FINAL REPORT

Study of Costs, Benefits and Alternatives to Grid West

Prepared for:
Snohomish County Public Utility District

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

Henwood Energy Services, Inc. (Henwood) was engaged by Snohomish County Public Utility District (Snohomish) to study the costs, benefits and alternatives to forming a new regional transmission organization in the Northwest, currently referred to as Grid West. This report details Henwood's analysis methodology, results and recommendations.

Grid West is a proposed regional transmission organization with a geographic footprint that would include the U.S. Pacific Northwest, British Columbia, Utah and parts of Wyoming, Nevada and Montana.[1] In response to the Federal Energy Regulatory Commission's (FERC's) Order 2000, the formation of Grid West has been under consideration by a coalition of transmission owners within the Grid West footprint since March 2000, with some involvement by the province of Alberta as well.

Henwood's approach to this report includes these topics:

- Review cost experience of existing RTOs;
- Review RTO status in the Northwest;
- Identify what elements can be modeled in a benefit/cost study, perform analysis, and compare results to earlier benefit/cost study performed by Tabors Caramanis & Associates;
- Identify possible unintended consequences resulting from RTO formation; and
- Examine transmission issues in the Northwest today and ways to address these without forming an RTO.

Cost Experience of Existing RTOs.
In 2004, an estimated $1.04 billion will likely be spent funding the operation of six RTOs – California ISO, NYISO, PJM, MISO, ISO-NE and ERCOT. Since 2000, total U.S. RTO operating expenses have increased by 143 percent and are growing at an annualized rate of 20 percent per year, largely due to increases in operational size and scope. This data shows that the start-up and operational cost trends for RTOs are significant factors in the determination of an RTO's net benefits or costs.

For this report, Henwood has relied on a recent analysis of these matters prepared by Margot Lutzenhiser, formerly of the Public Power Council (PPC). As the numbers above reflect, Ms. Lutzenhiser's work shows a clear and substantial upward trend in the operating costs of each of the nation's RTOs. We have taken these costs, along with their history of escalation, into account when analyzing the potential net impact of Grid West.

[1] There are many definitions of the Northwest. For purposes of this report, the Northwest shall be the geographic area defined by Public Law 96-501 (the states of Washington, Oregon, and Idaho, and parts of Montana and fringes of Wyoming, Utah and Nevada). When we refer to Grid West or Northwest Power Pool areas (which are defined elsewhere in the document) we will refer to them by name.

RTO Status in the Northwest Power Pool Area

The formation of RTO West/Grid West has been under consideration by a coalition of transmission owners within the Grid West footprint since March 2000.[2] As a result of significant regional dispute, the RTO West effort was put aside in the summer of 2003, and a modified approach (Grid West) was initiated in late 2003. The Grid West design was put forward as a new direction and fresh approach to dealing with the region's transmission problems and opportunities, while still building on, refining and incorporating some of the elements of the initial RTO West effort. Over the past few months there has been an effort to draft both Developmental and Operational Bylaws for Grid West. At the same time, a risk/reward group has been established to perform preliminary risk/reward (cost/benefit) analysis prior to seating of a Developmental Board. Both of these efforts are still ongoing.

The question of whether the draft Developmental Bylaws should be adopted by the current Grid West board of directors is scheduled to be taken up on November 4th, 2004. In the absence of any current or complete analysis of the benefits and costs of the Grid West proposal, and in light of the recent RTO operating cost data gathered at PPC, Snohomish engaged Henwood to fill this gap and to study the benefits and costs of an RTO in the Northwest.

Henwood's Grid West Benefit/Cost Study

Henwood's initial efforts included a review of previous RTO benefit/cost studies, focusing mainly on the study performed by Tabors Caramanis & Associates ("Tabors Caramanis" or "Tabors") in 2002 during the RTO West Stage Two deliberations, to identify commonly analyzed study parameters. These parameters are noted in the following table:

Table ES- 1
Potential RTO Costs & Benefits

Potential RTO Benefits	Potential RTO Costs
Pancaked rates eliminated Operating reserve requirements met more efficiently Better maintenance coordination (Gen & Tx) Existing transmission capacity more fully utilized Improved congestion management Increased reliability Transmission planning based on regional look Provision of market monitoring	Start-up costs Operating costs Escalation rates for operating costs Individual utility costs Qualitative costs

Using these general study parameters as a guide, Henwood analyzed the net impacts to the region as a whole of moving from today's environment to an end state where a regional transmission organization is in place and operating.

[2] Earlier efforts were also undertaken to examine the desire to have an independent system operator (IndeGO).

Henwood's review of the Northwest regional transmission system and the proposed Grid West end state revealed the following set of assumptions[3] as applied to the common RTO study parameters and as compared to the recent Tabors study:

Table ES- 2
Comparison of Henwood and Tabors Study Assumptions

	Henwood Study Assumptions		Tabors Study Assumptions	
Study Parameters	**Status Quo**	**End State**	**Status Quo**	**End State**
Pancaked Wheeling Rates	For majority of transactions, no incremental transmission rate charges.	Any existing pancaking for wheeling rates eliminated.	Pancaked rates apply when moving power from generation in the East to loads in the West.	Any existing pancaking for wheeling rates eliminated.
Operating Reserve Requirements	Each control area meets its own reserve requirements (as tempered by a reserve sharing agreement) without being able to call upon economic, but unused, capabilities from other control areas. Each control area can utilize its contract hydro supplies. Hydro spinning reserve capability may be fully utilized.	Most control areas are voluntarily combined such that all capabilities within the combined area are economically available.	Each control area meets its own reserve requirements without being able to call upon economic, but unused, capabilities from other control areas. Control areas are not able to use their contract hydro supplies. Hydro spinning reserve capability is limited.	Most control areas are voluntarily combined such that all capabilities within the combined area are economically available.
Gen & Tx Maintenance Coordination	Actual generation maintenance history used.	Actual generation maintenance history used (model revealed this was the optimized schedule).	Generation maintenance schedule around individual control area load patterns.	Modeled optimization of maintenance based on the combined area.
Transmission Capacity Allowed Utilization	Based on actual allowed utilization limits.	Increase allowed utilization, not to exceed WECC rated amounts.	Based on actual allowed utilization limits.	Based on actual allowed utilization limit.

[3] This list covers the key input assumptions and differences. More detail is available in the complete report.

Each of these assumptions will be discussed in more detail in Sections 1 and 3 of this report. However, a few comments about some of the significantly different assumptions are warranted here.

Henwood sees the system operation today as being much more efficient than does Tabors Caramanis in the following three areas:

a) **Transmission rate pancaking**. The Tabors Caramanis modeling approach assumed that there are pancaked rates when moving power from generation in the East to loads in the West. From an hourly dispatch point of view, this is simply not true. As Section 2.3 will explain, most transmission service in the Northwest is based on fixed fee type contracts that do not influence hourly dispatch decisions. 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. This does not happen very often today. However, in a "with RTO" case this would not happen at all, so in that case there may be savings in improved dispatch with an RTO.
b) **More efficient meeting of reserve requirements**.
    a. Tabors did not make available to control areas the hydro spinning reserve capability to which those control areas have contract rights. Henwood modeling reflects the fact that control areas do in fact use the reserve capabilities available in their long term contract rights.
    b. Tabors did not allow unused hydro to be fully counted toward reserve requirements. Henwood assumed that unused hydro can be fully used to meet reserve requirements if necessary. Henwood assumed further that the quantity of reserves that each control area needed to be held was determined through the Northwest reserve-sharing agreement and was limited to the 5%/7% criterion, not the maximum single contingency outage.
    c. Tabors assumed that without the RTO, each control area would need to meet its own control area reserve requirements without being able to call upon economic, but unused, capabilities from other control areas. While Henwood believes that control areas do engage in short term bi-lateral contracts today to call upon economic, but unused, capabilities from other control areas, for this study Henwood assumed that this was not being done.[4]
c) **Generation Maintenance Scheduling.** Tabors assumed that without an RTO, each of the many control areas that exist in the Northwest today would perform some analysis of control area loads in isolation and then schedule generation maintenance around those load patterns, irrespective of conditions in power markets. By doing this, the Tabors Caramanis process yielded

[4] Henwood is aware that short term bi-lateral contracting is done from time to time when certain control areas are in need of economic sources of reserves. However, Henwood does not have information on the extent of this type of bi-lateral contracting that occurs today. Therefore, Henwood conservatively assumed it was not happening at all for purposes of this study.

thermal generation maintenance occurring in summer months when WECC power markets are expected to have the highest prices. Henwood's approach was to look at when thermal maintenance is actually being scheduled today and then allow the model to optimize the scheduling of thermal generation maintenance from a single control area standpoint. Henwood could not find a computer optimized schedule that provided better maintenance scheduling than those maintenance schedules occurring today. Therefore, Henwood incorporated historical maintenance scheduling patterns in both the Base Case and With Grid West case, since the historical maintenance schedule appeared virtually identical to the optimal maintenance schedule.

In addition, Tabors erroneously counted the reduction in some costs assigned to load-based transmission rates as true gains in economic welfare rather than changes in transfer payments. Henwood corrected for this by simply calculating the change in Grid West generation cost between the with and without RTO state. Henwood did need to adjust for increases in generation in Grid West in the with RTO state. This adjustment involved applying an appropriate price to the increased export and then crediting the total to the change in power cost. The Henwood approach eliminated the analysis of transfer payments and only counted benefits or costs that represent true gains in economic welfare for the entire region. We estimate that Tabors erroneously counted $157 million in transfer payments (WECC-wide) as economic benefits in their analysis of RTO West. This estimate is the difference between the change in congestion rents and the change in production costs.

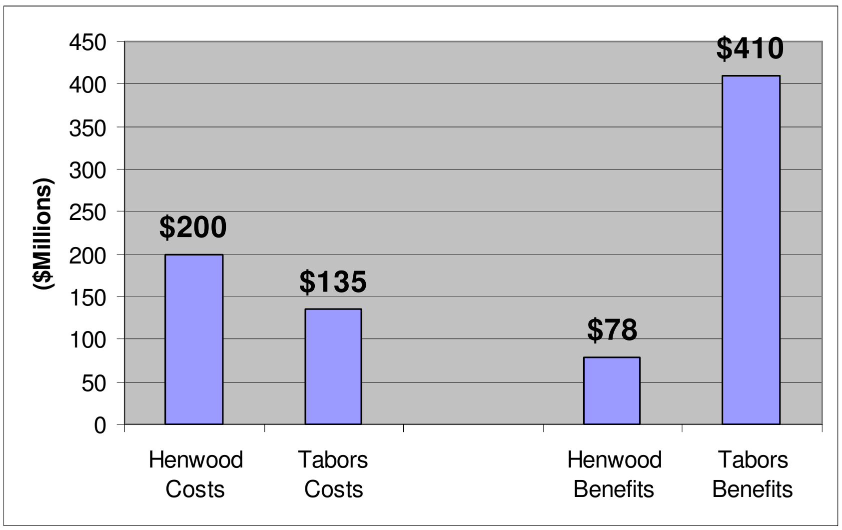
Largely as a result of these major differences in assumptions, Henwood has calculated benefits of only $78 million per year from formation of an RTO in the Northwest.[5] This compares to Tabors Caramanis' estimated benefits of $410 million per year.

In addition, both Henwood and Tabors attempted to estimate the costs associated with RTO operations. Applying the 2004 weighted average carrying costs of the nation's existing RTOs to Grid West's projected annual demand produces an estimated annual revenue requirement for Grid West of $184 million per year in 2004. Adjusting this operating cost number for actual growth trends experienced by existing RTOs, Grid West's projected annual revenue requirement could increase to $221 million per year by 2006. Given that Tabors Caramanis did not have as complete a cost history at the time of their study, the Tabors operating cost estimate was based on a much lower weighted average carrying cost and only amounted to $135 million for Grid West.

[5] The $78 million is made up of $73 million caused by assumed efficiencies gained by sharing operating reserves. The $73 million operating reserve benefit assumes that control area operators are not performing short term bi-lateral contracting for ancillary services when needed to meet its control area reserves. Henwood knows that some such contracting is happening today, therefore this benefit is overstated. In the extreme, if control areas enter into short term contracts today every time they are in need, then this estimated $73 million benefit would be reduced to zero.

In summary, where Tabors calculated net benefits of RTO formation, Henwood shows an annual net cost of approximately $122 million due to RTO formation [an average of $200 million in annual costs less $78 million in annual benefits]. Henwood believes that this $78 million in benefits is generous given the assumption we made that control areas are not making economic short term reserve-associated short term bi-lateral contracts today. Further, these figures are based on the assumption that the alternative to Grid West is the status quo. If alternative institutions and/or agreements are reached to overcome some of the regional problems, the benefits resulting from forming Grid West will be reduced even further.

Figure ES- 2
Comparison of Henwood and Tabors Costs & Benefits



Other Potential Benefits and Costs

One can estimate a number of other possible benefits and costs of RTO formation. While some may argue that there would be fewer large power outages under an RTO, others can point to examples where the existence of an RTO seems to have contributed to, or at least done little to mitigate, failures of the power and transmission system. For example, the catastrophic outage experienced on August 14, 2003 by the Midwest and Northeast that interrupted approximately 61,800 MW of load and affected an estimated 50 million people occurred in an established RTO environment. The Midwest ISO was charged with monitoring the system to ensure such outages did not happen. It has been stated that this outage was an unlikely combination of a number of events and that it would be highly unlikely for such a combination to occur again. Nevertheless, it is instructive to note that the events and outage occurred under an environment where MISO had been formed to help protect against such outcome. Another example of a large outage that occurred in an RTO environment is March 8, 2004 under the aegis of the California ISO. On that date the California ISO gave instruction for Southern California Edison to shed load for 20 minutes from 6:30 PM to 6:50 PM. The power outage affected about 70,000

SCE customers. After a fact finding investigation, the California ISO determined that this curtailment was caused by errors made by its operators.[6]

Numerous examples can be drawn upon to make statements about whether RTOs actually increase or decrease outages and subsequently increase or decrease costs to ratepayers. The bottom line is that we must keep the risk of unintended consequences in mind when weighing the benefits and costs of a proposed RTO.

Ways to Address Existing Transmission Problems Without Forming an RTO

Chapter 9 of this report identifies and discusses a number of problems associated with the Northwest transmission grid today. Some of the problems can be considered highly problematic; others are less so. The following list represents several of the transmission issues identified by the Northwest's key stakeholders:[7]

- Transmission rate pancaking;
- Multiple transmission queues for long-term service and generation interconnection;
- Need for better regional transmission planning, reliability, and security;
- No single OASIS and no single point of information on available transmission capacity (ATC);
- Differences between contract-path ATC and flowbased capacity that leave capacity unavailable; and
- Transmission rights clarity.

Chapter 10 of this report goes on to suggest a number of ways these existing problems can be addressed without the need to form a new organization. It only takes the resolve of the key players to solve the problems.

Conclusion

The Northwest is unique in that about 75 percent of the region's transmission is owned by one entity, BPA. Largely as a result of this singular situation, the analysis conducted by Henwood indicates that the costs of forming and operating an RTO in the Northwest will likely exceed the benefits. Moreover, there appears to be significant risks and unquantifiable costs associated with RTOs that the region should consider prior to moving forward with any proposed RTO structure. There are good reasons to address current transmission problems today, but this report suggests that the focus should be in those areas rather than in an effort to form an RTO. Resolution of these immediate problems today will likely provide more benefits to residents of the Northwest than will an effort to form an RTO.

[6] See CAISO press release dated March 15, 2004.
[7] There is not consensus among stakeholders that each item on this list is currently a problem.

1 BACKGROUND

1.1 Background on the Proposed Grid West

Grid West is a proposed regional transmission organization with a geographic footprint that would include the U.S. Pacific Northwest, British Columbia, Utah and parts of Wyoming, Nevada and Montana. In response to the Federal Energy Regulatory Commission's (FERC's) Order 2000, the formation of RTO West/Grid West has been under consideration by a coalition of transmission owners within the Grid West footprint since March 2000, with some involvement by the province of Alberta as well. At present, the following utilities comprise the Filing Utilities of the proposed Grid West: Avista Corporation, Bonneville Power Administration, British Columbia Hydro and Power Authority, Idaho Power Company, Nevada Power Company, NorthWestern Energy (formerly Montana Power Company), PacifiCorp, Portland General Electric Company, Puget Sound Energy, and Sierra Pacific Power Company.

