<u>BPA Grid West Benefit Assessment for Decision Point 2</u>

August 4, 2005

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Introduction

BPA committed to evaluating the expected costs and benefits of Grid West prior to its September 2005 decision as to whether or not to continue supporting the development of the Grid West structure/institution - also known as "Decision Point 2" (DP2). This paper documents the results of that effort. For Decision Point 2, we have evaluated benefits from a regional perspective. If BPA decides to pursue TIG or Grid West after Decision Point 2, we will begin the more difficult and detailed tasks of assessing the *distribution* of costs and benefits disaggregated to at least a state-by-state level.

As part of its efforts to meet this commitment, BPA has participated in the Regional Review Group's (RRG) Risk Reward Group (RnR) and the Consolidated Control Area (CCA) benefit assessment exercise. The RnR group has been meeting since spring of 2004. Initially it was charged with assessing the costs, benefits and risks associated with the proposed Grid West design. Eventually, the Transmission Service Liaison Group (TSLG) and its consultant, the Structure Group, took on the task of developing a detailed cost estimate, leaving the benefit and risk assessment in the hands of the RnR group. The RnR accomplished its tasks by 1) conducting a detailed survey of regional transmission owners, marketers, public utilities, and private utilities to ascertain and better understand the transmission problems that Grid West is charged with resolving. 2) reviewing existing RTO/Grid West benefit studies to glean relevant data, and 3) incorporating new analyses, as appropriate, to assess potential Grid West benefits. In addition, the Consolidated Control Area benefit assessment group ran models and conducted analyses to determine the potential benefits of the consolidation proposal.

BPA also convened an internal group of analysts to follow and provide input to the external work, and to conduct its own analysis as needed – this group has been meeting since the inception of Grid West.

On July 20th, the external RnR group presented its estimate of benefits to the region. These estimates were provided in a "menu" format, so that participants might select the estimates and benefit sources that best fit their vision and understanding of Grid West. BPA has taken that menu, selected benefit estimates we think most accurately capture the expected benefits of Grid West, added some of our own analysis, and derived a BPA estimate of regional benefits associated with Grid West.

Overview of Grid West Benefit Sources

Grid West's design is a response to specific problems with regional transmission transactions, as defined by the Regional Representatives Group in 2003 and further delineated in the RRG's 2005 Risk Reward Survey [1]. It is anticipated that Grid West's provision of solutions to these problems will yield benefits to the region. This study will examine the anticipated *regional* benefits of consolidation. The study of state-by-state impacts of costs and benefits will be conducted if the region votes to seat a Grid West developmental board and prior to Decision Point 4 (whether or not to sign a transmission operating agreement with Grid West).

Single Available Flowgate Capacity Calculations For All GW Participants:

A. The global view of schedules on at least a day ahead basis allows for a more *reliable operation of the NW transmission system* than does today's balkanized scheduling protocol. The global view of schedules allows foresight into dispatch problems and loop flow prior to real time. This, in turn, allows for better anticipation of transmission flows than does today's multi-CA scheduling protocol. It is important to note that the Pacific Northwest Security Coordinator (PNSC) currently provides and will continue to provide real time oversight & security for the GW transmission system – thus the increment of security expected from Grid West is associated with the day ahead view.

B. Single system view of schedules increases ATC/AFC – akin to TBL's efforts, only on a broader scale. The result will be the ability to net some loads and to more accurately anticipate physical flows. An increase in AFC will, in turn, leads to more efficient dispatch due to the increase in dispatch options.

C. Outage information, as coordinated by Grid West, is likely to be more transparent than it is today. That information will be incorporated into and influenced by the centralized calculation of AFC – giving Grid West the ability to minimize the lost opportunity costs associated with outages.

D. Transmission construction deferral: To the extent that AFC is released due to the single operator AFC calculations, it will delay the need for construction of new facilities to meet load growth.

Reconfiguration Market:

A. Improves *liquidity of transmission markets* by providing a new mechanism for reconfiguring existing rights and issuing new rights on an injection withdrawal basis.

B. Allows for *more efficient dispatch of generating resources* by opening up transmission options.

[1] For survey description and results, see *http://www.gridwest.org/Doc/RnRCompilation_RRGPres_Feb2405.pdf* and *http://www.gridwest.org/Doc/RRSurvey_preliminaryresults_031105.pdf*

C. Allows for more efficient dispatch of generating resources by eliminating the false price signals conveyed by short term pancaked transmission rates. *Note: we do not anticipate a decrease in the fixed cost of transmission, merely a re-assignment of that cost recovery to a more appropriate fixed-cost recovery mechanism.*

D. *Increases AFC by providing for more transmission trading options*. This, in turn, provides opportunities for more efficient dispatch.

Consolidation of Control Areas (CCA)

A. *Reliability benefits* – CCA gives more direct control of generating resources in emergency situations and more effective response/response time. This has the effect of giving operators control over generation in the face of an emergency, providing a more effective means for addressing problems than does the current mechanism of curtailment of transmission schedules. Thus, it is anticipated that the GW CCA will reduce the probability of cascading outages.

To substantiate this claim, we will provide reference to TBL expertise as to the extent of the problem and the degree to which it will be solved by Grid West.

B. *Regulation benefits* – The CCA's pooled load following and regulation reduce the amount of capacity that must be held out for meeting these needs.

C. *Economic Redispatch* – Consolidators can voluntarily make incremental ("incs") and decremental ("decs") bids into a real time redispatch pool . These incs and decs can be used to efficiently meet regulation and load following needs, and to economically redispatch consolidator's schedules based on physical transmission limits (as opposed to the contractual limits upon which their transmission schedule was based). These instruments lead to more efficient, more flexible redispatch options than those faced by separate control area operation. They also provide real time detailed price signals which can assist in market monitoring efforts, provide clearer incentives for transmission and generation construction, and

B. *Contingency Reserves* - The CCA will allow for day ahead trading of resources to meet its contingency (i.e., spinning) reserve requirement. A more liquid market for such reserves can lead to more efficient assignment of units to meet those reserves and ultimately a cheaper cost of real time dispatch of generation.

Planning/Coordination

Grid West's planning responsibilities will include:

- Determining the capability of the Grid West grid.
- Assessing the transmission adequacy of the Grid West grid
- Developing and enforcing interconnection standards.

- Providing planning information to the AFC market.
- Coordinating transmission expansion activities.
- Providing backstop assurance for investment in reliability if needed.

These measures should provide the following regional benefits:

A. Consistent assessments of capacity, adequacy and security of the regional grid.

B. Clear authority for main grid planning should ensure the integrity of the grid over time and reduce the probability of region-wide outages.

C. Provides a one-stop transmission planning information source for market participants and project sponsors.

D. Provides independent planning from a one-utility regional perspective that will help identify least cost solutions without regard to existing control area boundaries.

E. Backstop authority should serve to improve long term reliability by ensuring that transmission reliability investments are made.

F. Provides a better mechanism for distributing regional transmission costs.

Grid West Benefits: Summary of Quantitative Estimates

BPA's quantitative estimates of Grid West benefits are primarily drawn from work of the external RRG sponsored Risk Reward workgroup (RnR). BPA staff participated in all of this external work, and an internal Cost Benefit team was engaged to review the results internally (for internal and external participation information, see Appendix 1 – "BPA Grid West Cost Benefit Activities for Decision Point 2"). This group began meeting in the spring of 2004 and presented its preliminary results in an RRG seminar on July 20/21st of 2005. The RnR results were presented as a menu of expected benefits with high, medium, and low benefit quantities (in US Dollars/year) derived for each of 7 categories. BPA has selected from this menu the estimates it deems most reasonable from a conservative perspective. Appendix 2 presents the RnR menu from which BPA selected its estimated benefits. A primary difference between the BPA estimate and the RRG estimate is that BPA chose to only adopt the quantified benefits associated with the consolidation of 3 control areas, not those associated with the consolidation of all filing utilities (10 CCA case). BPA has put the potential benefits associated with the consolidation of more than the 3 control areas who are currently exploring consolidation into our unquantified benefit category.

Benefit Summary

The expected benefits, and methods used to derive those benefits, are summarized below. Complete detail is provided on a benefit-by-benefit basis further on in this report.

