benefits to consumers would also accrue from reducing the frequency and duration of more common shorter, and less widespread outages (more than 5 minutes to less than 12 hours and typically within a utility's footprint). These benefits are additive to the cascading outage benefit figure provided in the previous section. The estimates in this report draw on the framework developed by Lawrence Berkeley National Laboratory (LBL) on the value of avoided outages to customers, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers," September 2004. The LBL study developed a detailed framework for estimating cost of Momentary and Sustained outages for residential, Small C&I and Large C&I. It used a meta-database of thousands of surveys conducted by 24 utility valuation studies, conducted between 1989-2002 (using EPRI standards). The study developed a detail analytical framework using results of surveys of customer willingness to pay for outages, utility average outage data, national and regional data on industry, employees, wages, etc. The study yielded a regional and national estimate of the current cost of outages (distributional and transmission) in the United States.

Results for the Pacific Northwest region were pro-rated to a per-MW-hour served basis, derated to express the ratio of distribution to transmission-related outages, then applied to the loads for PacifiCorp, Idaho and BPA for the 4 consolidated control area basis.

See appendix file Customer's_cost_for_Sustained_Outages.doc for a detailed description of this analysis. ***The 10 consolidated control area basis were the same. Applying load to the average cost of outage per kWh of load.***

High: Assume that 10% of total interruptions are transmission-caused; the cost of interruptions was weighted by the composition of residential/commercial/ industrial consumption particular to the Pacific Northwest (separately for the 4 control area scenario and for the 10 control area scenario); the Grid West model will enable the transmission system to be at least 20% more reliable than it is today. The "high" value is based upon the average estimated outage cost plus one standard deviation of the key variables which translates into 70% higher than the average value. For the 4 consolidated areas, the estimated savings is $98 million/year. For the 10 consolidated areas, the estimated savings is $231 million/year.[34]

Medium: The average estimated outage cost which is based same assumptions on the percent contribution of the transmission outages to total outages (10%) and based on LBL study for customer cost of outage using region specific data

[34] Arguably, the 10 consolidated area estimate is also applicable to the 4 consolidated control area estimate, assuming that Grid West is the NERC/WECC designated Reliability Authority for the entire Grid West footprint.

for sustained and momentary interruptions. For the Pacific Northwest, the estimated transmission related outages are $280 million/year. We assumed that 20% of this cost can be saved through Grid West operations. For the 4 consolidated areas, the estimated savings is $58 million/year. For the 10 consolidated areas, the estimated savings is $136 million/year.

Low: The average estimated outage cost minus one standard deviation of the key variables which translates into 70% lower than average. For the 4 consolidated areas, the estimated savings is $17 million/year. For the 10 consolidated areas, the estimated savings is $41 million/year.

Grid West Policy: The Grid West proposal is expected to minimize the frequency and duration of interruptions by providing the operator with: (1) better knowledge and detection of bulk power system operating states; (2) an improved ability to control facilities that monitor and control system operation; (3) improved communication facilities; (4) better trained personnel able to react properly to wide-area system events and prepare restoration plans[35]; (5) accurate prediction of near-term operating conditions; and, (6) optimum use of transmission maintenance crews and resources; and, (7) use of comprehensive "best practices" planning, operating, and maintenance criteria aimed at developing and operating a reliable and robust power system.

Recommendations for Further Analysis: Additional detail on participants SAIDI and SAIFI information and continued research on the value of outages to Pacific Northwest customers.

5.6. Rate and Transactional Pancakes

Rate pancaking refers to the practice of recovering the embedded costs of transmission on a control area by control area basis. This practice can unnecessarily increase the cost of delivered power by creating the appearance of incremental costs where there are virtually none (transmission investments to carry load have already been made). This, in turn, can bias the system against lower cost resources whose output must cross multiple control area boundaries, but whose delivery causes no actual transmission costs.

In addition to transmission rate pancaking, there is the potential problem of transactional pancaking. This occurs when buyers of transmission must contact multiple transmission owners to coordinate the delivery of power. The time requirements, information barriers, and administrative burdens created by this

[35] Esselman, Francis and James Reilly. "Averting Grid Collapse: System Control and Restoration in Emergency Conditions." IEEE Power and Energy Magazine. July/August 2004.

practice may limit efficient trade across multiple control areas. Additional information about rate and transactional pancaking is contained in the RR workgroup whitepaper contained in the appendices (06_Pancaking-2.doc).

Results are shown for prior studies performed by TCA and Henwood (some of which were widely reviewed and debated) and additional studies prepared for this report. Additional studies were performed using the GridView model. GridView is a flow-based production cost model which used SSG-WI production cost data for the western interconnection. The models each computed the difference in fuel and operating costs for the western interconnection between a base case and change case. The base case assumes that certain defined transactions face wheeling charges. The change case assumes that the Grid West pricing method would remove most of these pricing pancakes. The models differ on the amount of base and change case price pancakes.

In the GridView model the base case has wheeling pancake charges between control areas representing typical point-to-point type charges of tradable rights that could be re-sold by the holder. Transactions within a single control area are not assessed a wheeling charge in either the base or change cases (hence transactions totally within the BPA control area move without charge). The change case removes wheeling charges for all area-to-area transactions in the Grid West footprint.

High: $61 million/year. The estimate is based on the TCA study with adjustments proposed by the "TCA Critique" paper.

Medium: $20 million/year. Based on the average results from GridView model runs. GridView, developed by ABB, was used to estimate the benefits that could result from eliminating marginal wheeling charges in the Grid West region, assuming different control options and usability of Total Transmission Capability (TTC) levels.