As proposed, Grid West would be formed as an independent agency with operational authority of the transmission grid within the RTO footprint, responsible for tariff administration and design, congestion management, ancillary services, operating forward and real time markets, market monitoring and transmission planning/expansion. Grid West is a new, modified approach that was initiated in late 2003 and early 2004, taking the place of RTO West. The new Grid West design builds on, refines and incorporates some of the elements of the RTO West effort. Grid West is in its early stages of discussion, and over the past few months there has been an active effort to draft both Developmental and Operational Bylaws for Grid West. At the same time, a risk/reward group has been established to perform preliminary risk/reward (cost/benefit) analysis prior to the seating of a Grid West Developmental Board. This effort is still ongoing.

1.2 Snohomish Board Resolution

The question of whether the draft Developmental Bylaws should be adopted by the Grid West board of directors is scheduled to be taken up on November 4th, 2004. In the absence of any current or complete analysis of the benefits and costs of the Grid West proposal, and in light of the recent RTO operational cost data gathered at PPC, on June 15, 2004, the commissioners of Snohomish County PUD passed a resolution directing Snohomish management to engage the services of a Consultant to prepare a detailed Report on the Costs, Benefits and Alternatives to a Regional Transmission Organization of the type likely to be created and called Grid West. Henwood Energy Services, Inc. was engaged by Snohomish to perform this study. As part of that study Henwood was directed to review and comment on past benefit/cost studies. In particular, Henwood was asked to assess the results from the 2002 Tabors Caramanis study and compare Henwood's findings to those of Tabors Caramanis. This report documents Henwood's study methodology and findings.

1.3 General Approaches used in RTO Benefit/Cost Studies

In general, the valuation of benefits and costs of an RTO is achieved by assessing the electric market in a world with the RTO (the "With RTO Case") and comparing the With RTO Case to the status quo or current electric market without an RTO (the "Base Case"). If the costs associated with the creation and operation of the RTO are less than the benefits, the RTO can be said to be beneficial. The potential benefits to RTO formation commonly studied include:

- Elimination of pancaked rates;
- More efficient management of RTO-wide operating reserve requirements;
- Regional coordination of generation and transmission maintenance;
- Optimization of transmission grid utilization;
- Improved management of congestion on the transmission grid;
- Improved reliability; and
- Provision of market monitoring.

The costs associated with the formation of an RTO are generally broken into two categories: start-up costs and operating costs. Start-up costs include new buildings, infrastructure, software and the formation of rules and procedures. Operating costs are associated with operation, maintenance and administration of the RTO. Related topics that are often considered when estimating RTO costs include escalation rates (for operating costs), the impact of the RTO on individual utility costs, and other qualitatively analyzed cost implications.

1.4 Summary of Past Benefit/Cost Studies of Centralizing Transmission Control in the Northwest

Since utilities in the Northwest began considering an RTO type arrangement in the Northwest, three studies have been performed in order assess the benefits and costs of a Northwest RTO. These studies are summarized below.

1.4.1 IndeGO Benefits Report

This report was performed in early 1998 by a subset of the parties involved in the discussion of forming an Independent Grid Operator (IndeGo). The report itself indicated considerable differences in opinion among members of the IndeGO steering committee regarding the reported figures. The study focused on nine areas of potential benefits:

- Reduced staffing;
- Elimination of multiple control centers;
- Coordinated transmission planning;
- Elimination of pancaked transmission services;
- More competitive power markets;
- Improved reliability;

- Coordinated unit commitment;
- Coordinated maintenance; and
- Improved loss methodology.

The IndeGO report only attempted to quantify the benefits from the first four listed areas. The reported (and apparently disputed) benefits were estimated to be as much as $102 million per year, consisting of:

- Reduced staffing - $14 million per year;
- Elimination of multiple control centers - $2 million per year;
- Coordinated transmission planning - $3-5 million per year; and
- Elimination of pancaking – Between $8 and $81 million per year.

The report appears not to have estimated what it would have cost to start and operate IndeGO.

1.4.2 RTO West Potential Benefits and Costs

This report was performed in the Fall of 2000 by certain parties involved in the RTO West discussions at that time. The study focused on:

- Regulation reserve savings;
- Reliability improvements; and
- Elimination of pancaked transmission services.

The report indicates that it was not possible for the study to produce reliable conclusions regarding savings that might result from the elimination of pancaked rates. The report indicated an estimated savings of $28 million per year from reductions in Regulation Reserves.[8] The report also indicated that reliability improvements could be in the magnitude of $33 million to $328 million.[9] Annual cost of the RTO was estimated to be $63 million per year.

1.4.3 Tabors Caramanis & Associates Study

In March 2002, Tabors Caramanis performed its RTO West Benefit/Cost Study, which attempted to provide RTO West stakeholders an independent quantitative and qualitative analysis of the relative merits of an RTO in the Northwest. This study is examined in more detail in Section 1.5 below.

[8] Regulation reserves were assumed to be reducible as a result of load diversity. The report simply assumed that the cost of the reserves (prior to RTO formation) incurred by utilities was the posted BPA rate for this service. The study did not attempt to determine what costs utilities were actually incurring in providing their regulation reserves.

[9] This range of benefit was developed from an assumption that RTO West could prevent one 78 minute outage affecting the RTO West load once every 10 years. Such an assumption is suspect, because, for example, there has been no major outage in the northwest since 1996, and it is not at all clear that having fewer operators watch the system would have avoided the last two major outages in WECC in 1996.

1.5 Tabors Caramanis General Approach

Tabors Caramanis' approach to test the impact of the formation of the proposed RTO West was to perform and compare WECC-wide market simulations of two scenarios: 1) the current market structure, Without RTO, and 2) With RTO. Tabors used the GE MAPS simulation tool. The analysis was performed for the year 2004. Tabors assessed the benefits and costs of the proposed RTO West using both the production cost method and the social welfare method (Tabors measured producer and consumer surplus). Tabors' analysis quantified the possible economic benefits of Grid West from the following:

- Elimination of pancaked transmission wheeling rates;
- Elimination of pancaked transmission loss charges;
- Access to a broader market for operating reserves;
- More efficient, regional utilization of generation resources; and
- Increased scheduling efficiency of transmission capacity (through reduced requirements for contract path scheduling limits).

1.5.1 Treatment of Wheeling Rates and Losses

Tabors stated that where pancaked wheeling rates and wheeling losses exist, their elimination can increase the economic efficiency of dispatching generation resources to meet demand and, in doing so, lower the total cost of producing electricity within the RTO. In Tabors' With RTO case, Tabors eliminated pancaked transmission wheeling rates for transactions that cross more than one control area within the RTO topology, replacing pancaked wheeling rates with a single, RTO-wide wheeling rate. Tabors also eliminated pancaked wheeling loss charges in the With RTO case, replacing them with a single wheeling loss rate.

1.5.2 Treatment of Operating Reserves

Tabors Caramanis assumed in the With RTO case that RTO-wide management of the operating reserves would be more efficient than in the Without RTO case, thereby leading to lower operating costs. With more generation sources available to meet reserve requirements, reserves can potentially be obtained from cheaper resources, such as a large hydro generation unit, rather than more expensive thermal units that an individual control area, required to meet its reserve requirements on its own, might be forced to use.

Tabors Caramanis assumed that without the RTO, each control area in the Northwest would meet its own control area reserve requirements without being able to call upon economic, but unused, capabilities from other control areas. In performing their analysis, Tabors Caramanis did not make available to control areas the hydro spinning reserve capability to which those control areas have contract rights.

1.5.3 Coordination of Maintenance Schedules

Tabors Caramanis also states that an RTO can improve efficiency and lower operating costs by improving the coordination of generation and transmission asset maintenance schedules. Tabors assumed that without an RTO, each of the many control areas that exist in the Northwest today would perform separate control area loads analysis and schedule generation maintenance around those load patterns.

1.5.4 Increased Availability of Transmission Capacity

Increased availability of transmission capacity is mainly due to the elimination of the Capacity Benefit Margin and the Transmission Reserve Margin, better scheduling of transmission line maintenance, and the elimination of contract path contracts and scheduling limits.

1.5.5 Other Economic Benefits

Tabors Caramanis discussed several other potential benefits of an RTO qualitatively. They are:

- Congestion Management. The real-time management of power flows across the transmission system, charging for transmission congestion and losses on a marginal basis, is assumed to be an added function of an RTO. It is assumed that managing congestion on the transmission system this way will increase utilization of the transmission system and improve efficiency. Tabors assumed that congestion would be economically managed in both cases.
- Increased Market Competitiveness. Tabors states in its report that "Establishing regional transmission operators and a single tariff, standardized rules and procedures, transparent market clearing prices and operation, increases the competitiveness of electric power markets by reducing transmission costs associated with moving power from sources to load, and the transaction costs, thus increasing the economic deliverability of generators." Tabors did not attempt to separately quantify such a benefit.
- Coordination of system expansion and planning. In a market where greater competitiveness and independent power assets play a key role, coordinated regional transmission expansion and planning become more important.
- Adopting a single OASIS site. The proliferation of OASIS sites by control area and the use of different technologies used at each site make trading electricity a difficult task, increase transaction costs and disadvantage smaller players. A single RTO-wide OASIS will likely resolve these issues.
- Improved reliability on regional basis. The sharing of real-time and maintenance information on transmission and generation systems increase the capability of operators to properly avoid outages and respond to outages if they occur.

1.5.6 Costs of an RTO

Tabors Caramanis' estimation of start-up and operating costs was based on extrapolations of start-up and operating cost information from other RTOs/ISOs in the U.S. and Canada.

1.5.7 Critique of Study Approach and Results

Henwood finds that the Tabors Caramanis study is sound in its scope of analysis and methodology, but erroneously assumes that the Northwest electric system today is operated much less efficiently than it actually operates, especially in the areas of pancaking, operating reserve requirements, and generation maintenance. In addition, recent information has revealed that Tabors underestimated the potential operating costs of an RTO in the Northwest.

1) Transmission Rate Pancaking. Tabors Caramanis erroneously assumed that numerous pancaked wheeling and losses charges impact every generation dispatch decision today. The Tabors Caramanis modeling assumes that there are pancaked rates and losses when moving power from generation in the East to loads in the West. From an hourly dispatch point of view, this is simply not true. For example, while Puget gets much of its generation to meet its King County, Washington area load from coal-fired generation located in Eastern Montana (Colstrip), Puget has put together transmission arrangements that do not yield wheeling charges that can be avoided by shutting down the plant. Puget's transmission payments are essentially fixed payments that do not vary with plant operation. Further, existing transmission contracts generally provide for a fixed loss percentage covering the entire transmission distance. With such transmission contracts, there is no incremental transmission rate charge and there is no significant amount of pancaking of the losses charge.

   Tabors assumed these contracts would have pancaked charges in the without RTO case, while Henwood reflected the fact that most transmission service would not involve pancaked charges. Only in certain conditions (when BPA paths are full and other non-BPA facilities must be used) does Henwood's analysis reflect pancaked transmission rates and losses. This does not happen very often today. However, in a "with RTO" case this would not happen at all, so in that case there may be savings in improved dispatch with an RTO. Nevertheless, Henwood's analysis shows this to produce much lower savings than does Tabors' analysis.

2) More Efficient Meeting of Reserve Requirements. Tabors Caramanis erroneously assumed individual control areas that exist today do not have access to their contract hydro supplies to meet reserve requirements, and they erroneously assumed that these control areas do not count all their hydro as available to meet reserve requirements. Tabors Caramanis assumed that without the RTO, each control area in the Northwest would need to meet its own control area reserve requirements without being able to call upon economic, but unused, capabilities from other control areas. In performing their analysis, Tabors Caramanis did not make available to control areas the hydro spinning reserve capability to which those control areas have contract rights. For example, Portland General Electric has contract rights to certain

non-federal mid-Columbia hydro generation. Portland General Electric actually uses the spinning capability of these mid-Columbia projects to the extent of their contract rights. Tabors Caramanis erroneously assumed that Portland General Electric could or would not use those rights today. Further, Tabors Caramanis restricted the amount of spinning reserve available at hydro units to something less than what the units can actually provide.

Henwood corrected for those two erroneous assumptions. As a result, Henwood's analysis showed less benefit from RTO combination of control areas than did that of Tabors Caramanis. Henwood's calculated benefit may still be overstated because in today's world utilities will likely enter into short term contracts if necessary to meet their reserve obligations. However, since Henwood does not have information sufficient to allow it to model how much of this short term contracting is being done today, we have assumed that utilities are not using such short term contracting. This probably results in Henwood overstating the benefit of the RTO.

3) Generation Maintenance Scheduling. Tabors Caramanis erroneously assumed that generation maintenance is not being scheduled efficiently today. Tabors Caramanis assumed that without an RTO, each of the many control areas that exist in the Northwest today would perform isolated analyses of control area loads and then schedule generation maintenance around those load patterns. By doing this, the Tabors Caramanis process yielded thermal generation maintenance occurring in summer months when WECC power markets are expected to have the highest prices.

   Henwood's approach was to look at when thermal maintenance is actually being scheduled today and then allow the model to optimize the scheduling of thermal generation maintenance from a single control area standpoint. Henwood could not find a computer optimized schedule that provided better maintenance scheduling than those maintenance schedules actually occurring today.

4) Costs of Forming and Operating an RTO: Tabors Caramanis under-estimated the start-up and operating costs of forming and operating an RTO in the Northwest. Similar to the estimation of costs for this study, Tabors Caramanis' estimation of start-up and operating costs were based on extrapolations of start-up and operating cost information from other RTOs/ISOs. However, Tabors Caramanis' cost estimates were significantly less than the cost estimates calculated for this study. Tabors Caramanis estimated that the "carrying costs", defined as start-up and operating costs combined, for RTO West between \$0.45/MWh and \$0.51/MWh. Given Tabors' estimate of annual energy throughput for RTO West in 2004 (280 TWhs), Tabors calculated RTO West carrying costs at approximately \$127 million.

This is significantly underestimated based on today's RTO start-up and operating cost information. Margot Lutzenhiser, formerly of the Public Power Council, has estimated the weighted average start up costs of existing RTOs to be between \$0.52/MWh and \$0.70/MWh. Multiplying the weighted average start-up cost estimates by the annual throughput of Grid West (estimated at approximately 250 TWhs for this study), Grid West start-up costs were estimated to be between \$133 million and \$177 million. Operating costs for existing RTO's were estimated at a weighted average \$0.73/MWh in 2004. Based on Grid West's annual energy throughput, Grid West's annual operating costs are estimated to range between \$184 million/year and \$221 million/year (based on a 20 percent escalation per year for two years). Henwood expects that Tabors' under-estimation of costs results from the use of older cost data that does not reflect the significant increase in RTO scope and expenses that has occurred since 2000. Since 2000, total U.S. RTO expenses have increased by 143 percent and RTOs have been growing at an annualized rate of 20 percent per year, largely due to changes in operational size and scope. The RTO cost analysis for this report is provided in Section 5.1.

1.6 Henwood's Benefit/Cost Analysis Methodology

Henwood's approach to studying the benefits and costs of the proposed Grid West was performed in a manner similar to other benefit/cost studies. Henwood focused on comparing the benefits and costs of two cases: 1) the status quo or Base Case, which represents the market as it is today, and 2) the Grid West Case, a case that represents the "end state" where Grid West is formed and operating. Henwood has analyzed the year 2006. Henwood's study is a WECC-wide study with a focus on the proposed Grid West topology. Henwood used its MARKETSYM-LMP model to perform the quantitative analysis.

Henwood quantitatively studied the benefits and costs associated with parameters that are common among most RTO studies, including the Tabors Caramanis Study. The parameters studied, which are discussed in greater detail in the Quantitative Analysis Methodology section of this report (Section 3), are summarized below:

The potential benefits to RTO formation considered and studied by Henwood include:

- Elimination of pancaked transmission rates that adversely impact resource dispatch;
- More efficient management of RTO-wide operating reserve requirements;
- Better coordination of generation and transmission maintenance;
- Optimization of transmission grid utilization; and
- Improved management of congestion on the transmission grid.

The costs associated with the formation of an RTO considered in this report are:

- Start-up costs;
- Operating costs; and
- Escalation rates (for operating costs).

Impact on Individual Control Areas not Considered

The Henwood study focuses primarily on the net benefits across the proposed Grid West topology and does not explicitly assess the impacts an RTO may have on individual control areas or transmission owners. Henwood recognizes that the equitable allocation of benefits and costs is an issue that exists today under the current system, as well as the fact that the formation of an RTO may cause significant transfers of wealth between control areas, among marketers, and among consumers, producers and transmission owners. It should be pointed out that formation of an RTO does not necessarily solve allocation issues and, if not formed with the proper rules and procedures, could result in greater inequities. These are important issues that require further analysis and are beyond the scope of this study.