BPA ESTIMATE: Quantified Regional Benefits of Grid West			**$ Million/year**	
Item	**Potential Benefit**	**Facilitating GW Policies**	**High**	**Low**
1	Reliability: Cascading Outage Prevention	1. GW DA Scheduling 2. Planning 3. Outage Coordination 4. Consolidation of CA's 5. CCA Redispatch 6. CCA Reliability Authority	$62	$27
2	Increased Transmission capacity.	Reconfiguration Service & Single Scheduling Entity	$15	$9
3	Regulating Reserves	CCA regulating pool	$8	$5
4	RT Redispatch Efficiencies	CCA RT redispatch market	$56	$41
5	Contingency Reserves	CCA AS Market	$30	$20
6	De-pancaking	Reconfiguration Service	$10	$4
		TOTAL	***$181***	***$106***

Method Summary:

Item 1: Reliability (Cascading Outages)

Benefits that could result from avoiding catastrophic outages were derived from the 2004 Gross Product for Grid West. Based upon US Census Bureau wage and earning data, it was assumed that 85% of total production occurs during weekdays and 15% on the weekends. The existence of Grid West was assumed to enable avoidance of 1 catastrophic outage every 20 years or 1 catastrophic outage of 1 productive day every 15 years. An outage is assumed to result in 50% loss of a pro-rated daily GDP (the remaining 50% would be recovered or protected by back-up generation). The high estimate reflects results of 1 avoided weekday outage every 15 years, the low estimate reflects results of 1 avoided weekend outage every 20 years.

These estimates are supported by the work of Bill Mittelstadt, BPA transmission engineer and reliability expert who assisted in analyzing the causes of the East Coast outage. Mittelstadt reviewed NERC records of large disturbances in the WECC over the last 12 years and found that 45% of the causes of these outages would be likely mitigated by Grid West. See the BPA Grid West Benefit analysis for details.

Item 2: Increased Transmission Capacity

Benefits derive from increased access to existing transmission capacity as a result of more liquid and transparent transmission markets and as a result of Grid West's charge to merge regional schedules through before-real-time single area scheduling. This estimates what the benefits would be if the these features yield 3% or 5%, more available flow capacity (AFC). Grid View was run to estimate the least cost dispatch to meet loads over 1 year in the Grid West footprint with different transmission availability numbers. The measured benefit derives from the less expensive generation dispatch that occurs when more transmission is available. The high estimate assumes a 5% improvement over the baseline, the low assumes a 3% improvement. (*Note: These figures were derated by 50% as compared with the RRG results, to account for the potential overlap between measurements of the benefits of increased transmission capacity and those accruing as a result of a real time balancing market).*

Item 3: Regulation Reserves

These benefits accrue when regulating reserves are pooled and the magnitude of expected variation in load is reduced, resulting in a reduced need for regulating reserves. Studies were performed by TBL's Bart McManus in 2005 - he examined the actual variation in loads for BPA, PacifiCorp and Idaho Power over 3 years and 4 seasons. The benefits cited are based on a 60-minute rolling average deviation from average load. The high estimate values the resulting capacity savings, 109 MWs, at $6 per kW month, the low was valued at $4 per kW month (based on PBL trader estimates of the value of capacity).

Item 4: Real Time Redispatch Efficiencies

PowerWorld optimal power flow analyses were used to calculate potential production cost savings resulting from the CCA Real Time Balancing service. PowerWorld was run using generator data from SSG-WI and transmission, load, and unit commitment data from WECC operating cases. The model was used to simulate a base case where least cost real time dispatch would be achieved with each GW control area minimizing operating costs independently. The future allows Idaho Power Company, PacifiCorp, and BPA (the consolidators) to minimize real time control area costs amongst themselves without regard to scheduling constraints. The difference in production costs between the base and future case is the anticipated Grid West benefit. Benefits for 8 representative hours in a year were estimated (heavy load and light load hours for each of the 4 seasons) and multiplied up to represent a full year's savings. .

The sensitivity of the resulting dispatch efficiencies to the price of hydroelectric surplus sales (which are a function of the value of power in California into the storable future) was tested. Five different cases were run: $20/MW-hour, $30/MWh; $40/MW-hour; $50/MW-hour; and, $65/MW-hour, as well as a run using Dow Jones average prices at the Mid-C trading hub. BPA's low estimate of benefits is a summation of the lowest benefits for each season of the year. The high estimate is based upon the Dow Jones runs.

Item 5: Contingency Reserves (Spinning and Supplemental)

The NWPP already pools contingency reserves – but they do not meet those reserves on a *regional* least-cost basis (each control area meets its reduced reserve requirement on an internal least cost basis). Consolidating Control Areas will meet their reserve requirement through a reserves market that combines resources and allows for a more optimal commitment of generating units. This more optimal commitment translates into a more optimal dispatch of generation in real time.

Henwood Energy Services conducted a study of these benefits on behalf of Snohomish PUD in September of 2004. BPA's high estimate de-rates their results ($73 million in benefits for the Grid West Region) by 44% as only 56% of Grid West load is assumed to participate in the CCA. This estimate is de-rated again to reflect the fact that short term reserves trades occur to a small degree today. We assumed a 25% to reduction in our high estimate and a 50% in our low case.

Item 6: Pricing Pancakes

BPA's estimated benefits of eliminating price pancakes were derived from two different studies. The high estimate is based on the PacifiCorp's runs of its GridView model wherein they simulated an optimal security constrained dispatch in the Grid West region with and without wheeling rates. The PacifiCorp results were de-rated by 50% to reflect potential overlap with the Real Time Balancing service analysis. The previously mentioned Henwood study also looked at the effects pancaking under extremely conservative assumptions and found there to be about $4 million in potential benefits – this figure comprises our low estimate.

Quantitative Estimate: Reliability

BPA staff and management spent a good deal of time exploring, developing and understanding the potential reliability benefits associated with Grid West. This level of effort was warranted as the need for improving BPA's ability to maintain existing reliability standards is one of the primary reasons that BPA is exploring Grid West and TIG.

BPA is anticipating that, without new ways of managing transmission, the likelihood and frequency of disturbances in its service territory is going to increase over time. The reasons for this concern have not changed significantly since the October 2000 report developed for RTO West, "RTO West Potential Benefits And Costs – Final Draft", October, 2000[2]. That report listed the following reasons for changes in the reliability "playing field".

Previous Conditions	Emerging Conditions
Relatively large resources	Smaller, more numerous resources
Long term firm contracts	Contracts shorter in duration More non firm transactions
Bulk power transactions relatively stable and predictable	Bulk power transactions relatively variable and less predictable
Assessment of system security is made from a stable base (narrower, more predictable range of potential operating states)	Assessment of system security made from a more variable base (wider, less predictable range of potential operating states
Limited and knowledgeable set of utility players	More players with divergent interests, less experience, making more transactions
Hydro system resource flexibility readily dispatched to support the transmission system	Environmental constraints limiting resource operation in support of the transmission system
Unused transmission capacity and high security margins	High transmission utilization and operation closer to security limits
Limited competition – little incentive for reducing reliability investments	Utilities less willing to make transmission reliability investments as many do not produce increased revenues
Market rules and reliability rules developed together	Market rules changing – reliability rules not keeping pace
	More system through-put

These concerns were reiterated in BPA's March 2005 "Keeping Current" publication: "Wanted: One-utility transmission for the Pacific Northwest"[3] That document spells out the reason that a regional transmission solution is needed as we move into the future. Among other things, it points out that:

[2] http://www.nwrto.com/Doc/Benefit_Cost_Study_FinalDraft_Oct232000.PDF)
[3] http://www.bpa.gov/corporate/pubs/Keeping/05kc/kc0305.pdf

- More than 20 generating and transmitting utilities rely on a single Northwest grid that is managed by 17 control area operators.
- BPA built no new major transmission lines from 1988-2000, and has recently added just over 150 miles of new 500 kV line, expanding the grid by 1%.
- We are experiencing too many "near misses" with respect to system outages. The document cites a particular near miss which started with birds in Arizona disturbing a 230 kV line and backup system failures – the event tripped out eight 230 kV lines and ten 500-kV lines, resulting in a loss of over 400 MWs of generation. Had this same event happened on a hotter day, it could have disturbed generation in the Northwest. Another disturbance was cited in which a minor event in Alberta caused dramatic power swings at the California Oregon border. A third case was overloads on Path 18 between Montana and Idaho that was very difficult to manage. Operators were close to dropping load
- Cut planes (points where the grid gets congested) have proliferated in the last few years – in 1998 we had 5, in 2004 the Northwest had had 15.

Reliability Impact Analysis

BPA has had these concerns, and their solutions, in mind as it has participated in the development of the Grid West design. TBL's Bill Mittelstadt[4] and Don Watkins joined with BPA's Industry Restructuring staff to analyze the anticipated reliability effects of Grid West. The full output of this analysis is attached in Appendix 3. A summary of its results is provided below.

The proposed Grid West design was evaluated from a reliability perspective and found to have the following features that will likely enhance reliability:

A. Independent, centralized state estimator

Grid West will implement a State Estimator, which will enable operators to evaluate the impact of transmission rights and schedules well in advance of the hour of delivery, as well as in real-time. This should provide for an improved ability to manage the system and anticipate transmission problems before they occur. SE features include:

- Performs analyses automatically every few minutes based on real-time conditions.
- Able to perform analyses in study mode using preschedules, or planned load/generation patterns and planned outages as input.
- Performs power flow, contingency, and voltage stability analyses.