Low: $3 million/year. Based on estimates derived in the Henwood Energy Services study (commissioned by Snohomish PUD). This study assumed that schedules through BPA were not pancaked (because regional transactions were assumed to be sheltered under fixed-cost contracts), schedules that have to go around BPA are considered to be pancaked.[36]

[36] Henwood Energy Service's estimate should be re-evaluated to determine whether the network topology used for their analysis is consistent with both current and consolidated area studies.

Grid West Policy: The Grid West model assumes that rate pancakes are eliminated for new use through Real-Time Balancing Service and Reconfiguration Service.

Segregation of Benefits:
Significant efforts were taken to ensure that the benefits associated with eliminating rate pancaking were not also measured as benefits in the PowerWorld Redispatch Efficiencies simulations described in a prior section. The Redispatch Efficiency PowerWorld models include fixed area-to-area interchange schedules that are identical in both the base cases (meaning no control area consolidation) and the change cases (meaning 4 CCA and 10 CCA scenarios). These transactions which may or may not include wheeling charges, net out when the difference between base and change cases are computed. Referring to Figure 1 above, the pancaking impacts being measured in GridView are limited to those that would occur during preschedule periods prior to the operating hour.

The GE MAPS, ABB GridView, and Global Energy's ProSym models all fix the hydro dispatch and establish an optimal thermal dispatch for the base and Grid West cases. The resulting dispatch is representative of what would occur through the preschedule period, and which is assumed to be the same for the entire operating hour. In contrast, PowerWorld takes typical, perhaps sub-optimal, prescheduled commitments and simulates the balancing market response of the control areas during the operating hour after the preschedule period ends. PowerWorld will not change interchange schedules or unit commitments made prior to the operating hour, but may move hydroelectric generation depending on hydro opportunity costs or thermal generation according to OPF economic dispatch.

Recommendations for Further Analysis:

- Ideally one would combine the preschedule and unit commitment study methods (e.g. GridView) with a real-time simulation (e.g. PowerWorld) to measure both rate pancake impacts and the resulting real-time energy balancing effects.
- More detailed examination of existing transmission contracts would provide guidance on the degree to which transmission service rate sheltering mitigates intra-area charges. Survey responses indicated that, in spite of sheltering, L-shaped schedules within one or more control areas are often used to circumvent transmission constraints, in spite of pancaked charges.

5.7. Reconfiguration and Increased Transmission Utilization

Benefits derive from increased access to existing transmission capacity as a result of more liquid and transparent transmission rights markets, through the use of flow-based injection/withdrawal scheduling practices, and through the centralization and optimization of the rights acquisition process. The GridView analysis estimate in this report is a sensitivity based assumption – it looks at what the benefits would be if the reconfiguration market yields 3%, 5%, and 10% more available flowgate capacity (AFC).[37] GridView was run to estimate the least cost dispatch to meet loads over 1 year in the Grid West footprint. Production cost benefits were derived from comparing a base case that assumed that 90% of TTC would be available to support transactions. This base case was compared with runs that increased TTC to 93%, 95% and 100%. The measured benefit results from the less expensive generation dispatch that occurs with greater amounts of transmission capability.

It is important to note that, for consolidators, some of these benefits may have already been measured with the PowerWorld balancing market / CCA work discussed in Section 5.3 Redispatch Efficiencies. Overlap between the two estimates will need to be evaluated in subsequent studies. An alternative method of analysis using PowerWorld is described in the Appendix which accounts for this overlap (see PowerWorld_Alt_RCS_and_Incr_TX_Util.doc). It is noteworthy that this alternative method produced comparable estimates of benefits, $13 million - $41 million/year.

Estimates:
High: $52 million annually – based on runs looking at production cost benefits of a 10% increase in AFC.

Medium: $30 million annually – based on runs looking at production cost benefits of a 5% increase in AFC.

Low: $18 million annually – attempting to capture benefits of 3% increase in AFC by interpolating from the 5% estimate (assuming $6 million in benefits per 1% increase in AFC- $30 million for 5% or $6 million per percent).

[37] According to a TCA survey of Northwest utilities, "..a significant number of utilities reserve capacity in order to implement cross control area scheduling today, in a similar manner to the Transmission Reserve Margin (TRM) and Capacity Benefit Margin (CBM) practices in eastern markets. Most Northwest utilities reserve a portion of their transmission capability." TCA concludes that "these reservations can be anywhere from 5% to 10% of transmission system capability". See "Response to the RTO West Benefit Cost Study Critique", April 19, 2002. The Energy 2020 model has also included a range of increased transmission capability of 3%, 5% and 10%. See BPA's Energy2020/PowerWorld Analysis Update slide 6.

Grid West Policy:
Grid West has a broader view of the system. Grid West will act as the gatekeeper on the region's transmission capacity meaning that it will determine the availability of transmission capability, based upon a regional determination of operational limitations. In addition, Grid West will administer a centralized, flow-based RCS as well as administer sales of AFC.

Recommendations for Further Analysis:

- Reconfiguration permits all parties to obtain value for their transmission rights, including surpluses above their own requirements. In the optimal case, the system would be dispatched to minimize operating costs within the entire Grid West region as though it were a single control area. Evaluating the efficiency of a single control area operation may serve as a surrogate for the impact of a fully liquid reconfiguration service market. This was the approach in the alternative analysis and more work will be done to determine the market design and interplay between rights held in pre-schedule and transmission efficiency in real time.
- Energy2020 may be able to measure the compounded effects of reconfiguration service, pancake elimination and optimal use of transmission.

6. Survey Results

The RR workgroup relied upon the problems and opportunities identified by the RRG that to focus its efforts on estimating potential benefits of Grid West.[38] The problems and opportunities provided the starting point for a survey developed by the RR workgroup that was used to gather detail and data from market participants including Major Transmitting Utilities, Transmission Dependent Utilities, Marketers, Generators and other regional stakeholders.[39] Out of 33 potential respondents, 30 responses were received, resulting in a 91% response rate.