Alternatives to Grid West

A key component of this study, in addition to the quantitative benefit/cost analysis assessing the impact of Grid West, is to assess transmission and system management problems that exist in the Northwest today and identify potential alternatives for solving these problems without necessarily forming an RTO in the Northwest. The existing problems in the Northwest and alternatives for addressing those problems are addressed in Sections 9 and 10 of this Report.

2 THE NORTHWEST TODAY

2.1 The Northwest Transmission Grid

The two most common definitions of the Northwest are either the area served by the Northwest Power Pool (NWPP), or the area as defined by the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501 – Dec 5, 1980). The NWPP was formed in 1942, when the federal government directed utilities to coordinate operations in support of wartime production. Today, the NWPP serves as a forum in the electrical industry for reliability and operational adequacy issues in the Northwest, through both the transition period of restructuring and the future. NWPP promotes cooperation among its members in order to achieve reliable operation of the electrical power system, coordinate power system planning, and assist in transmission planning in the Northwest section of the Western Interconnection. It is a voluntary organization comprised of major generating utilities serving the northwestern U.S., British Columbia and Alberta. Smaller, principally non-generating utilities in the region participate indirectly through the member system with which they are interconnected. A number of these smaller entities are actually members of the NWPP. Also merchant/generator/user (non-wire owners) organizations such as TransAlta and Alcoa are Power Pool members.

The NWPP area is larger than the area defined by the Pacific Northwest Electric Power Planning and Conservation Act ("the Act"). Under that Act, the Pacific Northwest is defined as the area "consisting of the States of Oregon, Washington, Idaho, the portion of the State of Montana west of the Continental Divide and such portions of the States of Nevada, Utah, Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from the area referred to above, which are a part of the service area of a rural electric cooperative customer served by BPA on the effective date of the Act which has a distribution system from which it serves both within and without such region" In accordance with this definition, no Canadian land is considered part of the Northwest. Further, very little of the states of Wyoming, Utah and Nevada are considered part of the Northwest.

2.2 The Grid West footprint

The geographic footprint for Grid West is an uncertainty at this time. While it could include the entirety of the NWPP area, it also might be smaller than the Northwest area as defined by PL 96-501. Figures 3-2 and 3-3 show the area that is assumed to be in the Grid West footprint for purposes of this report. As indicated in the figures, the Grid West footprint is assumed to include British Columbia, but not Alberta.[10] Further, it is assumed that Nevada Power is not a part of the Grid West footprint.[11]

[10] While Alberta attends Grid West meetings, Alberta is largely electrically isolated from the Grid West footprint. Therefore, its presence or absence in the Grid West footprint being assumed for this study has

2.3 The Bonneville Power Administration – Transmission Business Line

BPA is a federal agency within the U.S. Department of Energy that markets electricity from 31 federally owned dams, one non-federal nuclear plant and several non-federal hydroelectric projects and wind energy generation facilities[12]. There are two main business lines within BPA—Power Business Line and Transmission Business Line. The Power Business Line (PBL) is BPA's power marketing arm, where the core role of the Transmission Business Line (TBL) is assuring the region has a safe and reliable electric grid, open and non-discriminatory business practices, and competitive rates. BPA owns and operates about three-quarters of the Northwest region's high voltage electric grid.[13] Its 15,000 miles of transmission and distribution lines carry power from the dams and other power plants to utility and industrial customers. Dispatchers coordinate and monitor power flowing throughout the Northwest as well as to other parts of the West, making sure that this complex, interconnected system runs smoothly.

Although the Northwest is home to a number of other utilities, including Pacific Power & Light, Portland General Electric, Puget Sound Energy, Avista, Idaho Power, part of Northwest Energy, Seattle City Light, Snohomish PUD, and Tacoma Power, most of the region's wholesale power is moved over transmission lines owned by BPA and subscribed to by the various utilities. Assuming that BPA has grandfathered transmission rights up to the nameplate capacity of the Federal Base System,[14] essentially all of the transfer capability of the BPA transmission grid, and hence 75 percent of the Northwest region's overall transmission, has been subscribed under long term contracts.

BPA's long-term transmission contracts are essentially fixed fee based (similar to the "license plate" arrangement proposed by Grid West), whereby a subscriber pays what amounts to a fixed fee, either annually or monthly, for the rights to use a certain amount

little if any effect on overall study results. For simplicity in modeling it was removed from the Grid West footprint.

[11] While Nevada Power is listed as a Filing Utility for RTO West, Nevada Power has little transmission connection with the Northwest. Sierra Pacific Resources owns both (a) Sierra Pacific Power (which has some measure of meaningful transmission intertie with the Northwest) and (b) Nevada Power (with essentially no transmission intertie to the Northwest). It is possible that Nevada Power is a sponsoring utility simply because its parent and sister utility are involved. The presence or absence of Nevada Power would have little if any effect on overall study results. For simplicity in modeling it was removed from the Grid West footprint.

[12] Collectively referred to as the Federal Base System.

[13] When it is stated that BPA owns and operates three quarters of the Northwest region's high voltage electric grid, the region is the northwest as defined by PL 96-501. If British Columbia, Utah and other Grid West geography outside of the PL 96-501 area is considered, BPA's share of the high voltage grid would be reduced.

[14] This assumption may be questionable because of the issue of underutilized capacity discussed in Section 9.

of transmission.[15] Fixed fee type charges for transmission rights generally do not impact generation dispatch decisions. The conclusion that can be drawn here, and that we have used for this study, is that the vast majority of Northwest generation owners do not take wheeling costs into consideration when making dispatch decisions.

While the transfer capability of the BPA transmission grid may have been fully sold, the transmission grid historically has experienced low usage on average over time.[16] The phrase "the BPA grid is 'oversold' but 'underutilized'" stems from the recognition that transmission rights seem to cover the entire BPA transmission grid, but the grid experiences low usage. The "oversold" aspect of this issue sometimes leads to a feeling that more transmission needs to be built by BPA, whereas the "underutilized" aspect of this issue counters that very same feeling.

In general many of the region's transmission rights are clearly defined in long-term contracts. However, many regional stakeholders believe that there is not enough clarity or transparency in how BPA manages portions of these transmission rights. Further, some stakeholders believe that BPA's congestion management policy is not as robust as needed.

2.4 Other Transmission Owning Utilities in the Northwest

Since BPA owns approximately 75 percent of the region's transmission, the multitude of other utilities in the region share approximately 25 percent of the transmission. The BPA lines are generally used for wholesale marketing, and as mentioned previously, the majority of that capacity has been subscribed under long-term contracts. The capacity of 25 percent of the lines (those owned by non-BPA entities) are generally used for more limited purposes specific to the owning utility and may not be fully subscribed under long term transmission commitments. These lines are occasionally needed for wholesale power transactions (e.g., if there is a parallel path to a fully utilized BPA line). When these non-BPA lines are needed, the owning utility may charge an hourly wheeling rate for the use of such lines. These hourly wheeling charges will likely impact generation dispatch decisions, and therefore we have included these charges in this study's dispatch modeling.

[15] Each of Point-to-Point (PTP), Formula Power Transmission (FPT), Network Transmission (NT), and Integration of Resources (IR) type transmission contracts are fixed fee. In the case of NT, the fixed monthly charge per KW is applied in such a fashion that it does not impact dispatch decisions**.**

[16] The low usage can be attributed to the fact that transmission reservation contracts are often determined by the nameplate capacity of hydro resources and the operating level of these resources is generally less than 50 percent capacity factor due to the limited fuel (water) availability for the units. The low usage can also be attributed to the fact that the Northwest generally has much more generation nameplate capacity than it has peak load since the region is energy constrained rather than capacity constrained.

2.5 The Pacific Northwest Security Coordinator

The Pacific Northwest Security Coordinator (PNSC) is a Washington non-profit corporation. The purpose of the PNSC is: (1) to provide security coordinator services to NWPP control area operators that enter into agreements with the PNSC; and (2) to engage in any lawful business relating or incidental to the provision of security coordination services. The security coordination services provided by the PNSC consist generally of monitoring, analysis, communications, advice, and when necessary, directives, for the purpose of helping to preserve the reliability of transmission service between and within interconnected electrical systems of the NWPP that enter into agreements with the PNSC. The PNSC is staffed so that it can perform its duties 24 hours per day, 7 days per week.

2.6 Open Access Transmission Tariffs and Open Access Same Time Information Systems

All owners of major transmission lines in the Northwest have developed (and made available to potential users of their transmission lines) an Open Access Transmission Tariff (OATT) in conformance with FERC guidelines for such OATTs. Pursuant to those OATTs, these parties also provide information on the availability of their transmission grids under an Open Access Same Time Information System (OASIS) – an internet-based source of information. As of the date of this report, many Northwest utilities are coordinating their OASIS information systems via a common web site called "wesTTrans.net." The wesTTrans OASIS system provides several important features for Transmission Customers, including multi-provider queries, an energy bulletin board, multi-provider deals, and resales. Extensions to these features and development of new features that improve productivity, enhance revenue opportunities, etc., are being openly discussed in the newly formed wesTTrans Focus Group.

2.7 Historical Congestion

While there are numerous cutplanes in the Northwest that have the potential of experiencing congestion (e.g., during very high hydro conditions), actual data indicates that there is little such congestion on these lines generally. The Seams Steering Group – Western Interconnect (SSG-WI) has most recently provided a report that demonstrates the historical lack of congestion in the Northwest.

3 QUANTITATIVE ANALYSIS METHODOLOGY

Henwood's analysis methodology for calculating the benefits and costs associated with the formation of Grid West can best be summarized as a comparison of the cost of production for two scenarios. The first scenario is the Base Case, which represents the status quo, without an RTO in operation. The second scenario is modeled to represent a future in which Grid West is in operation (the Grid West Case). For both cases, the analysis was performed for the year 2006.

3.1 Analysis Methodology

For this study Henwood simulated a network analysis, where network flows are determined using a security constrained unit commitment and dispatch analysis. Henwood's analysis goes beyond constraints typically included in zonal models—such as operating reserves, unplanned outages at generating facilities, and transportation-like representation of key regional transmission paths—to introduce additional constraints tied to a detailed description of the transmission network. These include transmission line and interface limits, and complex operating schedules tied to multiple interfaces.

Henwood's analysis approach relies on two widely accepted industry standard models, (a) the EnerPrise Market Analytics Module, MARKETSYM and (b) PowerWorld Simulator. Within the PowerWorld system rests the ability to compute network flows (and if desired, nodal prices subject to the transmission constraints that govern power system operations). The combined models and their associated databases are referred collectively as MARKETSYM-LMP.

A MARKETSYM simulation is used to develop desired hourly commitment of generators. The hourly dispatch and commitment data from that simulation, along with bid curves of the units, are passed to the accompanying detailed transmission network model. The network model utilizes the initial MARKETSYM zonal solution to test if any of the detailed network elements ratings and path ratings are exceeded with this MARKETSYM determined generation pattern.

Henwood modeled the year 2006 for this analysis. Henwood's analysis started with the 2006 year for WECC as reflected in Henwood Spring 2004 WECC Reference Case.[17] Henwood has reviewed the extensive list of projects that are being proposed in WECC. Based on the current status of project development and the reality of an existing overbuild of generation in WECC, Henwood assumes that only those plants currently under construction will come on line by 2006. The list of plants expected to come on line between 2004 and 2006 is included in Appendix B.

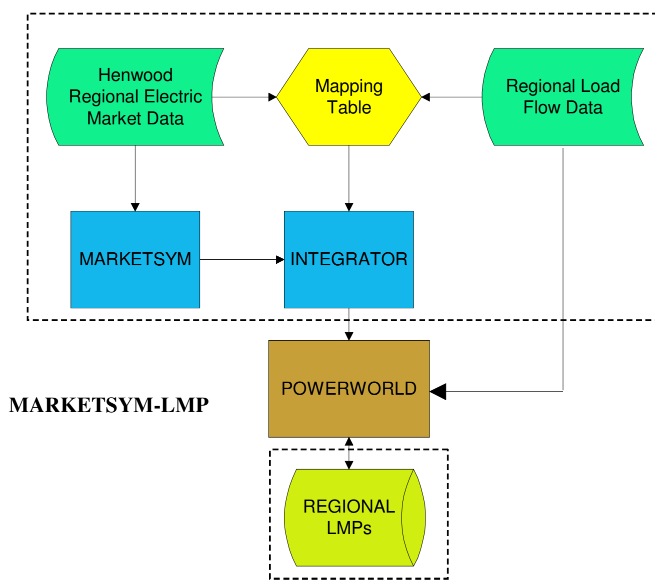
[17] Henwood publishes a new 25 year forecast "WECC Reference Case" every six months. The case is Henwood's independent view of power markets in WECC. Over 50 clients subscribe to the Henwood WECC Reference Case product. The forecast is used by clients for their own purposes and Henwood uses it in custom consulting assignments and when evaluating assets for banks, etc. when an independent forecast is needed for due diligence purposes.

The network simulation is capable of capturing the effect of loop flows and tests for congestion. If congestion is present across a given path, the network results will indicate a problem and generation dispatch patterns would need to be adjusted.[18] The MARKETSYM-POWERWORLD platform provides a complete solution to calculating optimal dispatch and network flows.

The workflow process employed by Henwood in the use of MARKETSYM-LMP[19] is shown in Figure 3-1. The workflow associated with the analysis can be best described as a two step process:

- First, the MARKETSYM simulation produces unit commitment and dispatch decisions that honor such important constraints as generator operating parameters, energy limited fuels (including hydro), inter-zonal transmission path constraints, and locational operating reserve requirements.
- Next, the initial MARKETSYM solution is passed into PowerWorld Simulator, properly configured subject to the initial solution conditions set in MARKETSYM as well as the transmission constraints represented in the network model.

Figure 3-1
MARKETSYM Nodal Workflow

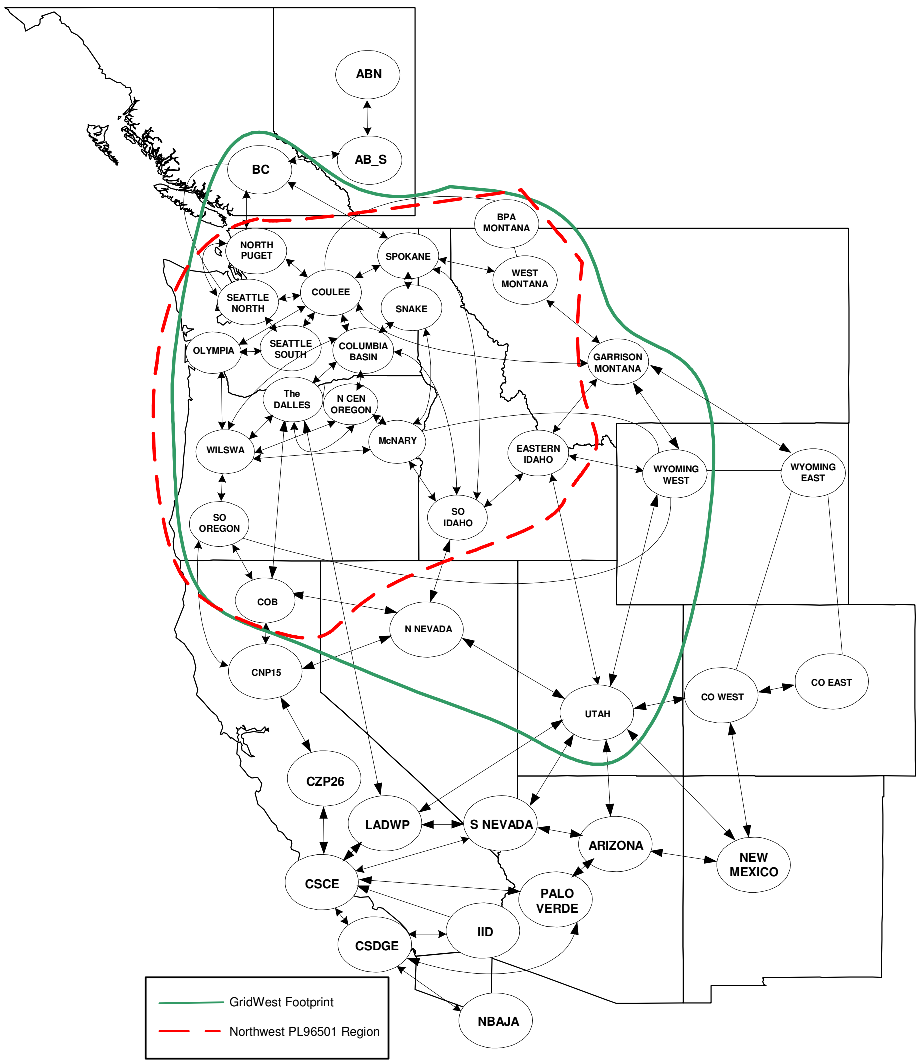


[18] Henwood found negligible incidence of line/path overloads when it ran the network model using MARKETSTM generation dispatch patterns
[19] Since Grid West is not contemplating using LMPs, Henwood did not use the LMP capability of PowerWorld, and instead simply used PowerWorld to ensure that network elements were not being overloaded by the MARKETSYM determined optimal generation dispatch.