[4] Mr. Mittelstadt has served as the Principal Engineer at the Bonneville Power Administration in the area of transmission system planning. He is a registered professional engineer in the State of Oregon and a Fellow of the Institute of Electrical and Electronic Engineers ('93). Bill has worked extensively on reliability and planning issues and has served as chair of various Western Electricity Coordinating Council committees. He was also on the U.S. – Canada Power System Outage Task Force that examined the causes of the August 14 East Coast outage.

- Model uses approved flow limits, relaying standards, planning standards, planning and operating margins, system characteristics, Remedial Action Schemes, etc.

B. Centralized Planning/Backstop authority

Grid West will have backstop authority for transmission construction. In the long run this will provide for true one-region planning, assurance that needed construction will get built, and a more reliable system. It will also help ensure that enhancements address the needs of maintaining main grid reliability – including stability controls. Features include:

- A single planning standard will be applied to the Grid West Managed Transmission System (GWMT) using a flow-based approach.
- Develop and maintain transmission and resource models, methodologies and tools to evaluate system performance and resource adequacy.
- Define, collect or develop and share information required for planning, including:
  - Transmission facility characteristics and ratings
  - Demand resource forecasts (capacity and energy)
  - Generator unit performance characteristics and capabilities
  - Long term capacity purchases and sales
- Evaluate plans for customer service – transmission purchases and integration requests.
- Review and determine TTC, IROL, and SOL values.
- Assess, develop, document and report on resource and transmission expansion plans and their implementation.
- Coordinate projects requiring transmission outages that can impact reliability and firm transactions.
- Evaluate the impact of revised transmission and generator in-service dates.
- Work with adjacent areas so that system models and resource and transmission expansion plans take into account modifications in adjacent areas.
- Prepare regional power flow and stability data bases

C. Outage Coordination.

Grid West participants will conduct outage planning amongst themselves. This could provide for outages that more directly support reliability from a region-wide perspective. Features include:

- Outage coordination is based on the current NWPP process.
- All Grid West participants will coordinate outages through Grid West.
- Facility owners will submit generation and transmission outages to Grid West.
- Grid West will evaluate transmission outage requests against reliability criteria and known generation outages and approve requests, or propose changes (detailed Grid West authority will be spelled out in the Transmission Agreement).

D. Consolidated Control Area: Single operation of consolidated control area.

The single control area operation of at least BPA, PACE, PACW and ID PWR provides for more direct communication with PNSC and more direct control over generators (as opposed to schedules) in the face of a transmission problem. Also helps to manage all consolidated flow paths in real time. Also provides a better tool, redispatch, for managing transmission overloads than does TLR. CCA features include:

- Primary & Backup control centers, with dual redundancy for all critical control systems.
- Participants are required to provide balanced load and generation schedules, including offers of IOS necessary to support those schedules. Load forecasts and schedules will be validated for accuracy and feasibility by Grid West.
- Central calculation of Area Control Error and dispatch of generation from the IOS resource stack using a Security Constrained Economic Dispatch (SCED) algorithm.
- Re-dispatch generation from the balancing stack to clear congestion.
- Curtail schedules, generation and load as required to maintain reliability.
- Uniform application of WECC/NERC Reliability Standards including all Category A-C Performance levels in both planning and operations.

E.Consolidated Control Area: Balancing Market

The CCA's balancing market provides a clear mechanism for compensating for real time changes to scheduled and unscheduled flows – this may make participants more willing to redispatch for reliability and will give a more direct and coordinated response to congestion. Features include:

- Balancing offers can be made by CCA resources and resources outside the CCA.
- Offers do not need transmission rights attached, except to get the resources to the CCA if the offered resource is outside the CCA.
- Offers are priced by the generation owner, subject to a cap that will be set by Grid West.
- Resources are dispatched in merit (price) order, subject to congestion, using the SCED algorithm.

F. Flow-Based ATC & Scheduling

Grid West will estimate ATC/AFC using a flow-based methodology. This is expected to produce a more accurate estimate of available flow capacity on constrained paths than we currently have. Injection/withdrawal scheduling, coupled with flow-based analysis tools will enable Grid West to anticipate congestion based on preschedules and to prepare for or take corrective action in advance of the hour of delivery, reducing rushed decisions in real time. It will also give a better indication of loop flow impacts on congested paths. The benefits of Grid West accomplishing this extend beyond those associated with a TBL-only implementation.

The BPA team used these features to analyze the expected effect of Grid West on reliability. The method used was as follows:

1. NERC disturbance reports for 20 outages over the last 12 years (18 of which wereWest Coast outages) were reviewed to determine the causes of outages.
2. The causes that would likely have been mitigated were Grid West in place were identified.
3. The percentage of causes that would have been mitigated by Grid West was determined.

Following is a summary of the results of this Impact Analysis:

<u>Grid West Reliability Impact Analysis: Causal Review of 18 West Coast Outages</u>

Disturbance Issue*	**Mitigated by GW?**	**Occurrences**
Not Ready for N-1	N	0
Insufficient time to readjust	*Y*	*0*
Not Ready for N-1, N-1	*Y*	*0*
Not Ready for N-2 (common corridor)	N	4
Not Ready for N-2 (different corridor)	N	2
ROW Maintenance Issue	N	4
Bus Configuration Problem	*Y*	*1*
Zone 3 or overcurrent relay line tripping	*Y*	*1*
Sympathetic or improper relay operation	N	11
RAS unavailable or improper operation	*Y*	*2*
Substandard voltage limits	*Y*	*0*
Reactive reserve margin not adequate or not monitored	*Y*	*2*
Tower collapse	N	1
Line(s) falling into underbuild	N	1
EMS System Failure	*Y*	*0*
Taking risk under weakened system condition	*Y*	*1*
No means to achieve rapid loading change	*Y*	*1*
No or poor visibility of system outage conditions	*Y*	*1*
Equipment tripping off under stress conditions	N	1
Operators not aware of relay setpoint	N	0
Lines tripping on overload (>20 minutes time to readjust)	*Y*	*2*
Successive lightning strikes	N	0
Lack of Coordination	*Y*	*1*
Load Shedding Miscoordination	N	3
Equipment Maintenance Error	N	0
Fire	N	4
Operator Error	N	2
Operators not aware of insecure state	*Y*	*2*
Total Causes		47
Number of causes that might be mitigated by Grid West		21
% of causes that might be mitigated by Grid West.		45%

Note: Causes in bold italicized font are thought to be mitigated by Grid West

Value of Grid West Reliability Improvements:

Given that:

A. There are increasing threats to the security of the transmission system (reviewed above), an
B. A historical review of widespread disturbances revealed that Grid West is likely to provide significant tools for minimizing such disturbances.

BPA has estimated that Grid West reliability enhancements would be likely to reduce the likelihood of widespread cascading outages. More specifically, we believe that Grid West will facilitate the prevention of at least 1 widespread outage every 20 years as compared with business as usual.

Widespread outages are very expensive to society – as was demonstrated by the August 14 East Coast outage which cost an estimated \$6.4 billion[5] . The majority of these costs derive from the losses experienced when a whole economy is shut down – losses in production opportunities, the cost of idle labor, lost sales, spoilage, damage to machinery, etc. When summed across a whole swath of society, these costs can be significant. There are also human health risks that rise in the absence of electricity, as well as a risk of social unrest (as was experienced in New York in 1977).

In order to put a dollar value on the anticipated Grid West benefit of increased reliability, BPA applied a modified (more conservative) version of the method used to in the August 14 Outage Report to assess the cost of the East Coast outage[6]. This method references the gross annual economic production for the areas affected by the outage, de-rates this production to a daily figure, then assumes that that production is lost in the face of an outage. BPA's analysis further de-rated lost production (beyond the method used for the East Coast Outage) by 50% to reflect the fact that not all production opportunities are lost when the lights go out – some are not electricity dependent and others will make up for lost production in future time periods. BPA's analysis also excludes utility level costs and the cost of spoilage. BPA also believes GW will help the region avoid more common but less widespread outages, but has excluded those benefits from the analysis.

Our analysis and results are as follows:

Step 1: Determine 2004 Gross Production for the Grid West Region (the states of MT, ID, UT, OR, WA, WY, and the province of British Columbia):
US\$761,208 million (based on 2004 data from U.S. Bureau of Economic Analysis and Statistics Canada).

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[5] See "U.S.-Canada Power System Outage Task Force: Final Report on the August 14th Blackout in the United States and Canada", April, 2004 at https://reports.energy.gov/

[6] "*Northeast Outage Likely to Reduce U.S. Earnings By \$6.4 Billion*", Anderson, Patrick L and Geckil, Ilhan K, Anderson Economic Group Working Paper 2003-2.

Step 2: Determine ratio of weekday to weekend production:
About 85% of wages are earned on weekdays, 15% on weekends (based on US Census Bureau wage/earnings data).