Survey participants responded to each set of 37 questions. However, in each category, the responses reflected a wide range of viewpoints. The responses were not always clearly correlated with the character of the responding entity, e.g., Major Transmitting Utility, Transmission-dependent Utility, etc. In fact, often the responses were affected by the respondent's geographic location (e.g., located in BPA's service territory or on the fringe of the Grid West footprint), its business scope (e.g., vertically-integrated entity, marketer, transmission provider, load-serving entity, etc.) and, the entity's adequacy in terms of generating resources and transmission capacity.[40]

A summary of the survey responses is found in the appendix to this report (RRSurvey_WhitepaperSupport_051905.doc).

The survey focused on seven categories. Below are an explanation of the purpose of each of these categories and a summary of the responses.

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38 The RRG document summarizing the transmission problems and opportunities the RRG identified though its work in 2003. This summary was not intended to be a consensus statement but rather a collection of statements that reflected a broad canvassing of regional stakeholders. This document is available on the Grid West Website at: www.gridwest.org/Doc/Reference_Document_Sept52003.pdf.

39 The pool of survey respondents included: Avista, BPA-TBL, BPA-PBL, BCTC, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Sierra-Pacific, Calpine, Clark Public Utilities, Deseret, Eugene Water and Electric Board, Industrial Customers of Northwest Utilities, Northwest Independent Power Producers Coalition, Northwest Requirements Utilities, Pacific Northwest Generating Company, PPL-Montana, Pacific Power Marketing, Powerex, Power Resources Managers, the Public Generating Pool, the Public Power Council, Seattle City Light, Snohomish PUD, Tacoma Power, Tractabel, TransAlta, Utah Associated Municipal Power Systems, and the Renewable Northwest Project.

40 A number of survey respondents produced quantitative evidence or analysis of the problems they identified. If development of Grid West continues after Decision Point 2, further analysis will be done.

6.1. Production Cost

This category was used to probe the extent to which the cost of producing power as well as resource development is impacted by rate pancakes, dispatch inefficiencies and actual or perceived congestion.

The survey responses indicated that power customers of BPA and utilities that use only the BPA Network segment in order to serve load do not perceive any problems; the BPA Network segment is rarely constrained, although the Interties are curtailed in order to manage congestion on the BPA Network. On the other hand, marketers, resource developers and utilities with load growth see rate pancakes as problematic: they explained that rate pancakes cause inefficient dispatch because the cost of multiple wheels exceed the differential between high and low operating costs; multiple scheduling and reservation procedures are not in sync; and, pancakes impact resource planning and development decisions by favoring resources located close to load and discouraging fuel diversity.

Under the Grid West market design, Grid West will schedule all transactions and therefore, administrative pancakes will be significantly reduced or eliminated. In addition, the pricing proposal reduces or eliminates rate pancakes for all new transactions.

6.2. Transmission System Operations

This category was used to probe the extent to which there are perceived inefficiencies with operating the transmission system including coordination of operation and maintenance schedules, operating the ancillary services markets, and implementing dispatch orders.

The survey responses indicated that some have not had any problems with barriers to entry into the ancillary services markets or dispatch orders. On the other hand, many indicated that they have experienced: barriers to entry to ancillary services markets due to technical requirements, flexibility limits and inconsistent business practices/systems; problems with outage scheduling processes due to lack of consideration being given to market conditions; instances where dispatch orders were requested without any impact on congestion; and, an inability to recover from curtailments forcing a schedule to be “taken out” or “booked out.”

Grid West, as an independent, membership corporation is expected to oversee and administer in a non-discriminatory manner ancillary service markets for the consolidated control area (and entities outside of the CCA that are participating in those markets) as well as administer scheduling procedures and coordinate outage and maintenance schedules. In keeping with its Market and Operational Design, Grid West will rely upon generation and demand-side resources that are voluntarily offered to support its operational functions, e.g., regional and consolidated control area services.

6.3. System Capability and Scope

This category was used to probe the extent to which there are concerns about how transmission system capability is impacted by reliability policies, parallel flows (inadvertent flows caused by contract path scheduling), remedial action schemes, determinations of available transfer capability and interface systems with customers (e.g., OASIS postings, reservation and scheduling practices, etc.).

The survey responses indicated that some were not aware of any problems with ATC calculations. On the other hand, a number of responses indicated that often times, transmission providers inconsistently apply reliability and capacity benefit margins thus resulting in inconsistent determinations of ATC at seams resulting in what they considered as unnecessary and ineffective curtailments; unscheduled flows cause curtailments, dispatch inefficiencies and voltage instability due to contract path scheduling procedures; inefficient scheduling and reservation procedures cause lost opportunities; and, problems arising from conflicting standards and non-comparable compensation regarding RAS.

Grid West will be the reliability authority for the Grid West footprint. In addition, the use and availability of transmission capacity will be determined on a flow-basis which is expected to free-up capacity by calculating AFC based upon operational limits not both contract path constraints and operational limits (and accounting for inadvertent flows). Finally, Grid West will be the gate-keeper of transmission capacity for the region and will administer a single OASIS using standardized reservation and scheduling practices.

6.4. Existing Transmission Constraints

Both Transmission Providers and Transmission Customers were asked to respond to whether transmission path limitations (flowgate limits) impact access, the extent to which limitations are experienced, and to what extent real-time curtailments are used to manage constraints.

The survey responses indicated that for some transmission providers, their operations have not been affected by flowgates or posted paths. Other transmission providers reported a proliferation of congestion (path deratings) since 1996 and common use of curtailments in order to manage congestion and necessary due to parallel flows. Transmission customers using the BPA Network reported that they do not see congestion/curtailment as a problem. Marketers, Major Transmitting Utilities and Generators reported that there are 20-30 paths that currently impact desired transactions; that transactions cannot be redirected due to the prevalence of congestion and, that real-time curtailments on the Pacific Intertie are "too numerous to gather".