3.2 WECC Topology

As illustrated in Figure 3-2, Henwood has divided the WECC into 39 different market areas (of which 22 market areas comprise the proposed Grid West geographic area) for purposes of modeling how power schedulers and traders deal with transmission constraints, wheeling costs and losses. This is called the zonal analysis. In the Base Case, there are certain wheeling costs in the Grid West footprint. In the Grid West Case, there are no wheeling costs in the Grid West footprint (only wheeling into and out of Grid West is reflected in the Grid West Case). For purposes of scheduler and trader decisions, losses are the same in both cases.

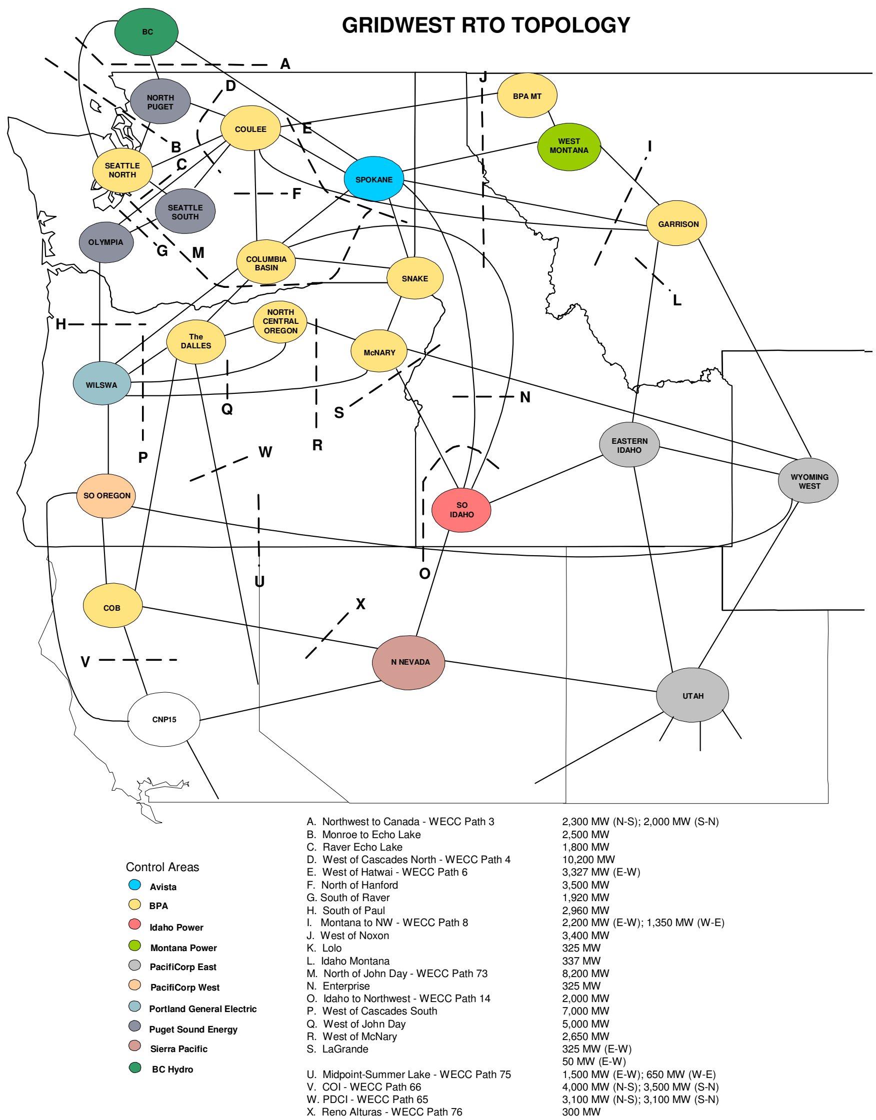
Figure 3-2
WECC 39 Zone Topology



3.3 Grid West Topology

Figure 3-3 focuses in on the Grid West portion of the WECC topology. In this figure we have also indicated the key cut planes and links between market areas that have been included in the analysis. The topology reflects both physical path ratings (dashed lines) as well as known contractual and physical links between market areas. Where contractual arrangements are known to exist between entities, links have been established in order to reflect their ability to wheel power without incurring pancaked wheeling rates. This is discussed in greater detail in Section 3.4 below.

Figure 3-3
Grid West RTO Topology



3.4 Pancaked Wheeling Rates

Wheeling charges are amounts charged by transmission owners for use of their transmission system. Wheeling charges are based on wheeling rates established in the transmission owner tariff (TO Tariff) and, along with other transmission charges, contribute to recovering the utility's transmission revenue requirement. A utility's transmission revenue requirement is a fixed amount that ensures the recovery of the costs associated with the construction, operation and maintenance of the transmission owner's transmission system.

The phrase "pancaked" wheeling rates refers to the payment of multiple wheeling rates for a single transaction across multiple transmission systems. Pancaked wheeling rates may apply to a series of short- or long-term contracts across the grid, each with its own fixed payments. Pancaked wheeling rates can also be applied as volumetric ($/MWh) rates that must be paid to a series of transmission owners across the grid. For this analysis, which is an analysis to see how pancaked rates impact generation dispatch, we are focusing only on those volumetric ($/MWh) rates. With the creation of Grid West, these volumetric pancaked wheeling rates, to the extent they exist, would be eliminated. However, a single "wheeling out" rate would be retained for transactions between Grid West and neighboring transmission owners/RTOs. Table 3-1 below provides a list of wheeling rates for each transmission owner used in this Analysis.

Table 3-1
Wheeling and Loss Rates across Key Cut Planes in the Northwest

	Wheeling [1,2]	Wheeling Back	Losses	Losses Back
Link Name	($/MWh)	($/MWh)	%	%
BC – Seattle North	6.3 (0)	2.96 (0)	6.05	1.96
BC – North Puget	6.3 (0)	.5 (0)	6.05	1.38
BC – Spokane	6.3 (0)	4.0 (0)	6.05	3.0
North Puget – Seattle North	.5 (0)	0	1.38	0.5
Seattle South – Seattle North	.5 (0)	0	1.38	0.5
Coulee – North Puget	0	.5 (0)	0.5	1.38
Coulee – Seattle North	0	0	0.5	0.5
Coulee – Olympia	0	.5 (0)	0.5	1.38
Coulee – Seattle South	0	.5 (0)	0.5	1.38
Spokane – Coulee	4.0 (0)	0	3.0	0.5
Spokane – Columbia Basin	4.0 (0)	0	3.0	0.5
Spokane – Snake	4.0 (0)	0	3.0	0.5
Garrison – Coulee	0	0	1.5	1.5
BPA Montana – Coulee	0	0	1.5	1.5
Coulee – Columbia Basin	0	0	0.5	0.5

	Wheeling [1,2]	**Wheeling Back**	**Losses**	**Losses Back**
Link Name	($/MWh)	($/MWh)	%	%
Seattle South – Olympia	0	0	1.38	1.38
Olympia – Wilswa	.5 (0)	1.25/.718 (0)	1.38	1.6
Garrison – West Montana	0	4.25 (0)	0.5	4.0
Garrison – Spokane	0	4.0 (0)	1.5	3.0
West Montana – Spokane	4.25 (0)	4.0 (0)	4.0	3.0
So Idaho – McNary	2.38/1.33 (0)	0	3.6	0.5
Eastern Idaho – Garrison	5.84 (0)	0	4.48	1.5
Columbia Basin – Wilswa	0	1.25/7.18 (0)	0.5	1.6
Columbia Basin – the Dalles	0	0	0.5	0.5
Columbia Basin – Snake	0	0	0.5	0.5
Columbia Basin – So Idaho	0	2.38/1.33 (0)	0.5	3.6
Wyoming West – So Oregon	0	0	1.9	1.9
The Dalles – Wilswa	0	1.27/.718 (0)	0.5	1.6
North Central Oregon – Wilswa	0	1.27/.718 (0)	0.5	1.6
McNary – Wilswa	0	1.27/.718 (0)	0.5	1.6
North Central Oregon – the Dalles	0	0	0.5	0.5
McNary – North Central Oregon	0	0	0.5	0.5
COB – CNP15	3.34 (0)	2.25 (0)	3.0	2.0
The Dalles – LADWP	3.34 (0)	2.25 (0)	8.0	8.0
COB – N Nevada	3.34 (0)	6.9/3.9 (0)	3.0	2.34
ABN – ABS				
ABS – BC				

Note 1: A "(0)" in a cell means that number is reduced to zero in the Grid West case.
Note 2: "2.38/1.33" means the rate is 2.38 during on peak hours and 1.33 during off peak hours.

In the Northwest, most transmission capacity is sold as "rights", either under firm long-term contracts or under shorter-term firm contracts (e.g., one month at a time). When transmission capacity is purchased under fixed contract rights (long-term or short-term), the dispatch of generation into the market is unaffected by the sunk costs of the transmission contracts. In these cases, the elimination of pancaked transmission rates would not reduce the cost of generation, but would instead shift the costs from one transmission owner to another (leaving the net impact at the Grid West level at zero).

There are some pancaked wheeling transactions within the Grid West topology that are not based on pre-existing "rights" and therefore might impact dispatch decisions. However, given the relatively small number of these transactions, their elimination would have little impact to the region overall.

3.5 Operating Reserve Obligations

The WECC has established Minimum Operating Reliability Criteria (MORC). Based on the WECC criteria, each control area must maintain a reserve that is at least the greater of 1) the sum of 5 percent of the load responsibility served by hydro generation and 7 percent of the loads responsibility served by thermal generation (at least one-half of which must be spinning reserve); or 2) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least one-half of which must be spinning reserve). However, WECC's operating reliability criteria are voluntary and there is no monitoring and enforcement of these obligations.

While the WECC criteria are voluntary in nature, members of the Northwest Power Pool have signed a Reserve Sharing Agreement (RSA) that creates a contingency reserve obligation combined with a pro-rata reserve sharing system. Under the RSA, NWPP members have agreed to operate their systems as a reserve sharing group as defined by the WECC, and the NWPP reports to the WECC on compliance performance as a single control area. Each member of the Agreement is required to carry a minimum contingency reserve obligation (CRO) of 5 percent of its load responsibility served by hydro resources, plus 7 percent of its load responsibility served by thermal resources. Each member also reports its most severe single contingency (MSCC). The greatest individudal MSCC becomes the MSCC of the NWPP. If this is greater than the sum of each member's CRO, then each member's CRO will be increased proportionately until the reserve requirement for the NWPP MSSC is met.

The PNSC automatically (through telemetering) calculates each control area reserve obligation every four seconds and also calculates the control area available reserves. If a control area is not meeting its control area obligation, the PNSC notifies the Control Area that it needs to take action to bring its control area into compliance. But even though the PNSC will monitor each individual control area, the PNSC's overriding concern here is whether the WECC in sum is meeting its reserve requirements. The PNSC is not attempting to address cost and equity questions when one control area is not meeting its obligation while another has excess reserves.

Each control area is responsible for arranging for its own reserves with its own resources and contracts. If a control area does not have supplies of its own that are cost effective in meeting its reserve requirements, that control area has the ability to gain access to supplies from another control area through a bilateral contract. Henwood did not reflect these short term purchases in modeling for this report because Henwood does not have data sufficient to allow modeling of these transactions. If Henwood were to assume that these short term purchases always occur (absent Grid West), then most of the benefit of Grid West would be eliminated.

Modeling Operating Reserve Obligations

For the Base Case, Henwood modeled each of the following control areas as separately meeting its own operating reserve margin.

Table 3-2
Control Areas Independently Managing Reserve Obligations in the Base Case

Avista	PacifiCorp East
BC Hydro	PacifiCorp West
Bonneville	Portland General Electric
Idaho Power	Puget Sound Energy
Montana Power	Sierra Pacific (N. Nevada)

In calculating the operating reserve requirements of these individual control areas, there will be no calculation of the most severe single contingency since this is a shared obligation today.

There are other control area operators in the Northwest, namely Seattle City Light, Chelan PUD, Douglas PUD, Grant PUD, and Tacoma City Light. Henwood did not separately model these control areas, but rolled these control areas into the BPA control area for modeling purposes. This is a reasonable assumption since BPA and each of these control areas both together and separately have sufficient hydro capacity to cover their reserve obligations.

In modeling the Base Case control area reserve requirements, Henwood assumed that each of the control areas will be able to use their shares of mid-Columbia hydro rights to meet their reserve obligations.

In the Grid West Case, all these individual control areas (except for British Columbia, Nevada Power, and Utah) were rolled into a single control area for modeling purposes. As currently envisioned, the "end state" Grid West RTO for the Northwest does not require rolling all control areas into a single control area. That is a voluntary activity. However, for purposes of the modeling we will assume that all control areas voluntarily roll into a single control area in the Northwest.

In the Base Case Henwood did not calculate the most severe single contingency because of the existing sharing arrangement. It is expected that the most severe single contingency will not impact the results since the most severe single contingency criterion in the Base Case would also apply to the Grid West Case.

3.6 Coordination of Transmission & Generation Maintenance Events

To study the economic impact that RTO coordination of scheduled generation maintenance would have, Henwood performed a separate study, where MARKETSYM was run for 8,760 hours, simulating the year 2006 for the Base Case and the Grid West

Case. To perform this analysis, Henwood developed a Base Case maintenance schedule profile using actual Northwest generation data to ascertain how Northwest generators currently schedule maintenance. Based on this data, Henwood determined that today, scheduled maintenance of generation is predominantly carried out in the months of March, April and May. Armed with this information, Henwood assumed that, in the Base Case, scheduled maintenance would be performed predominantly in these months.

To simulate the Grid West Case, where generation maintenance would be managed at the RTO level, Henwood allowed MARKETSYM to optimize scheduled maintenance. The results from these two simulations showed that the RTO-wide optimized maintenance schedule did not improve on the efficiency of the Base Case maintenance schedule. Henwood concluded from this analysis that scheduled maintenance is already being performed with a level of efficiency such that RTO level coordination would not significantly improve upon it.

3.7 Coordination of Hydro Scheduling

Hydro scheduling is treated similarly in the Base Case and in the Grid West Case. It is expected that the rules and procedures from the dispatch of hydro generation in the Northwest are well established and that Grid West formation will have little impact on its use. The use of hydro generation to meet reserve margin requirements is addressed in other sections of this study.

3.8 Rated Transmission Capability (RTC) and Operational Transfer Capability (OTC)

The Total Transfer Capability (TTC) for an interface is the total amount of electric power that can be transferred over the interface in a reliable manner in a given time-frame. In the WECC, it is often desirable to pre-determine what TTC might be across specific paths. RTC and OTC are based on TTC ratings for specific paths. RTC is determined in accordance with specific procedures established by WECC. It is a number that rarely changes. OTC is a rating that is equal to or less than the RTC. OTC is generally established on shorter time frames (e.g., seasonal or daily) based on then known conditions.

Capacity Benefit Margin (CBM) is the amount of transmission transfer capability reserved by load serving entities to ensure access to generation to meet generation reliability requirements. CBM is the portion of TTC that cannot be used for reservation of firm transmission service because of uncertainties in generation system operation The Transmission Reliability Margin (TRM) is the portion of TTC that cannot be used for reservation of firm transmission service because of uncertainties in transmission system operation.

Existing Transmission Contracts (ETC) are contracts that are in existence with pre-authorized call on TTC.

OTC minus ETC minus CBM minus TRM determines the Available Transfer Capability (ATC) for an interface that is available for short term transmission reservations.