Step 3: Determine daily Gross Production for Grid West Region:

Weekday Production:	$2,489,000,000
Weekend Production:	$1,098,000,000

Step 4: Determine cost of 1 productive day's electricity outage (reduce daily GP by 50%)

Weekday Outage Cost:	$1,244,283,000
Weekend Outage Cost:	$548,948,000

Step 5: Divide the avoided cost of one outage by the assumed frequency of avoided outage – 20 years. This yields the expected annual benefit of reliability improvements:

Annual Benefit of avoiding 1 weekday outage every 20 years:	$62 million
Annual Benefit of avoiding 1 weekend-day outage every 20 years:	$ 27 million

Quantitative Estimate: Increased Transmission Capacity

Grid West will provide new mechanisms for managing transmission. It will serve as a single regional scheduling entity developing and implementing flow-based transmission rights. In this capacity, it will be able to net some schedules and find new transmission capacity due to the flow based analysis. BPA's TBL has begun the process of flow-based transmission rights sales, but it can only go so far in the absence of participation by other regional transmission owners.

Some in the region have said that BPA owns 70-80% of transmission in the Grid West region and should be able to accomplish an efficient AFC market itself. In fact, BPA is much more vulnerable to the effects of other system's management than that figure would suggest. The 70-80% figure is a figure that applies to the "BPA region" which is only a subset of the Grid West footprint. If one cuts the figure another way, say the percent of BPA transmission by line miles in the Grid West footprint, BPA owns only 25%. Following is a table reflecting different measures of BPA's transmission ownership as a percentage of the whole.

BPA Transmission Ownership as a Percent of the Northwest Transmission System

Definition of the "Northwest Transmission System"	BPA percentage by mileage	BPA percentage by capacity**
All Grid West Defined Transmission Facilities	25%	41%
All Grid West Transmission Facilities in for Control and/or Pricing	26%	41%
All Grid West Controlled Facilities	37%	43%
All Grid West Controlled Facilities in US	49%	59%
All Grid West Controlled Facilities in BPA Region*	66%	73%

*removed PacifiCorp Utah and Wyoming facilities, removed 75% of NWE facilities

**using average thermal capability of facilities

While there is no denying that BPA is a significant presence in NW transmission ownership, these figures illustrate that there is more to be gained from consolidated determination of AFC than can be gained from BPA's actions alone.

Grid West will also provide a market for reconfiguring then selling transmission services on an injection withdrawal basis. This market is expected to expand transmission markets and allow more fluid access to a broader variety of re-sold transmission rights.

Together, these Grid West policies are expected to have the effect of making more transmission available than is presently the case. If more transmission is available, it can be used to expand and make more efficient generation dispatch options.

Method of Analysis

To determine the benefits associated with more abundant transmission, BPA has relied on a study conducted by PacifiCorp on behalf of the RRG's Risk Reward Workgroup[7]. This study used the GridView model to determine what effect more transmission availability might have on generation production costs using 2004 data. This is the same model that has been used to develop estimates of the benefits of eliminating pancakes. The ABB GridView model is a chronological, hourly production cost model incorporating a decoupled (DC) transmission powerflow. GridView uses linear programming optimization to minimize system production costs and for this study use powerflow and production cost data for the entire Western Interconnection (with loads, generation and transmission defined by SSG-WI planning studies[8]). Both the base case and the "with Grid West" cases are highly optimized in the model.

The steps of analysis were as follows:

Step 1: Run a baseline GridView case which dispatches all Grid West generation on a least cost basis to meet load. Calculate production costs.
Step 2: Run future cases with only 95% and 90% of transmission capacity available. Calculate production costs.
Step 3: For a 10% improvement in AFC, subtract the results of the 90% run from the 100% run.[9]
Step 4: For a 5% improvement in AFC, subtract the results of the 90% run from the 95% run.[10]
Step 5: For a 3% improvement, pro-rate the benefits calculated in step 3 and 4.

The results of this work were as follows:

10% transmission access improvement	$52 million/year in production cost savings.
5% transmission access improvement	$30 million/year in production cost savings.
3% improvement	$18 million/year in production cost savings.

BPA Benefit Estimate:

BPA feels it is reasonable to assume that Grid West could provide between 3% and 5% more transmission availability than is available today. Accordingly, we adopted the $30 million and $18 million figure of expected savings.

However, we recognize that some of these savings have already been calculated in the "redispatch efficiencies" calculations (below). That is to say, the redispatch benefits assess the

[7] Full text of report, which is integrated with the Depancaking report, is available at the Grid West RnR workgroup website: http://rtowest.com/DP2Info.htm.
[8] The SSG-WI 2003 Planning Report and data description are available at the SSG-WI web site http://www.ssg-wi.com/
[9] The 10% improvement came from subtracting the benefits in the following GridView cases: "Base90% TTC less GW 100% TTC" less "Base 100% TTC less GW 100% TTC"
[10] The 5% improvement derived from subtracting the benefits in the following GridView cases: "base 90% TTC less GW 95% TTC" less "Base 90% TTC less GW 90% TTC."

benefits of moving from a flawed dispatch - a dispatch born of imperfect market information, pancaked transmission price signals, inaccurate scheduling constraints. It calculates an optimal power flow having removed all these imperfections. In effect, the PowerWorld redispatch analysis already "cleaned up" the dispatch inefficiencies that are borne of imperfect and unnecessarily limited transmission markets. Thus to add these transmission market efficiencies to the redispatch efficiencies would be to double count benefits.

We correct for this potential double counting by reducing the expected transmission capacity related savings by 50%. This is for two reasons: 1) Redispatch efficiencies are only calculated for expected consolidators – BPA, PacifiCorp and Idaho Power. These consolidators constitute about 56% of Grid West load. The remaining unconsolidated load can still stand to add benefits from the redispatch market and single AFC calculation. 2) The ahead-of-real–time redispatch and AFC market will provide for a more efficient unit commitment, which will in turn provide more efficient resources available for redispatch in real time markets. This is a benefit that would go above and beyond the calculated redispatch benefit.

Therefore the BPA estimates of benefits from increased transmission capacity due to Grid West are as follows:

High Estimate (50% of the 5% improvement in AFC benefits):	$15 million/year
Low Estimate (50% of the 3% improvement in AFC benefits):	$9 million/year.

Quantitative Estimate: Regulating Reserves Savings

These benefits accrue when regulating reserves are pooled and the magnitude of expected variation in load is reduced, resulting in a reduced need for regulating reserves. Studies were performed by TBL's Bart McManus in 2005 - he examined the actual variation in loads for BPA, PacifiCorp and Idaho Power over 3 years and 4 seasons. The benefits cited are based on a 60 minute rolling average deviation from average load. The high estimate values the resulting capacity savings, 109 MWs, at $6 per kW month, the low was valued at $4 per kW month (based on PBL trader estimates of the value of capacity).

Grid West will pool the regulating reserve requirements of those who choose to consolidate control areas. This will allow the variation in load across the consolidating systems to balance out a bit more than they do today which, in turn, will reduce the regulating response capability that the consolidated control areas will need to place under automatic generation control (AGC). Reduced regulating requirements translate into reduced system capacity requirements.

Method of Analysis

In order to measure these benefits, TBL's Bart McManus replicated a study performed by Warren McReynolds for the October 2000 study of RTO West [11]. He collected actual data on load variation for BPA, PacifiCorp and Idaho Power Company for simultaneous time periods in 2004. One week of load data for each season was analyzed.

In order to estimate potential savings in regulation, McManus used 10 second area load data. Area load is a calculated number, total generation minus total interchange. He then calculated the regulation needed using three time frames, 60 minute, 30 minute and 10 minute. For all of these he used the same methodology: calculate a rolling average using 60, 30 or 10 minutes and compare the average to the instantaneous area load

The 10 minute rolling average is more of a traditional regulation benefit, while the 60 minute average represents capacity savings associated with lower requirements for regulation *and* load following. For Grid West regulating reserve benefit we chose to use the 60 minute rolling average, both because it is consistent with the McReynold's study, and because the capacity benefit savings that Grid West is expected to yield should also include those associated with load following.

In his work, McManus noted a caveat to his results: the base numbers are much lower than are actually set aside for regulation in the BPA control area – they reflect what the reserve requirement would be (in both the base and change case) were the region to adopt a NERC-approved relaxed approach to meeting the CPS1 regulating requirement. If one were to assume that Grid West would allow the region (and BPA in particular) to reliably shift to this relaxed standard, then the estimated benefits would be higher yet. The calculated thus represent the minimum benefits that would be associated with regulating savings. Indeed, the final output of

[11] "RTO West Potential Benefits and Costs: Final Draft" October 23, 2000, pp. 19-21 at http://www.nwrto.com/Doc/Benefit_Cost_Study_FinalDraft_Oct232000.PDF)

the RRG's Risk Reward group cited the benefits of relaxing control standards in its high estimate of regulating reserve benefits.

After calculating the estimated reduction in regulation reserve requirements, we assigned a market value to the avoided capacity requirement. The market values used were $4-$6/kW month, as advised by PBL staff.