The Grid West market design will monitor and sell capacity based upon flow. A broader scope of the grid is expected to result in less curtailment and operational improvements, i.e., identification of which schedules are able to relieve constraints. Grid West will implement system-wide "one-utility" planning for expansion (seeking wires and non-wires solutions) with a backstop mechanism for reliability investments.

6.5. Inconsistent Treatment of Generators/Loads

This category was used to probe the extent to which there is non-comparable treatment imposed on suppliers of various ancillary services and remedial action schemes.

The survey responses indicated that some had no examples of non-comparable treatment with ancillary services markets or Remedial Action Schemes (RAS). Others reported non-comparable treatment in terms of compensation for reactive, RAS, operating reserves or ability to offer into these markets.

Grid West is expected to oversee and administer in a non-discriminatory manner, ancillary service markets for the consolidated control area (and entities outside of the consolidated control area that are participating in those markets). It is anticipated that Grid West will also administer standardized procedures for RAS.

6.6. Tariff and Business Practice Confusion

This category was used to probe the extent to which administrative inefficiencies result from confusion and conflicts involving tariffs, business practices, reservation and scheduling procedures and timetables, capacity determinations and queuing procedures.

The survey responses indicated that Transmission Dependent Utilities have not been affected by rate and administrative pancakes and others have not experienced delays in System Impact and Facilities studies. Others reported serious concerns about the lack of OASIS systems in the region; the lack of conformity of tagging procedures; a lack of adequate services to support intermittent resources; and, significant problems with long-term service queues. In addition, a number of entities reported lodging minor and formal complaints with FERC and engaging in arbitrations under NRTA, WRTA and WECC.

Grid West will administer a single queue which should enable better management of transmission capacity, system impact and facilities studies. Grid West will also administer and post transmission capability on a single OASIS using a single set of business practices and reservation/scheduling procedures.

6.7. Planning and Expansion

This category was used to probe the impact that transmission congestion has on investment decisions (both transmission and generation), the identification of solutions, coordination on planning activities and the allocation of costs and benefits associated with a particular investment decision.

The survey responses indicated that respondents located in areas or relying upon transmission without congestion have not experienced problems. Others that face congestion have experienced dispatch inefficiencies and face problems with developing and integrating new generating sources. Several indicated that due to the lack of a congestion management system that values congestion, schedules are cut or denied in order to maintain reliable operation, costs are internalized and planning is typically limited to an individual control area.

The Grid West market design will monitor and sell capacity on a long-term and short-term basis based upon flow. The RCS market will provide information on the value of transmission which will inform resource dispatch as well as investment decisions for wires, non-wires and resources. The broader scope of the grid is expected to result in less curtailment and operational improvements, i.e., identification of which schedules are able to relieve constraints. Grid West will implement system-wide “one-utility” planning for expansion (seeking wires and non-wires solutions) with a backstop mechanism.

7. Qualitative Elements

7.1. Improved Transmission Planning

Grid West's transmission planning provisions should provide a more transparent and effective planning process than the coordinated, yet fragmented, planning process it will replace. Benefits are expected to accrue due to the system-wide "one utility" planning model for grid expansion that will be adopted by Grid West. This model will be informed by data that indicates the cost of congestion and the value of relieving congestion (with wires and non-wires solutions). Building decision will be supported by Grid West's "planning backstop".

7.2. Construction Deferral

In addition to the estimated production costs savings associated with Grid West's RCS and real-time energy markets (see Sections 5.3 and 5.7), increased utilization of existing transmission and generating facilities could make it possible for utilities to defer construction of generation and transmission capacity. As illustrated by the substantial increases of ATC recently calculated for several previously constrained BPA flowgates as a result of BPA's new flow-based methodology and business practices, at least one planned transmission project has been deferred and additional ATC is now available on several more flowgates to allow bottlenecked generation to be used.[41] The Grid West model will facilitate a much wider application of these types of flow-based scheduling methods, and when combined with the additional efficiencies of markets for re-dispatch and transmission rights, more transmission capacity and opportunities to deliver surplus power and capacity will be available.

Additional ATC could be sold long-term or traded in the RCS. Surplus generating resources could then be offered into ancillary services markets as capacity products, or used to generate and sell economy energy. Qualitatively, a utility, under the coordination of Grid West, would have the opportunity maintain compliance with applicable adequacy and reliability standards by locating sources for capacity products over a broader market. Greater visibility of capacity prices and resource integration feasibility are also expected to improve through Grid West services.

[41] A recent posting on the BPA-TBL Business Practices Forum shows ATC increases between 3% and 18% on eight different constrained paths. See posting at www.transmission.bpa.gov/business/Customer_Forums_and_Feedback/ATC_Methodology/documents/FinalATCComparison.pdf.

The quantitative benefits associated with construction deferral are derived from decreased and delayed capital carrying costs. While the risk-reward work group was not able to identify specific projects attributable to Grid West, it has identified likely examples of construction deferrals that are reasonable and conservative given BPA's experience with their flow-based business practices to date.

Construction benefits in the analysis are based on the time value of deferring capital expenditures and carrying charges. These capacity benefits are additive with benefits associated with energy and production cost savings. Additionally, the availability of reserve, re-dispatch, and balancing markets that more easily allow demand side management (DSM) resources to participate can also facilitate construction deferral. These will be addressed separately in the next section.

The conservative estimates of the capital carrying costs savings from this type of construction deferral ranges from $4 million to $20 million per year within the Grid West region. Representative estimates of transmission and generation deferral benefits are shown in Appendix 9.6.