In the Base Case, Henwood has used a forecast of OTC on the transmission paths indicated in Appendix A. For example, on the West-of-Cascades-North path, the OTC is assumed to be 9,800 MW while the RTC is 10,200 MW. In other words, Henwood assumes that transmission operators have reduced the transfer capability by 400 MW to reflect some combination of CBM, TRM, other operating conditions, and uncertainties caused by lack of information on what is happening on the transmission grid owned by others. For the Grid West Case, Henwood has increased all OTCs by one percent (but not to exceed RTC) to reflect the fact that transmission operators now know what is happening on the transmission system of others and that flow based scheduling, rather than contract path based scheduling, may allow increased OTC. In this case, the reduction of 400 MW on the West-of-Cascades-North path would be adjusted to 302 MW. It is not expected that CBM, TRM and other operating conditions will be impacted by the formation of Grid West. Henwood believes that this assumption represents an improvement that would be difficult to achieve, and therefore is a conservative assumption for this study.

3.9 Seams Issues

For the Base Case and the Grid West Case, the topology outside of the Grid West geographical area will remain unchanged. Henwood assumed that interchange developed by schedulers among RTO areas (California ISO, WestConnect, and others outside Grid West) will not be affected by congestion management procedures invoked by each RTO area.

3.10 Contract Path Scheduling Limits

Contract path scheduling will be limited by the same physical transmission constraints in the Base Case and in the Grid West Case. Ratings from the WECC 2003 Path Rating Catalog were used to develop constraints among contractual paths within the Northwest. Appendix A illustrates path ratings used by Henwood for both the Base Case and Grid West Case.

4 SUMMARY OF MODELED RESULTS

In summary, Henwood's analysis indicates that the gross benefits of Grid West will likely be much lower than the gross benefits indicated by Tabors Caramanis. Henwood's results indicate that the gross benefits will likely be no higher than $78 million per year, and probably much less. In the analysis, Henwood sees the system operation today as being much more efficient than does Tabors Caramanis in the following three areas:

a) **Transmission rate pancaking**. The Tabors Caramanis modeling assumes that there are pancaked rates when moving all power from generation in the East to loads in the West. From an hourly dispatch point of view, this is simply not true. As Section 2.3 explained, most transmission service in the Northwest is based on fixed fee type contracts that do not influence hourly dispatch decisions. 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. This does not happen very often today. However, in a "with RTO" case this would not happen at all, so in that case there may be savings in improved dispatch with an RTO.

b) **More efficient meeting of reserve requirements**.
   a. Tabors did not make available to control areas the hydro spinning reserve capability to which those control areas have contract rights. Henwood's modeling reflects the fact that control areas do in fact use the reserve capabilities available in their long term contract rights.
   b. Tabors did not allow unused hydro to be fully counted toward reserve requirements. Henwood assumed that unused hydro can be fully used to meet reserve requirements if necessary. Henwood assumed further that the quantity of reserves that each control area needed to be held was determined through the Northwest reserve-sharing agreement and was limited to the 5%/7% criterion, not the maximum single contingency outage criterion.
   c. Tabors assumed that without the RTO, each control area would need to meet its own control area reserve requirements without being able to call upon economic, but unused, capabilities from other control areas. While Henwood believes that control areas do engage in short term bi-lateral contracts today to call upon economic, but unused, capabilities from other control areas, for this study Henwood assumed that this was not being done.[20] This biases the modeling results in favor of Grid West.

c) **Generation Maintenance Scheduling.** Tabors Caramanis assumed that without an RTO, each of the many control areas that exist in the Northwest today would perform some analysis of control area loads in isolation and then

[20] Henwood is aware that short term bi-lateral contracting is done from time to time when certain control areas are in need of economic sources of reserves. However, Henwood does not have information on the extent of this type of bi-lateral contracting that occurs today. Therefore Henwood conservatively assumed it was not happening at all for purposes of this study.

schedule generation maintenance around those load patterns, irrespective of power-market conditions. By doing this, the Tabors Caramanis process yielded thermal generation maintenance occurring in summer months when WECC power markets are expected to have the highest prices. Henwood's approach was to look at when thermal maintenance is actually being scheduled today and then allow the model to optimize the scheduling of thermal generation maintenance from a single control area standpoint. Henwood could not find a computer optimized schedule that provided better maintenance scheduling than those maintenance schedules occurring today. Therefore, Henwood incorporated historical maintenance scheduling patterns in both the Base Case and With Grid West case since the historical maintenance schedule appeared virtually identical to the optimal maintenance schedule.

In addition, Tabors erroneously counted the reduction in some costs assigned to load-based transmission rates as true gains in economic welfare rather than changes in transfer payments. Henwood corrected for this by simply calculating the change in Grid West generation cost between the Base Case and the Grid West Case. Henwood did need to adjust for increases in generation in Grid West in the Grid West Case. This adjustment involved applying an appropriate price to the increased export and then crediting the total to the change in total power costs, to derive an estimate of the change in power costs in the Northwest only. The Henwood approach eliminated the analysis of transfer payments and only counted benefits that represent true gains in economic welfare for the entire region. We estimate that Tabors erroneously counted $157 million in transfer payments (WECC-wide) as economic benefits in their analysis of RTO West. This estimate is the difference between the change in total benefits and the change in production costs.

Largely as a result of these major differences in assumptions, Henwood has calculated gross benefits of only $78 million per year from formation of an RTO in the Northwest.[21] This compares to Tabors Caramanis' calculated benefits of $410 million per year.

The following table identifies the benefits associated with each modeling assumption in Henwood's analysis:

[21] The $78 million is made up of $73 million caused by assumed efficiencies gained by sharing operating reserves. The $73 million operating reserve benefit assumes that control area operators are not performing short term bi-lateral contracting for ancillary services when needed to meet its control area reserves. Henwood knows that some such contracting is happening today, therefore this benefit is overstated. In the extreme, if control areas enter into short term contracts today every time they are in need, then this estimated $73 million benefit would be reduced to zero.

Table 4-1
Henwood Study Assumptions

	Henwood Study Assumptions		
Study Parameters	Status Quo	End State	Gross Benefit
Pancaked Wheeling Rates	For majority of transactions, no incremental transmission rate charges.	Any existing pancaking for wheeling rates eliminated.	$4 million
Operating Reserve Requirements	Each control area meets its own reserve requirements (as tempered by a reserve sharing agreement) without being able to call upon economic, but unused, capabilities from other control areas. Each control area can utilize its contract hydro supplies. Hydro spinning reserve capability may be fully utilized.	Most control areas are voluntarily combined such that all capabilities within the combined area are economically available.	$73 million
Gen & Tx Maintenance Coordination	Actual generation maintenance history used.	Actual generation maintenance history used (model revealed this was the optimized schedule).	$0 million
Transmission Capacity Allowed Utilization	Based on actual allowed utilization limits.	Increase allowed utilization, not to exceed WECC rated amounts.	$1 million
Coordination of Hydro Scheduling	Being done today	The same	$0 million
Seams Issues	Being done today	The same	$0 million
Contract Path Scheduling Limits	Assumed some inefficienty today	Assumed some increase in efficiency (See Transmission Capacity Allowed Utilization above)	Included in $1 million above

In addition, both Henwood and Tabors attempted to estimate the costs associated with ongoing RTO operations. Applying the 2004 weighted average carrying costs of the nation's existing RTOs to Grid West's projected annual demand produces an estimated annual revenue requirement for Grid West of $184 million per year in 2004. Adjusting this operating cost number for actual growth trends experienced by existing RTOs, Grid West's projected annual revenue requirement could increase to $221 million per year by 2006. For this study, Henwood has averaged this range of costs and conservatively assumed $200 million in annual operating costs for Grid West. Given that Tabors Caramanis did not have as complete a cost history at the time of their study, the Tabors operating cost estimate was based on a much lower weighted average carrying cost and only amounted to $135 million. Tabors also did not take into account the actual pattern of inflation in RTO costs, which this report has done in making an estimate of net costs and benefits for 2006.

In summary, where Tabors calculated net benefits of RTO formation, Henwood shows an annual net cost of approximately $122 million due to RTO formation [an average of $200 million in annual costs less $78 million in annual benefits]. Henwood believes that this $78 million in benefits is generous given the assumption we made that control areas are not making economic short term reserve-associated short term bi-lateral contracts today. Further, these figures are based on the assumption that the alternative to Grid West is the status quo. If alternative institutions and/or agreements are reached to overcome some of the regional problems, the incremental net benefits from forming Grid West will be reduced even further.

5 STARTUP AND OPERATING COSTS FOR RTOS

Prior studies on the benefits and costs of RTO formation in the Northwest have included estimates of the cost of forming and operating an RTO. Those prior studies generally looked at existing RTOs to estimate costs associated with an RTO in the Northwest. Significant new information is now available regarding the actual start-up and operating costs of existing RTOs. For this report, Henwood has relied on a recent analysis of these matters prepared by Margot Lutzenhiser, formerly of the Public Power Council. This analysis shows that existing RTOs display a substantial upward trend in costs, reflecting growth in organizational size and scope.

Recognizing that it is difficult to predict where Grid West would fall in the spectrum of these costs, the Lutzenhiser analysis applied Grid West annual demand data to a calculated, weighted-average cost ($/MWh) from existing RTO start-up cost information, and estimated Grid West start-up costs at $177 million. To estimate an annual operating revenue requirement for Grid West, a 2004 weighted-average of existing RTO operating cost information was calculated and applied to Grid West annual demand data, resulting in an estimated annual operating cost of $184 million for Grid West in 2004. Adjusting the operating cost estimate for actual growth trends in these costs, the Grid West estimate for annual operating costs would increase to $221 million per year by 2006. A summary of this work is presented in Section 5.1 below.

5.1 Review of RTO cost data

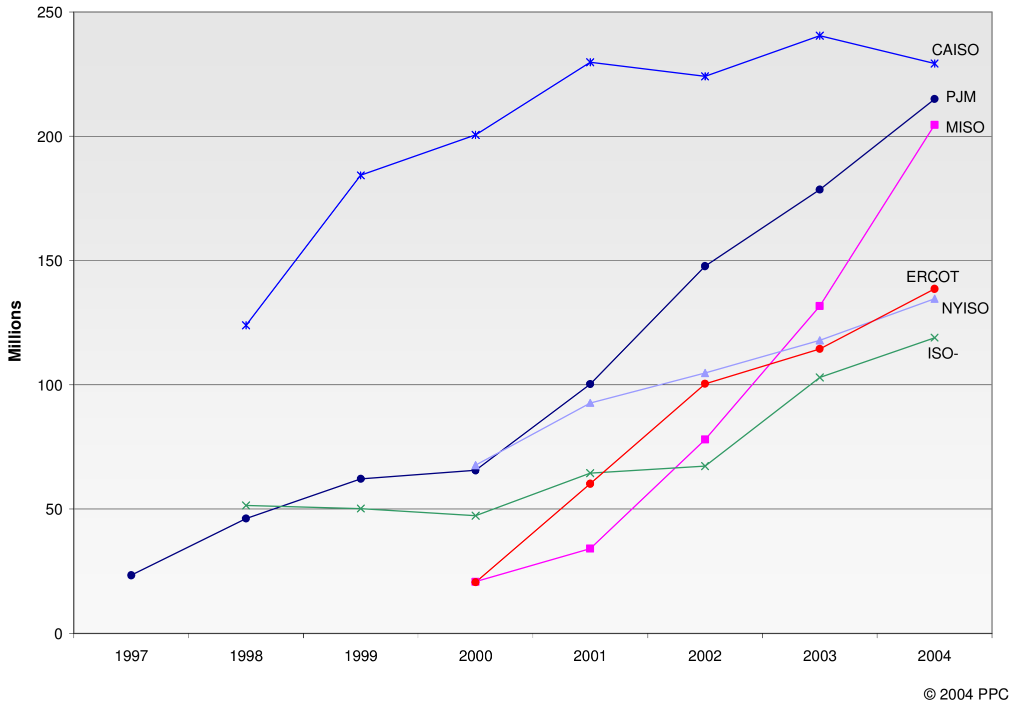
In 2004, about $1.04 billion will likely be spent funding the operation of six RTOs – California ISO, NYISO, PJM, MISO, ISO-NE and ERCOT.[22] Since 2000, total U.S. RTO operating expenses have increased by 143 percent, and are growing at an annualized rate of 20 percent per year.

Although some have grown faster than others, individually *every single* RTO displays a substantial upward trend in costs. Figure 5-1 depicts the operating cost history of the nation's RTOs. MISO has experienced the most rapid growth, with a 500 percent increase over the past four years (from $34 million in 2001 to a budgeted $210 million in 2004). PJM has experienced a similar increase, but over a much longer period of time. PJM had $21.4 million in operating expenses in 1997, and will likely spend a budgeted $215 million in 2004. Others, such as ISO New England, experienced a slower expansion, increasing expenses from $57.5 million in 1998 to a budgeted $122 million in 2004.

[22] The term Regional Transmission Operator is used loosely to encompass existing ISOs and RTOs.

Figure 5-1
U.S. ISO/RTO Operating Costs Graph

U.S. ISO/RTO Operating Costs Including Amortization, Depriciation and Interest Expenses (2003 dollars)



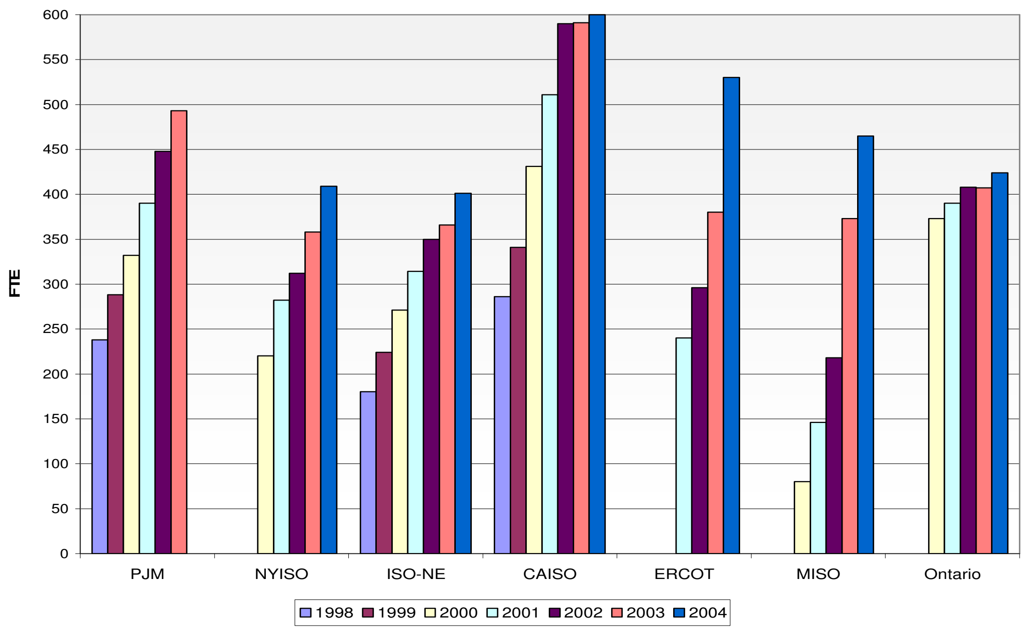
This upward trend reflects growth in organizational size and scope, as well as geographical breadth of operations. Over time, the RTOs have taken on new tasks, undergone market redesigns and have made upgrades in areas such as computer software. For instance, ERCOT built a new administrative building and a new control center in 2000, began operating a single control area for Texas in 2001, completed implementation of a retail choice program in 2002, and undertook a major wholesale market redesign effort in 2003. Similarly, PJM has systematically added markets, beginning with a bid-based wholesale energy market in 1997, locational marginal pricing congestion management system in 1998, real-time energy and capacity markets in 1999, and a spinning reserves market in 2002. The ISO-NE launched a wholesale energy market in 1999, made several market enhancements including some computer upgrades in 2000, launched a demand response program and created five new departments in 2002, and rolled out a major market redesign (SMD) in 2003. By contrast, development of the California ISO is often described as a "big bang" where the majority of functions were built into the initial market design (and a large investment was made up front).

In addition to internally directed organizational growth (i.e., adding markets and improving services), RTOs also respond to FERC initiatives. Most RTOs have made substantial efforts to conform to FERC's proposed SMD. NYISO and New England are in the process of implementing Standard Market Design (SMD), MISO has integrated

SMD into its market design (launch date March 2005), PJM is working with MISO to develop a common market design, and the California ISO is currently performing market simulations to test its standard market redesign.