<u>Results of Analysis</u>

The results of these efforts are presented below:

Estimated Benefits of CCA Regulating Reserve Savings
Based on Bart McManus' Analysis of Load Variances in ID,Pac and BPA

	No CCA	CCA	Delta	Low Value	High Value
10 minute moving average					
July 5-11 '04	176.7	102.4	74.3	$3,566,400	$5,349,600
April 12-18, '04	184.8	109.8	75	$3,600,000	$5,400,000
Jan 27 - Feb. 2, '04	182.7	108	74.7	$3,585,600	$5,378,400
July 7-13, '03	181.7	106.2	75.5	$3,624,000	$5,436,000
30 minute moving average					
July 5-11 '04	230.5	140.3	90.2	$4,329,600	$6,494,400
April 12-18, '04	238.9	148.9	90	$4,320,000	$6,480,000
Jan 27 - Feb. 2, '04	241.8	149.7	92.1	$4,420,800	$6,631,200
July 7-13, '03	236.3	146.4	89.9	$4,315,200	$6,472,800
60 min moving average					
July 5-11 '04	275.4	168	107.4	$5,155,200	$7,732,800
April 12-18, '04	287.1	180.8	106.3	$5,102,400	$7,653,600
Jan 27 - Feb. 2, '04	297.1	186.4	110.7	$5,313,600	$7,970,400
July 7-13, '03	287.3	176.6	110.7	$5,313,600	$7,970,400
	Assumed Value:			**$/MW Yr. Low**	**$/MW Yr. High**
	$4-$6 KW/Month			$48,000	$72,000

"Regulation Requirement" calculated as 99% bandwidth of the absolute value of MW deviations between 10-second instantaneous loads and X minute moving average loads at every 10 second interval during sample week.

BPA Benefit Estimate

For the reasons explained above, BPA adopted the benefits associated with the 60 minute moving average analysis.

High Estimate:	$8 million/year
Low Estimate:	$5 million/year

Quantitative Estimate: Real Time Redispatch Efficiencies

Grid West will operate an important new mechanism for balancing energy amongst those who choose to consolidate. The Real Time Balancing Service (RBS) will allow consolidators to define the source of their balancing energy and, if they wish, make incremental or decremental bids for redispatching scheduled generation to assist other consolidators in meeting their balancing needs at a price that is acceptable to the bidder. Consolidators can also elect to have Grid West redispatch their schedules for economic reasons – in other words, based on the individual consolidators' voluntary bid, Grid West can identify real time trades that would make the system more efficient.

This differs from today's practices in several ways:

1) There is no real time redispatch market today. As transmission operators (TO's) move into real time, they meet their load requirements (net of commitments borne of external sales) by minimizing the cost of running the generating resources within their control area. Those participating in the CCA can meet their commitments by minimizing the cost of generation amongst all participants in the CCA (via the inc/dec mechanism).

2) Close to real time trades today are hampered by the need to secure transmission rights (a process that takes time). However, as we move close to real time, transmission operators know what the actual transmission limits are. In the Grid West world, an independent transmission coordinator can coordinate inc/dec bids subject only to the physical and security constraints of the transmission system. This allows for more liquid real time markets and provides an opportunity to eke a bit more efficiency out of an already efficient system.

3) Grid West will provide for within-hour trades, a market which doesn't exist today and which will allow the region to eke a bit more efficiency out of an already efficient system.

Thus, Grid West will provide an opportunity to make Northwest generation more efficient. The Consolidated Control Area provides this benefit for those who consolidate by providing an inc/dec based real time balancing service that will allow for voluntary economic redispatch. This inc/dec market will also provide more transparent price signals for more delivery points than is provided today.

Method of Analysis: Detail

These benefits were measured by the Consolidated Control Area modeling group for Decision Point 2. After consideration of various modeling options, the group decided to use the PowerWorld OPF model to get at consolidation benefits. PowerWorld's Simulator OPF(TM) (Optimal Power Flow) provides simulation of high voltage power system operations in an AC or DC mode, giving analysts a comprehensive view of issues surrounding electric power flows in a transmission grid. PowerWorld has been used by TBL for years to conduct transmission studies. Its OPF capability provides analysis for the optimal dispatch of generation in an area or group of areas while enforcing the transmission line and interface limits. PowerWorld was well suited to this work as most production cost models essentially assume preschedule matches real-time and cannot see sub-hourly movements in loads and resources. In addition, the optimization routines of these other models tend to produce a one owner optimal dispatch for the system, which does not allow for the modeling of the existing business as usual case, as we optimize for multiple owners over multiple system. The price paid for PowerWorld's specificity is twofold: time and data requirements. The model is run in 1 hour increments and requires a great deal of information about existing schedules, transmission ownership, transmission configuration, generator costs and commitment.

As PowerWorld solves one hour at a time the CCA group looked for a number of powerflow cases to build a crude Load Duration Curve model – a model of exemplary operating hours from which one can extrapolate benefits for the whole year. The key to this task lies is in finding power flow cases where the loads, resources and schedules that are typical for a number of operating hours. WECC produces operating cases by season and load conditions with the express purpose of illustrating "typical" operating conditions. These cases are coordinated through the WECC process by areas and reconciled. This coordination process allows and indeed forces the parties to enter feasible hydro schedules that respect current operating requirements. The result is the best estimate of typical patterns of load, resources and schedules across the Western Interconnection that the CCA group could think of. Unfortunately, WECC only produces a few of these each year. Given the changes in hydro operation, the CCA group looked to use the most recent operating cases plus the disturbance case from June 14, 2004. This gave the CCA group 6 different powerflow cases, fewer than ideal, but enough to be indicative.

WECC power flow data does not include cost information. The heat rate, fuel type, and non-gas fuel cost were entered from the SSG-WI 2003 study work. The gas prices were adjusted to reflect more recent conditions.

The group struggled in deciding how to portray the value of hydro-power. Most resources have a value equivalent to their marginal cost of operations in these super-optimized models – this value is born of basic economic theory that suggests that in the short run, producers bid prices into a market at their marginal cost of operation: If the market clears at a higher price, they are able to cover their fixed cost. If it clears at a price equal to their marginal cost, then at least they haven't lost money (as the fixed cost have to be paid regardless of production levels). If it clears at a price below that which is bid, then that bidder does not sell into the market. Over the long run, if resources don't clear enough money over their marginal costs to cover fixed costs, they are deemed uncompetitive and close down. This theory can be reviewed in any basic economic text. Hydro resources, however, don't fit into the classic model for one primary reason – their fuel supply is limited – if power is sold in one hour, it prevents the sale of electricity from that particular unit of fuel in the next. Thus, hydro must be priced in these models at an opportunity cost not equal to its marginal cost – especially in the Northwest where we have access to California markets where the price tends to be higher. BPA's PBL staff suggested that the right price to use would be the opportunity cost of selling into California in the storable future.

In the end, given the limitations of PowerWorld's linear approximations and the difficulty of predicting hydro value in any particular season, the group decided to enter a variety of opportunity costs for each season in an attempt to capture a range of possible outcomes. High values for hydro opportunity costs would tend to correspond to good storage capability with high market prices (drought with high gas prices where power can be easily stored for sale tomorrow or next week), whereas low hydro opportunity prices would reflect difficult storage or a poor market (e.g. spill). An attempt was also made to limit the quantity of hydro that was available for redispatch in any particular hour by freezing dispatch on all but a few dams – however, it turned out that the model couldn't solve without being able to move all generating units at least a bit. In the end, the unit commitment and generation max and min points from the WECC cases were used to limit the hydro production.

When the areas are consolidated, PowerWorld looks to see if plants that are currently carrying operating reserves (held back below capacity) in one area can be run up to back down expensive generation in another area (moving the reserves to that area). This "balancing energy/redispatch market" is all done respecting transmission limits and the net external schedules. For each case, the model was run with no consolidation of control areas (the base case), for a 4 CCA case (BPA, IPC, PacE, and PacW), and finally for all 10 areas consolidating. The cases were run with hydro opportunity costs of $20, $30, $40, $50, and $65/MWh covering a range of hydro storage and market conditions. The savings were viewed as indicative of the cost savings that could occur each hour, not the specific actions that would be repeated each hour. For example an off peak and on peak 4 CCA run stored 300 MWhs of hydro on BPA's system. The assumption was that BPA could increase its schedule, say to California, at its opportunity cost and sell the extra energy. A rerun of the 4 CCA on peak case with the extra 300 MWh schedule resulted in a net change to BPA's hydro of less than 1 MWh.

<u>Method of Analysis: Summary</u>

To summarize the above discussion, the methods used by the CCA modeling group to estimate redispatch savings were as follows.

For one heavy load hour and one light load hour case, in each season, and for each hydro price assumption ($20 - $65), proceed as follows:

Step 1: Collect data:
Loads: WECC Data
Transmission Configuration: WECC Data
Generating Units: SSGWI Data
Baseline Interchange Schedules: WECC Data

Step 2: Determine baseline production costs:
Run PowerWorld such that, for each separate control area, it minimizes the cost of meeting load net of interchange schedules with each control area's own resources. Calculate baseline production costs (sum the cost of running all dispatched generators for 1 hour).