Grid West Policy:

- Grid West will optimize use of existing transmission facilities through its real-time energy market and RCS.
- Grid West will administer ancillary services markets that can be accessed by all market participants for selling surplus capacity.
- Grid West will administer a real-time energy market that can be access by all market participants for selling surplus energy from capacity freed up by reserve pooling by Grid West.

Recommendations for Further Analysis:

- Identify transmission projects that have been stalled for structural and financial reasons.
- Enumerate options considered as alternatives to specific projects.
- Describe Grid West features that affect either transmission project schedule or consideration of non-wires options.
- Analysis using expansion models such as Energy 2020 need to be completed for 5, 10, and 20 year horizons to demonstrate the overlap between short-term production cost savings and long term capacity expansion deferral.

7.3. Conservation and Demand Side Management

As mentioned above, the availability of reserve, re-dispatch, balancing, and RCS markets more easily allow demand-side management (DSM) resources to participate in regional supply. These efforts can also facilitate construction deferral and efficiency savings in addition to the direct energy savings of conservation. These savings stem from the dispatchability and location of possible DSM and its use in the aforementioned product markets.

Ease of entrance into the Grid West markets and the increased price visibility facilitated by Grid West markets will allow developers to fully assess the value of non-wires solutions and dispatchable conservation. Controllable DSM and conservation can be bid into the reserve, balancing and re-dispatch markets. Transmission rights not needed could be auctioned in the RCS providing incentives for load aggregators to develop additional conservation and DSM. Long-term predictable and dispatchable DSM could be included in the combined Grid West planning process.

Documents in Appendix 9.7, discuss results from SSG-WI studies considering the impact of demand-side measures on load growth and how it affects transmission and distribution requirements. While the Grid West market design is not yet detailed enough to make a complete estimate of the benefits from DSM and conservation and because of Decision Point 2 time and modeling limitations, the analysis in this report uses a portion of the savings indicated in the SSG-WI study. Allocating a portion of these saving to the Grid West facilitating market design indicates a range of benefits from non-wires opportunities to be in the range of $1 million to $61 million annually.

Recommendations for Further Analysis: same as previous section

7.4. Load Following

The real-time balancing and re-dispatch market will not only provide for more efficient use of transmission and the combined generation stack on generation control within the consolidated control area and Grid West footprint, it will allow for more economic load following. Load following is the provision of in-operating-hour generation and interchange capability changes needed to meet in-operating-hour load increases or decreases due to daily variations not covered by regulation service. Consolidation of control areas enables the establishment of balancing markets within the operating hour that include a larger selection of generation available to provide load following and regulation than would otherwise be available. This larger selection and opportunity to capture load diversity allows for access to the most economic units to provide both load following and regulation. Time and modeling limitations precluded the RR workgroup from quantifying these benefits.

7.5. Coordinated Generation and Transmission Maintenance

Maintenance outages may have a significant commercial impact on power suppliers, and the economic impact on customers may be reflected in purchased power adjustment charges or increased risk premiums charged to their utility. Generation and transmission outages can cause purchase of replacement power on short-term contracts, and depending on market conditions, significant costs may be incurred. Transmission outages can potentially form a barrier that prevents delivery of low-cost energy to consumers.

Coordinated maintenance scheduling was studied by Henwood in the October 2004 report to Snohomish PUD. The report concluded that the historical pattern of generator maintenance outages was consistent with the optimal schedule produced by their simulations. In a response to Northwest Independent Power Producers Coalition (NIPPC), Henwood stated that "Henwood modeling to date has not evaluated impacts of "improving" coordination of transmission system maintenance."[42] Therefore, no studies to-date have addressed whether coordination of transmission maintenance scheduling is planned to minimize economic impacts on consumers.

Responses to the survey indicated widely divergent views regarding the effectiveness and efficacy of generation and transmission maintenance coordination. While Major Transmitting Utilities (MTUs) generally regarded the existing Northwest Power Pool Coordinated Outage System (COS) procedure as adequate, some generators and marketers contend that the commercial and economic impacts of transmission maintenance outages are not adequately considered. Another common complaint was that transmission providers did not provide adequate justification for reductions in transmission capacity during outages. Subscribers to the BPA-TBL Transmission Capacity E-mail Forum receive a steady stream of concerns about the impacts of maintenance outages on the cost transmission maintenance outages.[43] While it is clear that the region actively discusses the occurrence and scheduling of transmission maintenance outages, the workgroup was unable to identify what methods are used to evaluate the economic impacts of transmission outages on transmission customers or the consumers that they serve.

[42] Letter from Rich Lauckhart, Vice President, Global Energy Decisions, to Robert D. Kahn, Ed.D. December 7, 2004. Response to question 13.

[43] Subscribe to capacity-l-bounces@list.transmission.bpa.gov.

In many cases, outages taken by one utility affect path ratings of another utility. The NWPP COS provides the mechanism for utilities to coordinate the outage event, but the network impacts on other parties are not rigorously analyzed. The workgroup recognizes that outage schedule and production cost information may be commercially sensitive and therefore such analyses may not be possible without an independent party that can study the impacts and develop optimal schedules. Grid West's coordinated outage function should provide a more transparent process than is currently used, and participants will be encouraged to look beyond direct benefits in their own outage plans, encouraging more efficient (with respect to system-wide impacts) outage schedules.

Grid West Policy:

- Grid West will have sufficient data and analytical tools to optimize both generation and transmission outage scheduling.
- As an independent entity, Grid West would not have inherent conflicts of interest or commercial bias in its assessments of maintenance outage schedules.

Recommendations for Further Analysis:

- Historical transmission system outage data should be analyzed to determine whether the resulting coordinated schedule minimized economic costs to the region.
- A comparison between an optimal transmission outage schedule historical outage schedules may provide sufficient bases for a quantified estimate of the benefits associated with this function.