One way to measure institutional growth is through staffing levels. Staffing levels shown below in Figure 5-2 reflect the core institutional staff because there is no consistent reporting of contract employees. Many RTOs have relied substantially on contractors, especially during start-up and market redesigns. California employed 412 contractors in 1999 and 348 in 2000.[23] MISO currently employees 110 contractors for its market implementation plan (which may be contained in its FTE count for 2004).

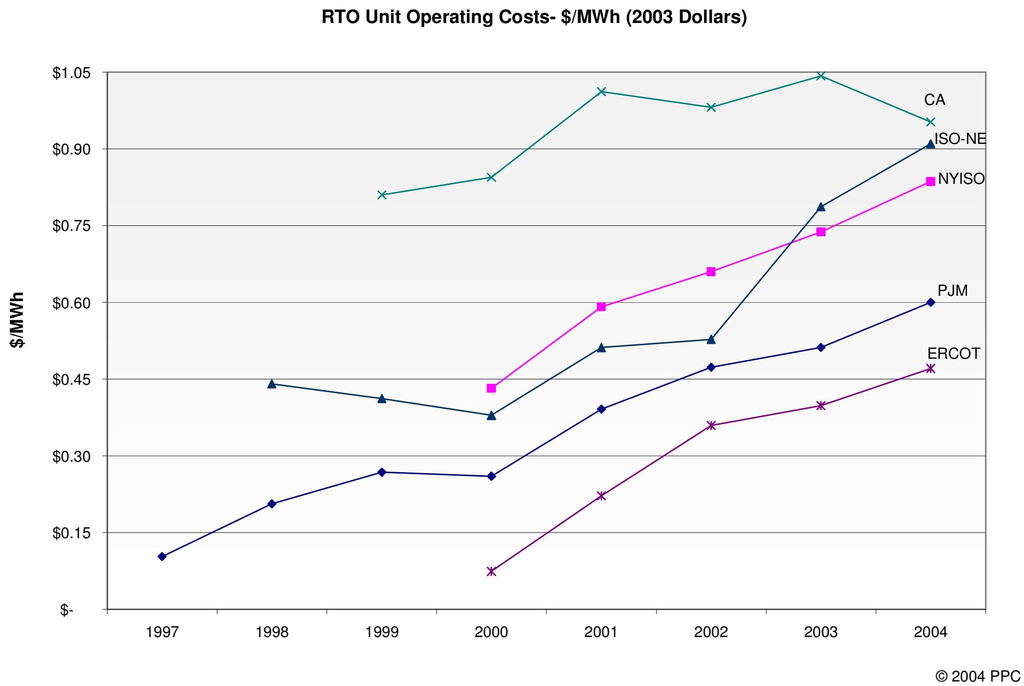
Figure 5-2
ISO/RTO Staffing Levels



To make an objective comparison of costs across the RTOs, consider the load each RTO serves as measured by annual energy demand. Figure 5-3 depicts the unit operating costs of several RTOs. PJM serves the largest electrical load, followed by ERCOT, California ISO, NYISO and finally ISO-NE. With the exception of PJM, the annual demand of each RTO has remained fairly constant. Consequently, PJM is the only RTO whose budget has been driven by market growth (i.e., geographical expansion). For RTOs with relatively constant annual demand levels, their unit operating costs ($/MWh) exhibits a growth pattern nearly identical to that of their gross operating costs.

[23] California ISO "Proposed FY 2000 Grid Management Charge" Appendix A, 11/12/1999,at 13.

Figure 5-3
RTO Unit Operating Costs



Although ISO New England has the lowest annual expenditure of any U.S. RTO, its unit cost is second only to the California ISO's. Conversely, although PJM has one of the highest operating costs, its membership has expanded and thus its unit cost has remained among the lowest. The weighed average unit operating costs for 2004 is $0.73 per/MWh (2003 dollars). MISO is excluded from this calculation because no reliable annual energy data are available (once the wholesale market design is in place, MISO will calculate annual energy). Table 5-1 shows the data on which figures 5-1, 5-2, and 5-3 are based.

Table 5-1
RTO Operating and Implementation Costs (2003 Dollars)

	Year	Annual Operating Expenses	Depreciation, Amortization and Interest Expense	Assumed Revenue Requirement	Net Annual Energy (TWh)	Unit Operating Cost ($/MWh)	FTE	Start Up Costs:[24]
PJM[25]	1997	$25.1	$0.10	$25.2	244.23	$ 0.10		$140
	1998	$50.8	$0.47	$51.3	248.53	$ 0.21	238	
	1999	$66.8	$1.60	$68.4	255.46	$ 0.27	288	
	2000	$64.0	$4.16	$68.2	262.08	$ 0.26	332	
	2001	$62.4	$40.78	$103.2	263.81	$ 0.39	390	
	2002	$117.9	$37.75	$155.6	329.00	$ 0.47	448	
	2003	$125.4	$53.05	$178.5	348.70	$ 0.51	493	
	2004	$170.2	$39.26	$209.5	349.00	$ 0.60		
NYISO	2000	$59.9	$7.77	$67.7	156.63	$ 0.43	220	$82
	2001	$83.3	$9.39	$92.7	156.70	$ 0.59	282	
	2002	$93.8	$10.95	$104.7	158.74	$ 0.66	312	
	2003	$98.9	$18.89	$117.8	159.73	$ 0.74	358	
	2004	$104.5	$30.01	$134.5	160.99	$ 0.84	409	
ISO-NE	1998	$30.7	$20.80	$51.5	116.89	$ 0.44	180	$55
	1999	$37.7	$12.45	$50.2	121.87	$ 0.41	224	
	2000	$45.8	$1.48	$47.3	124.89	$ 0.38	271	
	2001	$59.4	$5.05	$64.5	125.98	$ 0.51	314	
	2002	$62.7	$4.60	$67.3	127.46	$ 0.53	350	
	2003	$68.0	$34.97	$102.9	130.78	$ 0.79	366	
	2004	$72.0	$46.94	$119.0	130.75	$ 0.91	401	
CAISO	1998	$88.1	$35.89	$124.0	169.24	$ 0.73	286	$301
	1999	$129.3	$54.98	$184.2	227.53	$ 0.81	341	
	2000	$139.8	$60.70	$200.5	237.54	$ 0.84	431	
	2001	$161.3	$68.44	$229.7	227.02	$ 1.01	511	
	2002	$160.5	$63.63	$224.1	228.34	$ 0.98	590	
	2003	$176.6	$32.79	$240.4	230.65	$ 1.04	591	
	2004	$179.0	$42.57	$229.2	240.72	$ 0.95	600	
ERCOT	2000	$19.2	$1.34	$20.5	277.18	$ 0.07		$137
	2001	$44.2	$15.97	$60.1	270.56	$ 0.22	240	
	2002	$60.8	$39.65	$100.4	279.60	$ 0.36	296	
	2003	$69.1	$45.31	$114.4	287.35	$ 0.40	380	
	2004	$88.2	$50.38	$138.6	294.40	$ 0.47	530	

[24] Start-up costs have not been inflation adjusted
[25] PJM's costs exclude interconnection study fees that are directly passed through to utilities and independent power producers.

	Year	Annual Operating Expenses	Depreciation, Amortization and Interest Expense	Assumed Revenue Requirement	Net Annual Energy (TWh)	Unit Operating Cost ($/MWh)	FTE	Start Up Costs:[24]
MISO	2000	$11.9	$8.87	$20.7			80	$145
	2001	$20.3	$13.79	$34.1			146	
	2002	$42.5	$35.49	$78.0			218	
	2003	$88.2	$43.40	$131.6			373	
	2004	$142.6	$61.96	$204.6			465	
		2001 Weighted Average				$ 0.53		$157
		2002 Weighted Average				$ 0.58		
		2003 Weighted Average				$ 0.65		
		2004 Weighted Average				$ 0.73		

5.2 Estimate of Start-up and Operating Expenses for Grid West

For the purpose of this study, the annual energy in the Grid West territory is estimated at 252 TWh (consisting of Avista, BPA, BC Hydro, Idaho Power, NorthWestern Energy, PacifiCorp, PGE, PSE, and Sierra Pacific). Applying the weighted average $/MWh start-up cost of the nation's existing RTOs to Grid West's annual demand results in an estimate of $177 million in start-up costs for Grid West.[26] Applying the existing RTO's 2004 weighted average $/MWh operating cost to Grid West's annual demand produces an estimated revenue requirement of $184 million.[27] If the average RTO operating cost continues to rise at the current level for the next two years, and then levels off with no further increases, the Grid West estimate would increase to $221 million by 2006. For this study, we have conservatively averaged the estimated 2004 and 2006 operating costs to produce an estimated operating cost of $200 million.

Although the data show a clear pattern of growth, it is difficult to project future costs. RTO expenses are subject to a high degree of variability and uncertainty[28]. So far, only the California ISO shows signs of leveling costs. Recent financial planning documents confirm the California ISO's commitment to minimizing future increases.[29] Similarly, the NYISO strategic plan (2005-2008) shows only incidental increases (1.7 percent-2.6 percent) over the next five years.[30] This should be balanced with the fact that NYISO is in the process of implementing a new market design which generally drives costs up.

[26] Weighted average start-up: $0.80 MWh.
[27] The weighed average $/MWh operating costs for 2004 is $.73 per/MWh (2003 dollars). The Tabors Caramanis RTO West study estimated costs of $127-$143 million (calculated with an average carrying cost of $0.45-$0.51MWh and an annual load of 280 TWh).
[28] In a September 17th article published in the APPA Public Power Daily titled "Regulators seek to get a handle on RTO costs, accounting", FERC Commissioner Nora Brownell states that FERC audits found inconsistency with accounting rules followed by investor-owned utilities, making it difficult, if not impossible, to review RTO costs.
[29] California ISO "2005 Budget Development Stakeholder Workshop" Presentation, July 7, 2004.
[30] "New York Independent System Operator Strategic Plan 2004 – 2008" 1/21/2004, at 35.

MISO's market implementation budget continues to expand. This summer, MISO's board of directors informed stakeholders of plans to request authorization for an additional $55.6 million in market implementation costs (bringing the total to $247.8 million). Experience from the other RTOs suggests that MISO's budget will likely continue to escalate until its market plan has been fully implemented and the kinks eliminated. This should be tempered with the fact that MISO covers a large service territory with annual energy estimates ranging from 680 to 784 TWhs (which translates into operating costs of $0.27- $0.31/MWh for 2004). If MISO's annual energy is within these estimates, its operating budget could more than double before MISO would approach the average $/MWh operating cost of the remaining RTOs.

ERCOT's revenue requirement is expected to increase from $138 million in 2004 to $218 million in 2006, topping off at $228 million in 2007.[31] ERCOT is a unique entity that both is the sole control area operator for Texas and runs a large retail choice program. ERCOT is in the process of developing and evaluating a new market platform called Texas Nodal Pricing. In Texas PUC rate case testimony, ERCOT's financial officers describe the development and implementation of Texas Nodal Pricing as a major cost driver.

As further evidence that RTO costs are growing to levels that are of concern to many industry participants, on September 16, 2004 FERC issued a Notice of Inquiry on the subject (Docket No. RM04-12-000). In the inquiry FERC has asked the following questions:

> *Do not-for-profit RTOs/ISOs have the appropriate incentives to contain costs? If not, what are the right incentives (and why would they be the right incentives) and how should they be implemented?*

The FERC inquiry discusses in some detail the appearance that RTOs are not containing costs.

5.3 Conclusion

History has shown that, no matter how limited in scope and budget the initial design of an RTO may be, the trend is for costs to escalate well beyond initial estimates. The costs of forming and operating an RTO are much higher than earlier estimated and they are still growing. In addition, regardless of the size and scope of an RTO, each of these institutions has grown in excess of 400 FTEs. Although it is impossible to exactly determine the cost future for the proposed Grid West, it would be imprudent to ignore the relevance of these facts when estimating operating costs for Grid West. For this report, we have assumed that Grid West costs of implementation and operation will be similar to that of existing RTOs/ISOs. The operating costs alone are estimated to be $200 million per year.

[31] ERCOT 2004 Texas PUC rate filing, Docket #28832.

6 OTHER IMPACTS/UNINTENDED CONSEQUENCES

One can speculate on a number of other possible benefits and costs of RTO formation. While some have argued that there would be fewer large power outages under an RTO (for example, the October 2000, RTO West Potential Benefits and Costs Study assumed that RTO West would result in fewer outages and calculated that significant savings could result), others can point to examples where the existence of an RTO seems to have contributed to, or at least done little to mitigate, failures of the power and transmission system. For example, the catastrophic outage experienced by the Midwest and Northeast last year occurred in an established RTO environment. The Midwest ISO was charged with monitoring the system to ensure such outages did not happen. It has been stated that this outage was an unlikely combination of a number of events and that it would be highly unlikely for such a combination to occur again. Nevertheless, it is instructive to note that the events and outage occurred under an environment where MISO and other ISOs/RTOs had been formed to help protect against such outcome.[32]

Another example of a large outage that occurred in an RTO environment is the outage that occurred on March 8, 2004 under the aegis of the California ISO. On that date the California ISO gave instructions for Southern California Edison to shed load for 20 minutes, from 6:30 PM to 6:50 PM. The power outage affected about 70,000 SCE customers. After a fact finding investigation, the California ISO determined that this curtailment was caused by errors made by its operators.[33]

During the 2000-2001 power crisis in the WECC we learned that the CAISO tariff and protocols were susceptible to gaming. This unintended consequence occurred as a result of the formation of the CAISO and resulted in adverse cost impacts to customers in WECC.

As a theoretical matter, it is entirely reasonable to speculate that reliability could be reduced by formation of an RTO. Today, without the RTO, there are numerous control areas in the northwest in addition to the Pacific Northwest Security Coordinator. Each of these entities has a fully staffed 24 hour operation. These operations are watching the system to see if problems are occurring with the goal of having human intervention if something goes wrong. What is happening in one person’s control area is often “seen” by another control area because of the nature of an interconnected grid, and the operations of all control areas are “seen” by the PNSC. For example, a frequency

[32] The Final Report prepared by the U.S.-Canada Power System Outage Task Force on the "August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" indicated that there were four groups of causes for the blackout. Group 4 of the causes was a "Failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support." The report indicated a number of violations identified by NERC. For example, one of the MISO violations found was "MISO did not notify other reliability coordinators of potential system problems as required by NERC Policy 9, Section C, Requirement 2."

[33] See CAISO press release dated March 15, 2004.

oscillation will likely be seen by the PNSC and all control areas even though the causing event may be a single location. With this multiple control area operation, if a problem occurs in one control area that is not immediately detected by that control area operator, another control area operator will likely see the problem has occurred and will "sound the alarm." If, as a result of RTO formation, this monitoring function is reduced to one single control area, then if that control area operator fails to react to a problem, the back up alarm system has been eliminated.

It is also entirely possible that an RTO would increase costs due to its not-for-profit status. If there is inadequate incentive to control costs and with the full responsibility for ensuring reliability, the RTO would have a natural tendency to incur more costs in order to increase reliability. While very high reliability is desirable, at some point the additional costs incurred may not justify the incremental increase in reliability. It will likely be very difficult to monitor all RTO actions to ensure this tradeoff between cost and reliability is being appropriately balanced.

Concerns have also been raised that taxes on BPA-owned transmission facilities may increase significantly as a result of RTO formation because some degree of control will be transferred from a federal entity exempt from state taxes to an entity that may be taxed. Indeed, the State of Oregon has already successfully collected taxes from several Northwest utilities that own transmission rights on the Third AC Intertie in somewhat similar circumstances. See *Power Resources Cooperative v. Department of Revenue,* 330 OR 24 (2000), *aff'g* 14 Or Tax 479 (1998). A preliminary review of the potential tax liabilities arising from formation of RTO West, conducted by Lane Powell Spears Lubersky in April 2002, estimated that new taxes could be in the range of $100-$200 million annually, with a potential one-time tax payment in the range of $248-328 million, could result from formation of RTO West. This potential consequence needs to be examined in more detail, as the repercussions could clearly be devastating to Northwest utilities.

Numerous examples can be drawn upon to make statements about whether RTOs actually increase or decrease outages and/or costs (and subsequently increase or decrease costs to ratepayers). What is important is to bear the risk of unintended consequences in mind when weighing the benefits and costs of a proposed RTO.