Step 3: Run PowerWorld such that, for the combined control area, it minimizes the cost of meeting load net of interchange schedules with the consolidated control area's own resources. Non consolidator's costs are minimized as in Step 2. Calculate with/CCA production costs. (sum the cost of running all dispatched generators for 1 hour).

Step 4: Calculate dispatch benefits: Subtract baseline production costs from with/CCA production costs.

Step 5: Multiply results by the number of hours in a year that the case represents.

Results of Analysis:

Below is a brief summary of the results of the PowerWorld runs for the "4 CCA" case – which includes BPA, IPC, PAC East, and PAC West. Complete data sets from the runs (including detailed generator data) will be available on the Grid West website in mid-August[12].

Production Cost Savings Between No CCA and CCA (4 control areas)
Results expressed in $ per hour

Case	Hydro Base Price ($/MWh)				
	$20	**$30**	**$40**	**$50**	**$65**
Heavy					
Spring	$12,927	$10,574	$7,670	$5,862	$8,697
Summer	$10,108	$8,702	$6,552	$9,357	$3,218
Autumn	$12,927	$10,574	$7,670	$5,862	$8,697
Winter	$14,618	$13,645	$13,574	$13,531	$19,758
Light					
Spring	$266	$659	$53	$119	$27
Summer	$12,505	$7,975	$3,850	$775	$194
Autumn	$266	$659	$53	$119	$27
Winter	$7,406	$8,030	$8,534	$8,018	$14,312

Seasonal Tabulation

Heavy	**Seasonal Production Cost Savings ($)**				
Spring (1240 hrs)	$16,029,480	$13,111,760	$9,510,800	$7,268,880	$10,784,280
Summer (1648 hrs)	$16,657,984	$14,340,896	$10,797,696	$15,420,336	$5,303,264
Autumn (816 hrs)	$10,548,432	$8,628,384	$6,258,720	$4,783,392	$7,096,752
Winter (1216 hrs)	$17,775,488	$16,592,320	$16,505,984	$16,453,696	$24,025,728
Light					
Spring (968 hrs)	$257,488	$637,912	$51,304	$115,192	$26,136
Summer (1280 hrs)	$16,006,400	$10,208,000	$4,928,000	$992,000	$248,141
Autumn (680 hrs)	$172,368	$427,032	$34,344	$77,112	$17,496
Winter (956 hrs)	$7,080,136	$7,676,680	$8,158,504	$7,665,208	$13,682,272

[12] http://www.gridwest.org/RRG_GridWest_RiskandReward.htm

Annual Totals

Low	$41,181,141
Dow Jones*	$56,416,193
High	$65,457,195

* Weighted by historical price frequency data from Dow Jones

BPA Estimate

BPA staff, in addition to contributing to the exercises that lead to these results, spent time considering the implications of the results and submitting them to a "reality check". The detailed results of these kinds of models can be voluminous, and fairly vulnerable to changes in assumptions. Comparing the production costs in the base case PowerWorld runs to the production costs in the consolidated case, we found that the results showed a reduction in cost of less than 1%. This result is in keeping with and to some degree confirms our belief that the changes proposed are ones that will shift but not revolutionize the way that business is done today.

In order to maintain a conservative estimate of benefits, BPA chose to cite the low estimate as its own low estimate of regional redispatch benefits, and the "Dow Jones" result for its high estimate.

Accordingly, BPA's estimate of annual redispatch benefits associated with the CCA RBS is:

High: $56 million
Low: $41 million

Quantitative Estimate: Contingency Reserve Benefits

Unlike regulating reserves, the Northwest has already pooled its contingency reserves to capture the capacity savings associated with a reduced reserve requirement. The Northwest Power Pool's reserve sharing agreement provides this benefit. NERC requires that transmission operators carry reserves in an amount equal to the greater of the largest single contingency in its control area or 5% of hydro generation and 7% of thermal generation. The Power Pool makes it so that the largest single contingency in the region is far smaller than the 5%/7% rule – allowing all participants to carry the lower figure in reserves. Contingencies are covered (through the end of the hour) via an automated computer program that belongs to the NWPP but resides at the PNSC. A settlement system is already in place for this type of reserve sharing.

However, today almost all participants meet that requirement with their own resources – there is no common close to real-time market for contingency reserves. One of the reasons that there is not an active market for such reserves is related to restrictions that FERC places on affiliates of non-independent transmission providers. We anticipate that the independence of Grid West and the broad information that the CCA will have, together with its provision of a day-ahead contingency reserve market for consolidators (subject to deliverability), will enable more liquid and efficient reserve markets. We believe these more liquid markets will, in turn, lead to a more efficient commitment of generation units ahead of time and a less expensive real time dispatch of generation . Thus we believe there are benefits to be gained through Grid West's day ahead contingency reserve market – benefits that derive from the ability to meet the existing commitment at a least cost amongst the consolidators, instead of a least cost for each control area.

<u>Method of Analysis</u>

This is the only category for which the RRG's Risk Reward Workgroup relied exclusively on existing studies. We did not, among ourselves, have a model and requisite information that could adequately simulate unit commitment. Thus we relied upon the most recent piece of research on contingency reserve benefits in the Northwest – the Henwood Energy Services study of Grid West benefits commissioned by Snohomish PUD and completed in the fall of 2004[13].

Henwood used their EnterPrise Market Analytics Module, MARKETSYM to estimate the production costs associated with having each control area meet its reserve requirement with its own resources vs. meeting its requirement with a shared pool of generating resources.

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[13] "Final Report: Study of Costs, Benefits and Alternatives to Grid West", prepared for Snohomish County PUD by Henwood Energy Services, October 15, 2004. Can be found at: http://www.snopud.com/AboutthePUD/CustomerNews/SpecialReports/gridwest/reference.ashx?p=2680#

Results

Henwood found that a total of $73 million in benefits might be gleaned in the Grid West region from a more efficient operating reserves market. They warned that they had not derated this benefit to reflect the trades that happen in today’s system.

BPA Estimate

We de-rated the Henwood Estimates by 44% to reflect the fact that the anticipated consolidators (BPA, PAC and IPC) only represent 56% of the Grid West load. We further derated Henwood’s estimate by 25% (in the high case) and 50% (in the low case) to reflect the fact that some efficient trading does happen today.

The results are as follows:

High:	$30 million/year
Low:	$20 million/year

<u>Quantitative Estimate: De-pancaking Benefits</u>

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 new fixed transmission costs.

Transmission pancaking can also have a deleterious effect on resource siting – generation resource developers must sometimes work with several transmission owners to secure access to load. As such, they must often perform multiple transmission impact studies, negotiate multiple long term transmission contracts, and anticipate pancaked short term rates for any surplus sales they wish to make. It is possible that this might prevent construction that would be reasonable were price signals more reflective of the incremental costs they would be imposing on the system.

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 practice may limit efficient trade across multiple control areas.

It is anticipated that Grid West will eliminate pancaking for all new transactions selling rights on an injection/withdrawal rather than control area by control area basis. This result is partially dependent on the final design of long term transmission service, which won't be complete until after decision-point 2. Thus, these benefits will need to be revisited prior to decision point 4 (whether to sign a Grid West Transmission Agreement).

For its decision point 2 analysis, BPA has only included estimates of the benefits of eliminating the pancaked transmission rate itself – not the benefits of unpancaked loss charges. We believe that the depancaking will lead to a slightly more efficient dispatch of generation.

<u>Method of Analysis</u>

Modeling the benefits of pancaking is a challenging exercise. One of the difficult issues to deal with is the idea that transmission that is committed through existing long term contracts is, to some degree, already depancaked – the user has already sunk the cost of using that transmission and will only consider the marginal costs of generation in dispatch. That beneficial effect is, however, mitigated when the contract is in the form of a point to point right which can be resold – then the opportunity cost of using the contract is determined by its value in the market which is, in turn, influenced by the existence of pancakes in short term markets.

To precisely model the effects of pancaking, one would need to catalogue all transmission rights and somehow represent their variable uses (through sheltering, etc.) in an OPF type model that also models the demand for short term and non-firm transmission. The effort required to produce this type of analysis would likely far outweigh the benefits of the estimate.

For decision point 2, BPA has referenced two different modeling efforts that we believe provides bookend depancaking benefits.

The GridView modeling run:

The first effort, a PacifiCorp study using its GridView model, is part and parcel of the modeling conducted for estimating the benefits of increased transmission capacity, described above. This effort assumes the following:

A. Perfectly competitive markets
B. Perfectly optimized transmission usage (excepting the pancaking charge)
C. All transactions face a transmission pancake

It is this final assumption that makes this BPA's upward bound on the effect of pricing pancakes, as one cannot say that all transmission is currently pancaked. However, some postulate that it is the low cost resources (hydro) that are secured with long term transmission contracts, and that these would be dispatched in a similar way with or without pancakes – so their dispatch shouldn't change in this model. It is the high cost resources whose dispatch is shifted, and these are the resources that are more likely to be traded in short term, pancaked transmission markets. If one accepts this argument, it leads to the conclusion that it is reasonable to model the system as if all transactions face transmission pancakes.