7.6. Market Innovation

Benefits are expected to accrue from technological and strategic innovations made possible by the development of new transmission services and broader market participation in ancillary service markets.[44] The existing baseline in the electric utility industry tends toward traditional solutions without consideration of or adequate incentives for new innovations that are possible with changes to the organizational and service structure of the industry. Some survey respondents believe that utilities will have to innovate or allow for innovation in order to stay in business.

Examples of innovations that Grid West would foster in the near term include:

[44] For the whitepaper report on this topic see appendix file 12_Technological_Innovations-June13.doc

- SmartGrid and Self Healing Grid technologies that provide a demand response which is beneficial to transmission system operations.
- Vehicle-to-Grid (V2G) technologies in which electric vehicles become energy storage devices on the power grid with the ability to regulate load and even deliver power to the grid for short periods.[45]
- Other demand-side measures that are beneficial to operation of the transmission grid.[46]

7.7. Market Monitoring

Grid West would establish a market monitor function that collects and analyzes relevant market information. The market monitor function would be conducted by an independent organization acting as a regional market monitor. It is expected that a market monitor will provide detection, prevention and mitigation of market dysfunction. Because some view market monitoring as a requirement necessary to establishing markets, they view this function as an enabler of other benefits rather than a function that provides additive benefits or cost savings. The argument centers on whether or not a market monitor should be considered a function and benefit associated with Grid West or simply part of an existing state.

A market monitor will help avoid market manipulation and unnecessary price spikes. Grid West's establishment of common, transparent markets for power transactions should uniquely enable the market monitor to identify possible abuses. Further, a grid-wide market monitor should help to avoid inadequate market design, anticompetitive behavior and market abuse.

The potential benefits and impacts of market monitoring in Grid West are described in greater detail in appendix file
08_RRWorkgroup_Whitepapers_MarketMonitoring_Final.doc.

7.8. Dispute Prevention and Resolution

Benefits are expected to accrue to stakeholders in the region as a result of common business practices, common interpretations of tariff terms and conditions, a common transmission service queue, and regionally-vetted outage and maintenance schedules. The extensive regional effort to establish these common elements for the Grid West transmission Market and Operational

45 www.udel.edu/v2g

46 Foley, Tom and Preston Michie. Demand Side Measures And Their Potential Within Grid West. July 11, 2005. See appendix file
Demand_Side_Measures_And_Grid_West_Draft_July_11_2005.doc.

Design is consider by many stakeholders to be a fundamental factor in preventing disputes among parties taking service from Grid West. As a backstop, Article XIII of the Grid West Operational Bylaws provides an alternative dispute resolution process for disputes that may occur under the Operational Bylaws.

8. Unquantified Risk Elements

Potential risks associated with Grid West formation were identified and discussed by the RR workgroup.[47] There is not wide agreement among group members regarding the validity of the risks identified or the measures and policies that may be used to mitigate these risks. Both the risk element and mitigating factors are discussed below.

8.1. Costs of a New Organization

There is a potential risk that the cost of a new organization will be considerable and unmanageable and outweigh any foreseeable benefits. Studies have been conducted showing the cost and seemingly uncontrolled increases in costs in other RTOs and ISOs. There are no guarantees that the estimated costs will be accurate. Dealing with a new organization also creates a perceived risk.

This possibility was considered by Grid West designers and participants. The Grid West features that are expected hedge against this cost risk include:

- The fact that Grid West is developing in stages and is not starting out with an expensive market for financial transmission rights found in most of the existing FERC-approved RTOs.[48]
- The management of FTRs (Financial Transmission Rights) has proven to be a significant cost driver for existing RTOs. Grid West has not adopted FTRs.
- A detailed bottom-up cost estimate is being prepared by the TSLG and The Structure Group. The analysts working on the cost estimate have had the opportunity to learn from existing RTOs and system operators how to accurately estimate and control costs.
- The fact that the Grid West Operational Bylaws contain detailed provisions that require Grid West to: (a) develop its budgets through a member-driven process; and, (b) remain focused on operating cost-effectively.
- The RR workgroup's attempt to quantify benefit estimates are intended to enable direct comparison to cost estimates.
- Just as jurisdictional utility rates are subject to FERC regulation, the Grid West transmission agreements will also be subject to FERC regulation where they can be challenged by customers.

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47 See appendix file Grid_West_risks.doc

48 See http://www.gridwest.com/Doc/TLSG_Update-Report_24Mar2005R.pdf for a comparison between FERC SMD Style RTO features and Grid West Basic Features. Page 21.

- Customers can retain existing transmission service agreements rather than switching to Grid West if they are concerned about dealing with a new organization.

8.2. Uncertainty of the Efficacy of the Planning Process

There is a perceived risk that Grid West could be too transmission-centric in its planning and investment decisions and thereby, increase the potential for gold-plating or overbuilding transmission infrastructure.

- The Grid West planning and expansion model addresses this concern by proposing an economic framework for evaluating transmission investment decisions and cost recovery. Moreover, the Grid West planning process will involve transmission owners, non-transmission owners and federal, state, provincial and tribal agencies to ensure that wires and non-wires alternatives will be considered.
- Grid West will not have an inherent interest in financing transmission assets to increase its rate base, thus mitigating any bias toward transmission or generation construction.
- Grid West will have planning tools that model the entire power system—not just transmission. Powerflow models can accurately simulate the effects of load control, distributed generation, industrial process controls, transmission switching, generation redispatch and many other non-construction solutions to grid planning and operations.

8.3. Potential for Unaccounted for Costs

There is a perceived risk that unanticipated costs can be easily socialized, such as unaccounted for energy, lower than projected revenues, greater than expected construction costs, etc.