7 MARKET CONCENTRATION

A study of market power is not within the scope of this engagement. However, Henwood has reviewed the Market Concentration Analysis done by Tabors Caramanis in their March 11, 2002 RTO West report. Henwood is also aware of studies done for other Northwest utilities for use in filings at FERC. These studies indicate that BPA and B.C. Hydro have dominant positions in market areas in the Northwest in general and on both sides of many constraints, which makes it difficult, if not impossible, to obtain market-clearing prices that are unaffected by these seller's size. A thorough market power analysis is warranted prior to enabling the formation of an RTO in the Northwest.

In addition, BPA has market power in several sub-areas of the U.S. Northwest because BPA has several large hydro generation units located across the system that have significant flexibility in their ability to generate from one hour to the next.[34] BPA also has a significant amount of flexibility in choosing where it generates. Given BPA's significant flexibility in changing hourly generation levels at its many hydro plants that are distributed across the Northwest, BPA can create (and relieve) congestion on a path simply by how it chooses to dispatch its hydro on an hour. BPA thus has considerable sub-regional market power as a result of (a) its relatively large amount of capacity, (b) the broad geographic spread of its dams, and (c) the significant amount of flexibility it has in hourly use of its generation.

This matter would need to receive considerable attention prior to a decision to form an RTO that encourages market based pricing. Further, this matter would be a significant problem in any plan to move to Locational Marginal Pricing to deal with congestion.

[34] Fish and other non-power constraints can restrict the amount of hydro generation that can be moved from one month to the next, but in general BPA has significant ability to adjust its hourly generation levels at a plant.

8 COMPARISON OF HENWOOD AND TABORS CARAMANIS RESULTS

As indicated earlier in this report, one of the tasks that Henwood was charged with was to compare the results of the Tabors Caramanis study with its own results. The Henwood study was performed in a manner similar to the Tabors Caramanis study, focusing on the net benefits of moving from today's environment to an end state where a regional transmission organization is in place and operating.

For example, a potential benefit of RTO formation is to eliminate any pancaking of transmission rates, where pancaking results in uneconomic dispatch of power supplies. Further, a potential benefit of RTO formation is to make sure that reserve obligations are covered in a region-wide optimal manner rather than through a control area by control area manner, in which unused capabilities in one control area may be left unused while another control area resorts to expensive approaches to meeting reserves.

Most analysis of the benefits and costs of RTOs will examine what benefits can be achieved by removing inefficiencies such as these that might exist today. Henwood and Tabors Caramanis have both attempted to quantify improvements that might occur from these and similar activities.

As already discussed elsewhere in this report, Henwood sees the system operation today as being much more efficient than Tabors Caramanis does in the areas of pancaking, operating reserve requirements, and generation maintenance. The following table highlights some of the different assumptions used by Henwood and Tabors:

Table 8-1
Comparison of Henwood and Tabors Study Assumptions

	Henwood Study Assumptions		Tabors Study Assumptions	
Study Parameters	Status Quo	End State	Status Quo	End State
Pancaked Wheeling Rates	For majority of transactions, no incremental transmission rate charges.	Any existing pancaking for wheeling rates eliminated.	Pancaked rates apply when moving power from generation in the East to loads in the West.	Any existing pancaking for wheeling rates eliminated.
Operating Reserve Requirements	Each control area meets its own reserve requirements (as tempered by a reserve sharing agreement) without being	Most control areas are voluntarily combined such that all capabilities within the combined area are	Each control area meets its own reserve requirements without being able to call upon economic, but unused,	Most control areas are voluntarily combined such that all capabilities within the combined area are

	able to call upon economic, but unused, capabilities from other control areas. Each control area can utilize its contract hydro supplies. Hydro spinning reserve capability may be fully utilized.	economically available.	capabilities from other control areas. Control areas are not able to use their contract hydro supplies. Hydro spinning reserve capability is limited.	economically available.
Gen & Tx Maintenance Coordination	Actual generation maintenance history used.	Actual generation maintenance history used (model revealed this was the optimized schedule).	Generation maintenance schedule around individual control area load patterns.	Modeled optimization of maintenance based on the combined area.
Transmission Capacity Allowed Utilization	Based on actual allowed utilization limits.	Increase allowed utilization, not to exceed WECC rated amounts.	Based on actual allowed utilization limits.	Based on actual allowed utilization limit.

The benefit of each of these modeling assumptions is identified in the following table:

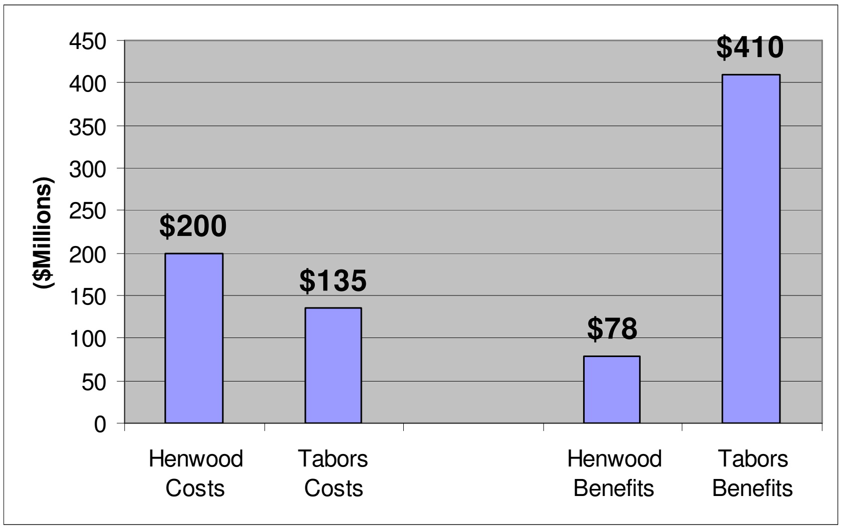
Table 8-2
Tabors/Henwood Benefits Comparison Summary

	Tabors	Henwood
	($million)	($million)
Pancaked Wheeling Rates	233	4
Operating Reserve Requirements	150	73
Gen & Tx Maintenance Coord.	27	0
Transmission Capacity Utilization	0	1
Total Benefit from RTO	410	78

Finally, as noted in Section 5, Tabors calculated carrying costs associated with RTO West of only $127 million, whereas Henwood believes, based on information gathered by Margot Lutzenhiser, that the operating costs of Grid West would be closer to $200 million. Henwood believes that Tabors underestimated the costs associated with a Northwest RTO because they did not have as complete a cost history at the time of their study.

In summary, where Tabors calculated net benefits of RTO formation, Henwood shows an annual net cost of approximately $122 million through RTO formation [an average of $200 million in annual costs less $78 million in annual benefits]. Henwood believes that the $78 million in benefits is generous given the assumption we made that control areas are not making economic short term reserve-associated transactions today. Further, these figures are based on the assumption that the alternative to Grid West is the status quo. If alternative institutions and/or agreements are reached to overcome some of the regional problems, the gross benefits resulting from forming Grid West will be reduced even further. Figure 8-1 compares the benefits and costs of Grid West as calculated by both Tabors and Henwood.

Figure 8- 1
Comparison of Henwood and Tabors Costs & Benefits



9 NORTHWEST TRANSMISSION PROBLEMS TODAY

Parties in the Northwest have identified a number of transmission problems that exist today, some more problematic than others. The list below is Henwood's description of those problems that have been raised by Henwood and a number of other stakeholders[35]. The combination of these groups includes most, if not all, of the Northwest stakeholders.

This chapter briefly discusses these previously identified problems. Chapter 10 will then discuss whether an RTO will likely be able to materially address these problems, as well as how these problems might be addressed without an RTO.

9.1 Oversold But Under-Utilized Transmission Grid

The statement that the Northwest transmission grid is oversold but underutilized refers to the concern by some parties in the region that the existing bilateral market may not be efficient enough to facilitate the optimal use of the existing transmission system through a robust secondary market. More simply said, during past efforts to add up the total amount of contracted-for transmission, some of the estimates have indicated that contractual commitments exceed the physical capacity of the system. However, observation of the transmission system's actual usage patterns and line loadings indicate that much of this capacity may be idle and or unused. Regional parties seeking access to the transmission system have theorized that this contrast may be due to existing methods for specifying and using transmission contract rights. Section 9.2 further explores the contracting aspect of this issue.

9.2 Transmission Rights

While in general many of the region's transmission rights are clearly defined in long-term contracts, many regional stakeholders believe that there is not enough clarity or transparency in how BPA manages portions of these transmission rights.

For example, in many contracts, transmission rights are not specified at pre-schedule in a manner that determines which specific resources are being delivered across which internal paths. Transmission rights are generally converted from node-to-node to system-to-system for scheduling purposes (e.g., Federal power (non-project specific) delivered

[35]Various parties have identified what they believe are transmission problems in the Northwest. For example, the RRG Platform group identified a long list of regional transmission problems. Similarly, the Transmission Issues Group (made up of several utilities and agencies in the region) has identified a shorter list of problems. Henwood provided its view of transmission problems in the Northwest at the SMD Policy Perspective Forum sponsored by the Northwest Public Power Association in December of 2002. Consensus does not exist among regional stakeholders regarding these transmission issues/problems or their relative seriousness.

over Federal transmission (internal paths or unrated paths) to a customer's service territory or control area).

PTP contracts have clearly identified POIs/PORs and PODs, and entities with these rights can often resell the unused capacity. However, due to the seasonal nature of transmission contract holder's native load (e.g., winter peaking demand), the unused firm capacity is generally available during the transmission contract holder's non-peak native load periods. The firm capacity is then typically re-marketed based on the load and power marketing demands of other parties and is dependant upon the availability of short term ATC on the Federal transmission system. Such transactions generally have a relatively short duration (e.g., 6 months or less). As a result, some parties feel that the remarketing of firm capacity of a longer duration is limited because the systems, including ATC calculations, do not support the full development of such markets.

NT contracts include rights to have power delivered to load as that load varies in real time. In the Northwest, the deliveries of power under these contracts are generally greatest in winter peak periods. As such, there is generally no need to reserve transmission capacity for these rights in non-peak hours and months. The unused transmission capacity that exists in non-peak hours reverts to the BPA Transmission Business Line (TBL), to be made available to others as determined by the TBL. The TBL may make this transmission capacity available in day ahead, hour ahead or real time markets as short-term firm and non-firm transmission capacity. Although it appears that such unused rights may be available in many non-peak hours and months for years into the future, the way in which TBL approaches this capacity is not transparent. It appears that new products may permit better utilization of the system.

Some regional parties feel that without more specificity in defining the use of internal paths, transmission capacity is not being fully utilized in either the long term or short term. An effort by the region to develop a "catalog" or inventory of transmission rights on a more detailed level was begun in 2003 for the purpose of converting such rights to Firm Transmission Rights (FTRs). This effort was abandoned before completion because of controversy over whether FTRs and Locational Marginal Pricing can or should be implemented in the Northwest, and because BPA and its customers could not agree on the scope of the rights to be inventoried.

9.3 Certain New Generation Is Not Getting Built

Some renewable projects may not be getting built in the Northwest because of the apparent lack of long-term firm transmission rights (as opposed to legitimate siting issues or a true lack of firm transmission). Long-term firm transmission may appear to be lacking due to the issues identified in Sections 9.1 and 9.2. When long-term firm transmission is denied to developers of new generation, two options generally exist: the developer can rely on short-term and non-firm transmission capacity, or agree to build new transmission lines. The first option is problematic from the viewpoint of potential customers and financiers, who are both likely to desire firm long-term transmission service for the new resource. The second option creates difficulties for the developer in terms of securing significant additional funds in advance of project construction, as well as dealing with the long lead times needed to build new transmission. From the developer's perspective, these limited courses of action can result in a project going undeveloped. From the region's perspective, if cost competitive or environmentally preferred generation is going undeveloped, the region may be paying more for power than necessary or causing unneeded environmental harm.

9.4 Transmission Rate Pancaking

Transmission rate pancaking refers to the payment of multiple embedded-cost transmission rates when wheeling power over multiple transmission owners' lines. Pancaking can occur in both short-term and long-term markets. As discussed earlier in this report, short-term pancaking is currently not a major problem in the Northwest because of the predominance of long-term transmission contracts with fixed monthly transmission payments. However, long-term firm transmission contracts can themselves be pancaked, causing both greater hassle and higher costs to one party or another. As Chapter 10 will explain, though, this is a cost allocation issue. In other words, resolution of this issue is not likely to reduce overall costs on the system -- it will likely only affect how much of the costs each party will pay.

9.5 No Single OASIS

In order for there to be efficient use of the transmission grid, potential users of the grid believe they need to have easily accessible and accurate information regarding available transmission capacity. FERC has indicated that such information needs to be made available by transmission owners via an Open Access Same Time Information System (OASIS) web site. In the past there has been no common OASIS web site in the Northwest. Instead, each transmission owner has maintained its own site. Some parties believe that the process of accessing multiple OASIS web-sites to complete a single transaction interferes with the optimal use of the existing transmission system.

9.6 No Single Point Of Information On Available Transmission Capacity (ATC)

Longer-term transmission needs (e.g., 20 years) are made via special requests to individual transmission owners. Again, some parties believe that the lack of a single point of information for long-term available transmission capacity is causing a less than optimal operation of the power grid.

9.7 Contract Path ATC Versus Flow-Based Capacity

Today, power is scheduled over contract paths. In addition, long-term transmission contracts are often based on a contract path approach. Schedulers and long-term transmission purchasers look for the cheapest path that is available. These contract approaches do not reflect the fact that power will actually distribute across the transmission network based on the laws of physics. Some parties believe that the contract path approach is detrimental to the efficient operation of the system. Such an inefficiency could arise if transmission owners become excessively conservative in their calculations of Available Transmission Capacity (ATC) (because their ATC calculations rely on pre-existing contract path commitments but flows will be distributed by physical laws).

9.8 Lack Of Northwest Regional Transmission Planning Authority

The NWPP is home to the Northwest Transmission Planning Committee (TPC). The purpose of the TPC is to provide a forum for coordination of engineering issues related to reliable planning of the Northwest transmission system. However, participation in and adherence to the advice of the TPC is voluntary, meaning that no single entity has the authority to conclude, from a regional perspective, that certain transmission facilities need to be built, and then to ensure they are permitted, financed and constructed. Some parties believe that as a result necessary transmission upgrades have been identified but not built.

9.9 Ensuring Resource Adequacy And System Reliability

No single party is currently responsible for ensuring, for the entire Northwest region, that sufficient generation will be built to produce a reliable power system. Under current policies in the United States, each state is responsible for ensuring that adequate resources are developed for its residents. The Northwest Power and Conservation Council (NPCC) has the role of preparing a region wide power plan, but there is no requirement that such plan be adopted by utilities. Some of the Public Utility Commissions are dealing with this issue in Integrated Resource Planning forums, and some public agencies are performing similar types of analysis. However, on a regional level, a single entity does not exist to perform this function. Some parties feel that this results in less than optimal planning and resource development.

9.10 Need For Enhanced Reliability And Security

The Pacific Northwest Security Coordinator (PNSC) has been established to help ensure the reliability of the Northwest transmission system, including ensuring that operating reserves are being met. However, some parties believe that reliability and security of the transmission grid in the Northwest needs to be enhanced. These concerns seem to be focusing on the need for a single transmission operator to oversee the operation of the grid (rather than several different operators).

9.11 Lack Of Market Monitoring

Some parties feel that a market monitor is necessary in order to ensure that participants are not able to unduly influence prices.

9.12 Multiple Transmission Queues For Long-Term Service And Interconnection Of New Generation

As mentioned in Section 9.6, parties who need to use the transmission systems of more than one transmission owner must deal with each owner separately. Some parties believe that the multiple queues for long-term transmission service and interconnection lead to long lead times and create the need for expensive and sometimes controversial system impact studies. These parties believe that both of these factors serve to increase the level of difficulty and costs to some market participants to obtain long term transmission service.

9.13 No Day-Ahead Information For Dealing With Congestion

A regional uniform formal process that looks at day-ahead load forecasts and associated planned generation schedules to determine if the implementation of such schedules will likely create overloads on the system does not exist currently. As a result, some parties believe that an optimal resolution of a line overload by system operators may not be implemented.

9.14 Control Area Inefficiencies

Each control area operator is obligated to provide its own operating reserves. If one control area operator is faced with the possible need of running a thermal resource at partial load in order to meet its reserve requirements, while another control area operator has unused hydro capacity that could have been used, there may be inefficiencies. In today's world, control areas that are having difficulty may contact another control area (long term, day ahead, hour ahead, or real time) and arrange for unused resources. However, that is not done automatically or systematically region-wide. However, the Northwest does have an operating reserve sharing agreement, according to which 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.