The ABB GridView model used in this analysis is a chronological, hourly production cost model incorporating a decoupled (DC) transmission powerflow. GridView uses linear programming optimization to minimize system production costs and for this study use powerflow and production cost data for the entire Western Interconnection (with loads, generation and transmission defined by SSG-WI planning studies[14]). Both the base case and the "with Grid West" cases are highly optimized in the model.

An averaged result of the GridView runs shows $20 million in annual savings from depancaking. More information about this study is attached as Appendix 4.

It is also interesting to note that the 2002 TCA Cost Benefit study[15] was conducted with similar methods and found a benefit in the range of $61 million/year.

[14] The SSG-WI 2003 Planning Report and data description are available at the SSG-WI web site http://www.ssg-wi.com/

[15] " RTO West Benefit Cost Study: Final Report to RTO West Filing Utilities" March 11, 2002, at http://www.rtowest.com/Doc/BenCost_031102_RTOWestBCFinalRevised.pdf Report critique and response at :

The Henwood modeling run:

The Henwood study[16], commissioned by Snohomish PUD and referenced for our contingency reserve benefits also measured the benefits of pancaking. They took the other end of the assumption spectrum by modeling a case where "for the majority of transactions, there are no incremental transmission rate charges"(Page ES3). Only in certain conditions (when BPA paths are full and other non-BPA facilities must be used) does the Henwood analysis reflect pancaked transmission rates. Henwood used their EnterPrise Market Analytics Module, MARKETSYM to make this estimate.

Using these very conservative assumptions Henwood found an annual savings of $4 million resulting from the elimination of the few pancakes that were modeled.

<u>BPA Estimate</u>

BPA used the GridView runs as our high estimate of depancaking benefits, and the Henwood runs for the low benefit. We determined that the benefits counted in the GridView runs may overlap with those accounted for in the PowerWorld estimate of real time redispatch efficiencies (as those runs "clean up" the effects of inefficient before-real time market results). However, the Real Time Redispatch efficiencies were only run for the consolidating control areas (BPA, PAC and IPC) – which only represent about 56% of load. Furthermore, the elimination of pancakes allows for a more efficient unit commitment that can lead to more savings than those measured in the PowerWorld runs (the units it was given to redispatch were a function of pancaked transmission rates). Therefore, we reduce the GridView estimate by 50%.

Accordingly, BPA's estimates of benefits due to de-pancaking are as follows:

High:	$10 million/year
Low:	$4 million/year

[16] "Final Report: Study of Costs, Benefits and Alternatives to Grid West", prepared for Snohomish County PUD by Henwood Energy Services, October 15, 2004. Can be found at: http://www.snopud.com/AboutthePUD/CustomerNews/SpecialReports/gridwest/reference.ashx?p=2680#

Qualitative Benefit Description

Improved Transmission Planning

One of BPA's primary motivations in pursuing restructuring options is to solve ongoing problems in transmission planning. These problems have arisen in a world where markets have become more competitive and utilities have become more reluctant to accept small individual costs in order to promote the greater transmission good. In this new world, the number and composition of market participants have increased and changed - the spirit of cooperation and coordination that existed among the planners in the regulated world is being replaced by competition and confidentiality. In this new world some transmission owners may not have sufficient incentives to accommodate unavoidable adverse consequences of their actions, such as parallel path flow. In this new world, it has been very difficult to get transmission built on a cooperative basis.

Having Grid West responsible for transmission planning for the regional grid should provide a more transparent and effective planning process than the coordinated, yet fragmented, planning process it is envisioned to replace.

Grid West is expected to have the following planning responsibilities and processes:

1. Planning for the Grid West Managed Transmission (GWMT) system will be done on a single-system basis to address overall system reliability, transmission service adequacy, requests for longterm transmission service and integration of proposed transmission expansion projects.

2. The planning process will be open to all stakeholders, with participation anticipated from other federal, state, provincial, local and tribal regulatory authorities and siting agencies.

3. Grid West is envisioned to have specific authority for transmission planning and expansion. The full extent of this authority as it relates to the facilities of Transmission Owners will be specified in the Transmission Agreements to be negotiated between Grid West and the transmission owners prior to Decision Point #3, while the connection between planning and requests for transmission rights and participation of other parties in the planning process will likely be identified in Grid West's tariff. The provisions of the Transmission Agreements will be the same for all Transmission Providers, and they will make Grid West the transmission planning authority for Grid West Managed Transmission.

4. It is anticipated that Grid West's initial backstop authority will be limited to protecting transmission adequacy, responding to transmission service requests for long-term transmission rights and maintaining the transfer

The benefits of Grid West planning include:

A. Consistent assessments of capacity, adequacy and security of the regional grid.

B. Clear authority for main grid planning should ensure the integrity of the grid over time and reduce the probability of region-wide outages. (this benefit has been partially measured in the Grid West reliability benefit estimate)

C. Provides a one-stop transmission planning information source for market participants and project sponsors.

D. Provides independent planning from a one-utility regional perspective that will help identify least cost solutions without regard to existing control area boundaries. (This is probably the most significant unmeasured economic benefit of improved planning)

E. Backstop authority should serve to improve long term reliability by ensuring that transmission reliability investments are made.

F. Provides a better mechanism for distributing regional transmission costs.

Long Term Generation Siting Efficiencies

To the extent that the real time redispatch market creates clearer locational price signals, those signals can lead to more rational generation siting decisions in the long run. This improved price signal effect is augmented by the depancaking of transmission rates.

The question to be answered in order to assess this benefit is as follows:

After a builder has taken into consideration the cost of construction, the cost of fuel, the cost of labor and O&M, and the cost of any needed transmission reinforcements/new construction, and the cost of congestion, - is the anticipated cost of rate pancakes across existing and available transmission lines high enough to discourage construction that would otherwise be financially viable? Similarly, is the expected income from a real time balancing service (into which non-consolidators may bid) enough to encourage construction that would otherwise not be deemed economic?

Many economists believe that the effect of more rational price signals could be significant over long time horizons, and that this benefit should be one of the most significant reasons to pursue restructuring (together with reliability benefits).

We did not have the tools to measure this benefit as of Decision Point 2.

Improved Ability to Monitor Markets

Market monitoring is a function that is essential to Grid West's operation and acceptance – it will help ensure that Grid West's markets and market rules are fair and reasonable. A good market monitor enables an organization like Grid West to learn and adjust to new information and business environments. Thus, to a large degree, BPA sees the market monitor as an essential piece of the Grid West package. It is also important to note that it is likely that a West Coast market monitor will take form in the near future with or without Grid West (development negotiations are underway through the Seams Steering Group – Western Interconnection, or SSG-WI, group). However, Grid West's real time balancing service and centralized reconfiguration auction should provide more specific price information than we currently have access to – this price information will allow the market monitor to perform its job with more accuracy. The value of the pricing information to a market monitor is the incremental value that Grid West brings to the region.

Transmission Construction Deferral

We anticipate that Grid West's ability to produce a region-wide calculation of available flow gate capacity, together with its reconfiguration service, will provide new transmission capacity. This was reviewed in the quantitative benefit category of Increased Transmission Capacity. This increased transmission capacity (which allows for more efficient trades of generation) should also enable the deferral of transmission construction. It is possible that there is some overlap between these two benefit categories.

The quantitative benefits associated with construction deferral are derived from decreased and delayed capital carrying costs. Construction benefits, were they calculated, would be based on the time value of deferring capital expenditures and carrying charges.

More Efficiently Coordinated 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 an unnecessary barrier to delivery of low-cost energy to consumers.

The Northwest does have already have a system for coordinating outages, the Northwest Power Pool's Coordinated Outage System. It is not, however, clear that this coordination is sufficient to support economic maintenance schedules. The RRG's Risk Reward Survey revealed that some in the region believe that transmission providers did not provide adequate justification for reductions in transmission capacity during outages. This is illustrated in the BPA-TBL Transmission Capacity E-mail Forum where subscribers receive a steady stream of concerns about the impacts of maintenance outages on the cost transmission maintenance outages.[17] While it is clear that the region actively discusses the occurrence and scheduling of transmission maintenance outages, the workgroup was unable to identify what systematic methods are used to evaluate the economic impacts of transmission outages on transmission customers or the consumers that they serve.