- Grid West does not have unaccounted for energy in its model; this has been a problem in California, for example, where the meters were not adequate to track all wholesale and retail transactions thus, resulting in unaccounted for energy, the cost of which was socialized among all users.
- Grid West has attempted to address revenue under-recovery concerns through its pricing proposal.
- The concern about loss reallocations is largely mitigated by the ability of customers to retain their existing contracts.
- Construction cost issues (allocation of costs and benefits) will be vetted in a regional planning forum.

8.4. FERC Engagement (or Non-engagement)

There is a perceived risk that there are no assurances that FERC will be engaged with the Grid West process when it should or dis-engage when it is not needed.

In anticipation of this possibility, some Grid West filing utilities filed with FERC a Petition for a Declaratory Order seeking guidance on the Grid West proposal. The resulting declaratory order, issued July 1, 2005, confirmed, among other things:[49]

- Grid West would be a public utility under the Federal Power Act that would not have to satisfy the requirements of Order 2000, but instead Order 888;
- a non-jurisdictional utility over which FERC has limited authority, would not, as a result of participation in Grid West, be subject to any additional review;
- BPA would not need prior approval from the Commission in the event it decided to withdraw from Grid West;
- transmission owners, offering service through the Grid West tariff, could continue to serve as transmission providers for their pre-existing transmission agreements; and,
- while FERC could not bind future commissions it confirmed that its decision will provide guidance for future commissions.

The risks asserted regarding FERC's authority to act and effectiveness of its regulation can also be raised with respect to existing wholesale power market structures. For example, much of the power traded in the region today is transacted under the market-based Western Systems Power Pool agreement, while requirements service transacts under cost of service rates. It is not within the scope of the workgroup's charter to compare the legal protections afforded wholesale customers who choose different wholesale power products.

8.5. Governance and Lack of True Independence

The perceived risk is that Grid West will be that the regulatory process will be dominated by "focused economic interests" ignoring interests of smaller (less influential) parties.

[49] 112 FERC ¶61,012.

The Pacific Northwest's long tradition of public involvement and established advocacy organizations, together with its broadly representative governance structure should hedge against this risk. The report by the National Association of Public Administration (NAPA) reinforced this statement and concluded that "the bylaws establish accountability to regional interests while maintaining independence of the governance structure from particular special interests."[50]

8.6. Prospects for Cost Shifts

A structural change in the existing model for transacting power is likely to shift wealth. There are a number of potential causes for this, including:

(1) Changes in the way that transmission costs are recovered.
(2) Shifts of wealth from region-to-region as a result of increased market access.
(3) New and different incentives for generation transactions.
(4) Changes in transmission rate design, e.g., segmentation.

To some extent the risk of "cost shift" has been hedged with careful consideration given to transmission market design, pricing plans and, providing incentives that do not benefit one party over another, e.g., voluntary participation in balancing markets. The potential for cost shifts will, however, be studied in more detail if development of Grid West continues after Decision Point 2.

8.7. Uneconomic Real Power Loss Provisions

There is a perceived risk that costs will shift as a result of a change in the real power loss methodology.

Customers can elect to take service under pre-existing transmission service agreements that contain company specific loss factors that are subject to revision just as they are today. It is premature to speculate about the loss methodology for Grid West tariff service. If development of Grid West continues after Decision Point 2, this risk will be studied in greater detail.

[50] National Association of Public Administration. "Grid West:An Assessment Of The Proposed Governance Structure". October 2004. Page 30.

8.8. Short-term Time Horizon

There is a perceived risk that Grid West would increase exposure to short-term power costs due to greater reliance upon short-term markets and as a result, lead to more volatility in power costs and rates.

The architects of Grid West operational and market design have included numerous provisions to preserve and bolster the existing, long-term, bilateral market to allow customers to limit exposure to the volatility of real-time prices. The Real-Time Balancing Service in the Grid West Market and Operational Design is not intended to be a source for requirements service. Existing opportunities to hedge power supply risk through construction and wholesale supply contracts are facilitated, not deterred, by the design.

8.9. Conservatism in Operation

There is a perception that incentives to ensure reliability will result in Grid West operating the transmission system closer to conservatively estimated limits (limits that trigger higher prices or curtailments) because Grid West's performance is likely to be based on its transmission operation as they affect power markets through the RCS market and the real-time energy market.

Ironically, a similar argument could be made that Grid West would be pressured to operate the system too aggressively, focusing on efficiency over reliability. It has long been the experience of utility operators that conservatism in operations is inversely proportional to knowledge about system state—that is, if less is known about system state, operators tend to be more conservative. Significant improvements in tools for power system monitoring and operational planning have been made over the last several decades. Grid West provides the region with an opportunity to implement mature technologies for region-wide system monitoring and control that would be difficult, if not impossible, to implement on a piecemeal basis. Detailed specifications for these systems and operating procedures will be studied in greater detail if Grid West development continues after Decision Point 2.

8.10. Market Power

There is a perception of increased risk in obtaining fair market prices with competitive real-time markets and the existence of the same commercial entity on both sides of a constraint, e.g., BPA. There is also a perception that the market monitor activity will constrain the market from performing freely and enabling economically efficient demand and supply responses to prices.

This risk may be greater under the existing market structure than under Grid West. Market concentration, measured by ownership of generation relative to load in a relevant geographical region, will not change substantially upon formation of Grid West. But factors that mitigate concentration of market power, such as increased ATC and greater market scope, are possible with Grid West. Nevertheless, Grid West does not propose to alter the existing abilities of parties to transact in bilateral (long- and short-term) markets or construct generating facilities that physically hedge against price risk. Balancing markets will include more, not less, potential suppliers under the Grid West proposal.

8.11. Erosion or Extension of Rights under Existing Contracts

There is a perception that Grid West will re-interpret (potentially abrogate or call for an "open season") all existing contracts.