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

Grid West will improve the outage coordination of participating transmission owners by providing a forum for submission, discussion, evaluation, and coordination of outages that is more detailed than, and happens in advance of, current maintenance practices. It will provide an advocate for a regional perspective on outage impacts that is not currently possible. As an independent entity, Grid West would not have inherent conflicts of interest or commercial bias in its assessments of maintenance outage schedules. More specifically:

- Grid West will continue to participate in NWPP Coordinated Outage System
- Grid West will ultimately be responsible for maintaining a reliable and coordinated system operation for its managed transmission.
- Grid West will require information on planned and/or forced outages of key transmission and generation facilities
- Grid West will review outage requests, considering the following factors:
  - Forecasted peak demand conditions
  - Other known generation and transmission facility outages
  - Impacts on Grid West's ability to honor the awarded Injection/Withdrawal Rights (IWR) and any flexibility of the existing transmission agreements
  - Violation of pre and post-contingent rating of transmission facilities
  - Potential load curtailments
  - Outage plans of adjacent control areas.
- Grid West will publish the initial outage plan 30 days before operating day. Grid West will publish the final outage plan 15 days before operating day.

More Efficient 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. It is not theoretically clear whether or not these benefits were measured in the Real Time Redispatch Efficiencies study – that study focused on efficiency benefits associated with redispatch that corrected for inefficient scheduled energy. It may be that further benefits would be measured if they were measured off of actual energy rather than scheduled energy. This subject will require further analysis after decision point 2.

Unmeasured Reliability Benefits

BPA has not included a number of potential reliability benefits in its quantitative estimates. These include:

- The spoilage of stock on hand
- The restoration of industrial facilities (which may take longer than the blackout, and involve investment in equipment repair)
- Utility level costs of a blackstart: lost income for resources/facilities that take time to restore, cost of restoring operations.
- Potential costs of unrest (riots, looting,etc.)

In the previously mentioned NE blackout cost estimate[18], only 55% of the $6.4 billion derived from the loss of GDP – the remainder derived from spoilage, utility level costs, government costs, and indirect lost earnings. If a similar ration were applied to the GDP –alone analysis we used for our benefit estimate, the total would rise to from the adopted $27-$62 million in annual benefits to $60-$138 in benefits – an increase of $33-$75 million in benefits annually.

Also, benefits of avoiding an outage were measured based on 2004 GDP – a base figure that is likely to grow over time.

Additionally, we have not included measurements of potential improvements in non-cascading, less catastrophic outages that may result from Grid West's improvements (particularly those associated with planning).

If these elements were added into the cost benefit equation, they could increase the valuation significantly.

Demand Side Management Benefits

The current Grid West design includes provisions for allowing DSM to participate in markets. These provisions have not been described in any detail for Decision Point 2. If DSM is allowed to fully participate, it could

1) Reduce the cost of generation production by offering more and cheaper resources into Grid West ancillary service markets and real time balancing markets
2) Prevent monopoly pricing in load pockets by creating more competition regardless of transmission availability.
3) Augment transmission construction deferral benefits, as DSM resources do not require more transmission.

In turn, allowing DSM to participate in Grid West markets will provide incentives for DSM innovation and product development

[18] "*Northeast Outage Likely to Reduce U.S. Earnings By $6.4 Billion*", Anderson, Patrick L and Geckil, Ilhan K, Anderson Economic Group Working Paper 2003-2.

Broader Consolidation of Control Areas

This analysis has been conducted under the assumption that three transmission owners would participate in Grid West: Idaho Power Company, BPA, and PacifiCorp. If more of the Grid West filers were to join the consolidation (a likely scenario, as most of the filers have participated in the development of the CCA and would stand to gain by joining), the benefits would be commensurately higher.

More specifically, the benefits *might* increase as follows (expressed in $millions/year of benefits):

10 CCA benefits:		**High**	**Low**
Regulating Reserves	Based on McReynold's 2000 estimate	13	9
Redispatch	Based on a load-based pro-rata increase in the 3 CCA redispatch benefits	55	40
Reliability	Based on a higher probability of avoided outages	21	10
Contingency Reserves	Based on full Henwood results (which had been de-rated for 3 CCA analysis)	25	17
	TOTAL	**114**	**76**

Unquantified Risks

The risks cited below are arranged into common groupings. They derive from several sources, including risks identified in the RRG's Risk Reward report.

Potential for Transmission-centric Planning.

Risk: This is the risk that Grid West, as a transmission entity, will bias the region towards transmission solutions to problems that may be better addressed by generation solutions.

Response / GW Controls:
- The GW planning/expansion model proposes an economic framework for investment decisions.
- GW will have no interest in financing transmission assets to increase its rate base. This reduces the risk of transmission-centrism as compared with the status quo.
- GW planning tools will model the entire electrical system – generation, load and transmission, giving it the capability for a holistic look at problems.
- The real time balancing service will reveal clearer congestion relief values than today – aiding in understanding the trade-offs between redispatch costs, generation construction costs, DSM costs, and transmission costs.
- This is an existing risk today, not incremental.

Bias toward Short-Term Solutions

Risk: Potential that Grid West might encourage increased reliance on short term markets – leading to greater volatility in power costs and rates.

Response / Grid West Controls:
- GW design provisions preserve and bolster existing long term bilateral markets.
- Participation in ST markets is voluntary.

Conservatism in Operation

Risk: Incentives to ensure reliability might result in Grid West operating the transmission system based on conservatively estimated limits. The flowgate methodology may encourage conservative grid management that protects TO's and minimizes complications for GW at the expense of customers.

Response / GW Controls:
- This is no more a risk than it is today. TO's already operate conservatively due to the high priority placed on reliability, and due to a lack of information about the system as a whole. That information problem should actually be solved by GW.

Lack of True Independence

Risk: That “focused economic interests”, large utilities, will capture the Grid West process at the expense of smaller, financially limited parties such as consumers and small utilities (as per theories by Stiegler and Peltzman).

Response / Grid West Controls:

- PNW has a long tradition of public involvement and advocacy organizations.
- A 2004 BPA commissioned report by National Association of Public Administration concluded that the GW bylaws “establish accountability to regional interests while maintaining independence of the governance structure from special interests.”
- See Appendix 5 for further discussion.

Cost Shifts

Risk: Structural changes in power and transmission markets are likely to shift wealth due to:

- Changes in transmission cost recovery
- Shifts from region to region due to increased market access
- New and different incentives for generation transactions
- Changes in transmission rate design, e.g. segmentation.

Response / Grid West Controls:

- Every effort has been made in market design process to minimize cost shifts. An ongoing mantra has been “honor all existing contracts”
- De-pancaking is limited to new contracts.
- Voluntary participation in balancing markets means that participants will have control over the impact of the new markets on themselves – if they stand to loose, they won’t participate.
- The Decision Point 4 analysis will address the issue of cost shift impacts in detail.

Erosion or Extension of Existing Transmission Rights

Risk: Grid West might cause the reinterpretation, or even abrogation, of existing contracts.

Response / Grid West Controls:

- GW developers have focused on preserving existing contracts and have taken every precaution to assure the continuation of existing rights.
- A recent FERC declaratory order stated that it will honor the region’s intention to preserve existing rights and will not attempt to abrogate any existing contracts.

Market Power

Risk: Competitive real time markets might create or exacerbate market power abuse.

Response / Grid West Controls:
This risk is well hedged in the Grid West design. It provides the following protections or improvements over existing systems:

- The real time markets are limited in scope – they only serve the balancing needs of voluntary control area consolidators – so opportunities to exploit the markets are limited.
- The design supports the continuation of existing dependence on long term bilateral contracts, leaving little to be manipulated in real time markets.
- The more transparent real time markets provided by Grid West reveal prices and make market monitoring easier to accomplish.
- The GW design includes a market monitor independent from any commercial interest.

Market Mismanagement

Risk: GW might take actions that impede efficient operation of the market place and lead to generation that is more expensive than it is today.

Response / Grid West Controls:

- GW Market and Operational Design is substantially different from the retail access models adopted by CA or the East Coast.
- GW is independent of any commercial interest.

New Opportunities for Inappropriate Gaming.

Risk: That the absence of a physical rights requirement in real time coupled with the requirement for physical rights in day-ahead markets will lead to arbitrage between the two markets – customers may attempt to circumvent the advance rights requirements by gaming the real time market.

Response / Grid West Controls:

- Balanced Schedule Requirement
- Intent to insert detailed provisions that will prevent this

Lags in Market Participation due to Transition Risks:

Risk: That many customers will take a ‘wait and see’ attitude before actively participating in new markets. They might wait for a year or two or three until the success of the Grid West operations is clearly established .

Response / Grid West Controls:
Grid West's incremental approach to development should hedge against this risk.

Increased Likelihood of Outage During Transition:

Risk: During the transition period, as Grid West brings new systems and people on line, there will be a higher probability of system failure.

Response / Grid West Controls:

- GW and TO operations will remain redundant initially – if not far into the future (BPA's utility level cost estimate reflects this in estimate a net increase, not decrease, in staff)
- GW will phase in new operations.
- To the extent possible, existing facilities, people, and systems will be used for Grid West operations.