It has been the express intent of Grid West market designers to preserve existing contracts, and the rights to do so, as discussed above, has been confirmed by FERC.

8.12. Loads Pay

There is a perception of risk that regional loads become the "dumping ground" for costs that could be assigned to other transmission users, e.g., generators, who are moving power throughout the region.

Principles of allocating costs to those who cause them are not altered by Grid West. Each relevant regulatory jurisdiction will continue to be the forum where disputes over cost allocation are heard.

8.13. Market Mismanagement and RTO/Customer Relationships

The potential for Grid West taking actions that actually interfere with the operation of the market place is perceived to be a risk by some members of the group. Discontent among municipal utilities in California, and the CATO Institute's recent policy paper taking a critical view of electric power deregulation are cited as examples to illustrate this perceived risk.

The risk of market dysfunction has been present for decades. Allegations and examples of market failures are certainly not new to the industry. Prior to California AB 1890, municipal utilities in California and throughout the U.S., for that matter, prosecuted numerous complaints at FERC regarding discriminatory practices and market interference. On the second point, the CATO Institute's most recent prescription for market reform—a return to vertical integration—may not be viewed as realistic in a region where wholesale customers, that are not vertically integrated, are a significant segment of the industry. [51]

Grid West's Market and Operational Design is substantially different from the retail access model adopted by California or the Standard Market Design lofted by FERC in 2003. Grid West has taken great pains to be compatible with existing markets and enable new services where needs have been identified.

[51] Van Doren, Peter and Jerry Taylor. "Rethinking Electricity Restructuring". November 30, 2004. Policy Analysis No. 530. www.cato.org.

9. Links to Appendices

9.1. BPA paper and worksheets on Regulating Reserves

reg savings 2.xls
ReportAppendices\01_Notes on Reg Methods.doc

9.2. PowerWorld results on Redispatch Efficiencies

[To be prepared]
Map of NW Flowgates ReportAppendices\Node_Map_075_draft.pdf
Price Spread Anomalies: Prelim_market_spreads_and_TX_usage.doc

9.3. BPA paper on Bulk Electric System Reliability

Est_Value_Avoided_Cascading_Disturbance_2.doc
gross_state_product_new_estimate.xls

9.4. PacifiCorp paper on Power Delivery System Reliability – Momentary and Sustained

Customer_cost_for_Sustained_Outages-v2.doc

9.5. PacifiCorp Papers on Reconfiguration-Transmission Utilization

RnR_GridView.pdf
PowerWorld Alternative RCS Analysis:
PowerWorld_Alt_RCS_and_Incr_TX_Util.doc

9.6. Construction Deferral

Construction Deferral Worksheet Example: Construction Def1.xls

9.7. Conservation and Demand Side Management

Demand_Side_Measures_And_Grid_West_Draft_July_11_2005.doc
DSM&GW_SSG-WI_GenCosts.xls

9.8. Survey documents

RRSurvey_102204clean.doc
RRSurvey_WhitepaperSupport_051905.doc
RRSurvey_preliminaryresults_031105.pdf

9.9. Whitepapers

01_Regulating_Reserves.doc
06_Pancaking-2.doc
08_RRWorkgroup_Whitepapers_MarketMonitoring_Final.doc
12_Technological_Innovations-June13.doc
Grid_West_risks_with_comments.doc

10. Glossary of Terms

Acronym or Term	Definition or Description
AFC	**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. [TSLG]
AGC	**Automatic Generation Control** – Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority’s interchange schedule plus Frequency Bias. [NERC]
ATC	**Available Transmission Capability** – A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. [NERC]
Bulk Electric System	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition. [NERC]
CCA	**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.
Contract Path	An agreed upon path for the continuous flow of electrical power between the parties of an Interchange Transaction. Typically a legal rather than physical definition used to specify points of receipt and delivery in most transmission tariffs.
Control Area	An electric power system bounded by interconnection (tie-line) metering and telemetry. The Control Area Operator controls generation to maintain its interchange schedule with

	other control areas in the interconnection, to maintain instantaneous load/resource balance within its system, and contributes to frequency regulation of the interconnection. [TSLG]
CPS1 and CPS2	**Control Performance Standard** – The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Curtailment	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Cutplane	A group of one or more transmission system branch elements (e.g. lines, transformers, etc.) on a transmission system. See Node_Map_075_draft.pdf for an illustration of cutplanes in the Northwest.
Disturbance	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
DSM	**Demand Side Management** – The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
EPRI	**Electric Power Research Institute**
Flowgate	A designated cutplane on the transmission system through which the affected by Scheduled Interchange and parallel flows that may limit secure operation of the transmission grid.
IWR	**Injection-Withdrawal Right** – The right to submit a day-ahead Injection-Withdrawal Schedule. [TLSG]
Interchange Transaction	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries. [NERC]
LSE	**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.
Market and	The conceptual framework for implementing Grid West's

Operational Design	Basic Features. [TSLG]
NERC	**North American Electric Reliability Council**
NIPPC	**Northwest Independent Power Producers Coalition**
NRTA	**Northwest Regional Transmission Association**
NWPP	**Northwest Power Pool**
OASIS	**Open Access Same-time Information System**
OPF	**Optimal Power Flow**
OTC	**Operating Transfer Capability** – TTC adjusted for based on operational considerations and limitations. [TSLG]
RAS	**Remedial Action Scheme**
RMATS	**Rocky Mountain Area Transmission Study**
SAIDI	**System Average Interruption Duration Index**
SAIFI	**System Average Interruption Frequency Index**
SSG-WI	**Seams Steering Group-Western Interconnection**
TTC	**Total Transmission Capacity** or **Total Transfer Capability**
WECC	**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. www.wecc.biz [TSLG]
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. [TSLG]
WRTA	**Western Regional Transmission Association**
WSPP	**Western Systems Power Pool**