10 POTENTIAL ALTERNATIVES FOR SOLVING TODAY'S TRANSMISSION PROBLEMS WITHOUT AN RTO

In this chapter, Henwood takes a look at the problems discussed in Chapter 9 and examines how serious each of these problems may be. If warranted, Henwood further discusses whether an RTO would be able to materially address these problems. In addition, Henwood reviews how these problems might be addressed without the creation of an RTO.

It is Henwood's opinion that many of the problems that regional stakeholders believe the Northwest is experiencing today are not likely to be solved by Grid West. In addition, other problems that Grid West is intending to solve can alternatively be solved without the formation of an RTO. The region needs to weigh the substantial costs of forming an RTO with the fact that other more cost-effective solutions already exist or could be put in place.

10.1 Oversold But Under-Utilized Transmission Grid

Henwood believes that the under-utilization of the Northwest transmission grid is a serious problem that leads to unnecessary infrastructure costs and higher transmission rates. Better utilization can be achieved by developing a different approach to (a) determining ATC and (b) scheduling transmission rights, which could enable a more efficient and optimal use of the existing transmission system, in part through identifying unused or unneeded rights that could be sold or resold. This is discussed in more detail in 10.2 below. Henwood believes that this can be completed without the development of an RTO, because a common approach to calculating ATC based on power flows across all systems is definitely possible. Such an approach would permit more ATC to be released in real-time and perhaps in earlier time frames (day-ahead, etc.).

10.2 Transmission Rights

Henwood believes that certain existing Point-to-Point (PTP) and Network Transmission (NT) contracts do not lead to an optimal use of the existing transmission system because of a lack of clarity and transparency regarding how to make available unused portions of those rights. Section 9.2 described this matter in some detail. [36]

[36] Since BPA often finds that ATC (or lack thereof) in non-peak load periods is important in its decisions to offer new transmission contracts, it is important to know what transmission needs to be reserved in these periods. The Midwest Independent System Operator (MISO) is addressing this issue by determining what transmission needs to be reserved for network transmission service in each of 4 seasons and each of 2 periods (on-peak and off-peak) in the seasons. These needs are load determined and not determined by generation capability.

Northwest parties can and need to address this problem whether or not an RTO is formed. The Grid West proposal being considered today recognizes that these existing rights will need to be inventoried. However, Grid West does not intend to be the party to inventory these rights. Instead, Grid West intends to give Northwest parties two years to complete this work independently, making it clear that this solution can, and is expected to be, achieved outside of the Grid West framework.

Henwood believes that BPA is already in a position to (a) clarify these issues and (b) develop a process that leads to more transparency on how unneeded or unused transmission rights can be determined and made available to others. Doing so will likely lead to a more robust resale market and more efficient use of the existing transmission system.

10.3 Desirable New Generation Is Not Getting Built

In Henwood's opinion, there do in fact appear to be some renewable projects that are not getting built, partially because of an apparent lack of firm transmission rights. Addressing the problems in 10.1 and 10.2 above should greatly reduce the magnitude of this problem to the extent that it exists today.

10.4 Transmission Rate Pancaking

Henwood's analysis indicates that generation dispatch in the Northwest is not significantly adversely impacted today by transmission rate pancaking. Most transmission has been purchased under long-term contracts, and long-term transmission contracts in the Northwest do not generally involve a volumetric $/MWH charge. Furthermore, many utilities can use the flexibility in their long-term transmission contracts to bring power in from various generating sources without paying additional volumetric $/MWH charges.[37] Although generators will sometimes have contracts with more than one transmission owner, again there is often little or no impact on the day-to-day generation dispatch decisions since these contracts do not have volumetric wheeling charges.[38]

However, as alluded to in Section 9.4, there is an aspect of long-term transmission contract "pancaking" that may create difficulties for some parties in the Northwest. For example, if a developer must contract with multiple transmission owners to carry power

[37] The utilities can use the flexibilities in their PORs under the contract. The only reason use of the flexibilities would not be allowed is if there simply was not any transmission available for the alternative generation. That being the case, even an RTO could not find a way to bring that generation on line without extensive interference in dispatch decisions.

[38] Under these multiple contracts, there may be a "pancaking" of losses. Pancaking of losses implies that each transmission owner is charging for the average losses that actually occur in using his system. If a generator needs to cross several different systems in delivering its power, then losses will be greater than if the power only needs to travel a short distance. Therefore, pancaked loss charges may be a good indicator of the actual incremental cost of dispatch and should be included in the economic dispatch decision.

from its project over long distances, the project may experience a higher cost for its transmission service than if there were a single contract/rate for the entire distance. This is not an issue that results in uneconomic dispatch, but instead is a cost allocation issue. In other words, resolution of this issue is not likely to reduce overall costs on the system – it will likely only affect how much of the costs each party (buyer and seller) will pay.[39]

Similarly, if a utility customer buys power and faces the cost of transmission for delivery, that utility customer would prefer not to have to deal with several different charges. The customer would prefer to have a single (and lower) charge. This is the case currently with a subset of BPA's customers that are served under general transfer agreements (GTAs). Again, this is a cost allocation issue: the costs of the GTAs are currently recovered through BPA's power rates, and any change in this arrangement would shift costs rather than lowering them overall. Resolution of this issue is not likely to reduce overall costs on the system – it will likely only affect how much of the costs each party will pay.

Regional forums and processes already exist to vet cost allocation issues such as those being expressed by GTA customers, and although stakeholders have made attempts to resolve this particular issue, it has not been resolved to the satisfaction of all parties involved. The creation of an RTO is not likely to remove the contentious nature of cost-allocation issues, but will likely only shift the location where the competing interests will make their equity arguments.

Regional stakeholders that are unhappy with current cost allocation methodologies and support Grid West clearly believe an RTO would implement a cost allocation scheme that is more favorable to their situation.[40] However, the cure may be worse than the illness in this case. Henwood has determined in this report that significant net costs would be borne by the region if an RTO were implemented. Costs may decrease for some customers due to reduced transmission pancaking, but increase overall as a result of the establishment of an RTO. This is not an outcome that any regional stakeholder is likely to be happy with.

10.5 No Single OASIS

The problem of (a) no single OASIS, and (b) no single point for information on short-term ATC is a significant problem that an RTO would intend to address. However, an RTO is not required in order to address this issue; it is a problem that is already being

[39] One form of pancaking is evident in BPA's separate charge for the Eastern Interconnect and Southern Intertie. Certainly this pancaking could be eliminated in a BPA rate case if appropriate, although such a change would shift cost recovery among existing BPA transmission customers.

[40] It is not clear how this rate pancaking issue will be resolved in a FERC proceeding. Likely FERC will separate high voltage transmission from lower voltage transmission such that a form of "pancaking" may still occur (i.e. between high voltage and lower voltage transmission facilities). Further, FERC may decide that certain geographic regions of the high voltage grid pay different rates than other geographic regions. Such outcomes have been experienced in other areas of the country.

addressed today through the western OASIS web site – wesTTrans.net. The wesTTrans.net website is an enhanced OASIS site serving a significant portion of the Western Interconnection. Each participating Transmission Provider maintains its own transmission tariff, but collectively the Providers offer a common and more efficient method of accessing the transmission and energy markets within the Western Power Grid.

The wesTTrans.net OASIS also provides significant advancements. An energy bulletin board, a resale interface, and transmission deal automation system are all available for use by the Transmission Customers. Recently, a large number of Northwest transmission system owners have joined wesTTrans.net. While the site seems to show promise as a central point for information, if parties do not post good information on the site, then the site will not be as valuable as it should be. Other enhancements to the wesTTrans.net system would also help make better use of the region's grid.

10.6 No Single Point Of Information On Available Transmission Capacity (ATC)

The wesTTrans.net site discussed above can help solve the problem of consolidating the posting of available transmission capacity with regards to shorter term ATC needs. However, for longer term transmission needs (e.g., 20 years), OASIS sites do not post availability of such transmission. Requests for longer term transmission need to be made via special requests to the transmission owner or owners. In Henwood's opinion, this problem of not having a single point of information on long-term available transmission capacity will likely exist with or without an RTO. (See also section 10.12 on this issue.)

10.7 Contract Path ATC Versus Flow-Based Capacity

It is difficult to quantify inefficiencies that may actually be happening because transmission commitments are being made on a contract path approach instead of a flow-based capacity approach. Such inefficiencies might be evidenced by actual flows being limited by artificially reduced OTC levels established by transmission system operators. However, in the Northwest the evidence is that actual flows generally do not hit OTC limits. It is not apparent that much, if any, efficient generation operation is currently being impaired in day-ahead or real time operations because of a contract approach versus a flow-based approach.

This contract path ATC vs. flow-based capacity issue seems to be largely associated with requests for long-term firm transmission. BPA has already invoked a new flow-based capacity approach with respect to such long term requests and is implementing flow-based calculations of short-term ATC as well. BPA is in fact denying transmission requests because of the flow-based approach and the fact that BPA feels it has already sold the full capacity on several of the paths that would be impacted by the request. It seems that if there is a problem, the problem could be that some entities that have purchased these rights are not fully utilizing them and are not making them available in a resale market. This matter is the subject of section 10.2 above.

10.8 Lack Of Northwest Regional Transmission Planning Authority

Some parties claim that this problem has created a situation in which needed new transmission capacity is not getting built. However, no party seems to be saying that NERC, WECC or NWPP reliability criteria are being violated as a result of this lack of new transmission. Parties claiming that new transmission needs to be built appear to be talking about transmission needs for economic, not reliability, reasons. There is a dispute in the region as to whether these "economic" transmission projects can be justified in a benefit/cost analysis.

The lack of a transmission planning authority is often expressed as an inability today for an isolated utility or committee of transmission planners to require/guarantee construction of a transmission line. The FERC Open Access Transmission Tariff adopted today by all investor-owned utilities and BPA requires transmission owners to build transmission if (a) a request for transmission is made, (b) existing ATC is not available, and (c) the requestor is willing to finance and pay for the transmission under both the FERC transmission pricing approach (the "or" test) and the generation interconnection standards. Of course, even though FERC requires that the transmission be built, FERC does not have the authority to permit these lines, so the FERC requirement may be moot. More problematic is the fact that requestors often can not (or do not want to) finance the construction of the line.

An RTO is often intended to be a conduit for more rigorous regional transmission planning authority. For the Northwest, this more rigorous transmission planning can be accomplished without an RTO by simply enhancing the role of the NWPP Transmission Planning Committee (TPC)[41], funding additional NWPP staff, and requiring more joint transmission planning efforts. Such an enhanced activity would be very much like the role that the CAISO plays in transmission planning in California, but without the ISO overheads.

Grid West bylaws are being written in a manner such that, if there is disagreement among stakeholders regarding the construction and cost allocation of new transmission lines, Grid West may be able to force the construction of those new lines. The bylaws that have been drafted on this matter provide for two distinct steps if agreement is not reached by affected parties. First, the dispute goes to dispute resolution under the bylaws. After that, the dispute is subject to FERC jurisdiction. However, as discussed above, even if

[41] Including its sub-committee, the Northwest Transmission Assessment Committee (NTAC), which is the open forum to address forward looking planning and development for a robust and cost effective Northwest Power Pool area transmission system.

FERC decides the line needs to be built and "orders" a particular cost allocation, FERC still does not have the authority to permit the line.
In the end, it is not clear that formation of an RTO will (or should) result in any different transmission line construction. The better process for ensuring needed transmission lines are built would be a process that invites the participation of all stakeholders and provides an opportunity for parties to fully understand the need for and benefits and costs of the line. Again, Henwood believes this process could be convened by a strengthened NWPP. Where there is strong agreement that lines should be built, then the probability of success is best.

10.9 Ensuring Resource Adequacy And System Reliability

In general, RTOs are not expected to be responsible for ensuring sufficient generation. It appears that the states want to retain this role. Within the Northwest, at present the utilities have the responsibility for ensuring resource adequacy. Often this responsibility is accompanied by a requirement to bring stakeholder involvement into the process through a formal Integrated Resource Plan type of activity. It is Henwood's opinion that there is not currently a significant problem with this current system, given the current surplus of generation capacity in the WECC.[42]

10.10 Need For Enhanced Reliability And Security

Henwood does not see a significant need for enhanced reliability and security in the Northwest today. Few major blackouts have occurred in the Northwest over the last decade. Those that have occurred seem to have happened because certain parties did not comply with WECC reliability criteria, such as ensuring that trees are adequately trimmed. As mentioned in Section 9.10, the Pacific Northwest Security Coordinator (PNSC) has been established to help ensure the reliability of the system, and the PNSC is already ensuring that operating reserves are being met. The effectiveness of the PNSC is only limited by the willingness of participating systems. An RTO would not provide significant additional value. In fact, it is possible that an RTO may even reduce the existing level of reliability (see discussion in Section 6 on unintended consequences).

10.11 Lack Of Market Monitoring

Despite the concern by some that certain parties may be able to unduly influence market prices, the lack of market monitoring does not appear to be a serious problem facing the Northwest today. While BPA and BC Hydro may be situated such that they can unduly

[42] If Northwest states move to Direct Access, the states will need to determine if and how resource adequacy will be assured for direct access customers. A problem resulted in WECC when California moved to Direct Access without determining how resource adequacy would be determined in that environment.

impact market prices, they do not appear to be doing so today on a widespread basis. Further, given that an LMP process has not been implemented in the Northwest, there is not a need to monitor generation dispatch that might be intended to inappropriately impact LMPs. With the construction of significant amounts of new generation in WECC since 2001, competitive forces seem to be keeping prices near cost based levels. Nevertheless, it may be desirable to have a market monitoring function in WECC. A process is already underway to discuss how the WECC can jointly establish and fund a west-wide market monitoring entity. It would not be necessary to form Grid West to establish and fund such an organization.

10.12 Multiple Transmission Queues For Long-Term Service And Interconnection Of New Generation

The existence of multiple transmission queues for long-term service and interconnection does appear to be a problem for some Northwest parties. However, an RTO is unlikely to solve this problem, and may even serve to exacerbate it. For example, before the California ISO was established, a new generator may have been lucky enough to only have to deal with one other party – the owner of the system directly interconnecting the new generation. Under the new CAISO rules, however, both the CAISO and the transmission owner need to be involved when a new generator wants to interconnect. In such a case, the process has not been simplified by formation of an RTO.

With regard to long term transmission service, if it is not possible to provide service out of existing capability, then there needs to be a determination of what would need to be built. As discussed above, if a transmission system owner (or RTO) concludes that existing transmission does not exist, then there will likely be a long process with many stakeholders (e.g., ratepayers, commissioners, regulators, and environmental interests) involved in studies and decisions regarding what should be built, why it needs to be built, and who will pay. Such a process will likely occur with or without an RTO.

10.13 No Day-Ahead Information For Dealing With Congestion

Evidence from recent SSG-WI reports, as well as Henwood's own analysis performed for this study, indicates that congestion is not generally a significant problem on the Northwest power grid. Congestion is more frequent on ties to the South and North. However, congestion occasionally does and will arise in the Northwest grid. It would be beneficial to have day-ahead information indicating that congestion may occur in order to better alleviate such congestion. Generally, the best approach to relieving congestion is to re-dispatch generation in the most economical manner. Although implementing a Locational Marginal Price (LMP) process is one way to accomplish the best re-dispatch, LMP is not the only way to achieve optimal redispatch.

The fact is, there are other ways to achieve optimal redispatch. A congestion management system can be developed in the Northwest without forming an RTO. BPA has identified the need to establish a more definitive day-ahead congestion management system for internal paths on its own system and has started to examine this issue. It is entirely likely, and desirable, that this BPA process will evolve into a process where day-ahead power schedules across the Northwest are made available to BPA (or the PNSC) for load flow modeling. The BPA-initiated process may also define what actions will be taken if congestion is found in this day-ahead analysis. If this is the case, some process will need to identify how any cost of redispatch (that might result from the day-ahead analysis) will be allocated. This activity can occur without an RTO and will likely need greater specificity of Transmission Rights (Section 10.2 above).

10.14 Control Area Inefficiencies

It is unclear whether the lack of an automatic reserve sharing market is creating significant inefficiencies in the Northwest. Henwood recommends that the region survey its control area operators to determine the extent of any problems associated with the current practice of reliance on bi-lateral contracts to meet reserve requirements. If the problem is such that bi-lateral contracting does not result in the most efficient provision of operating reserves, then the Reserve Sharing agreement that exists in the Northwest today can be modified to accomplish the efficiencies. Finding solutions to this problem does not require the formation of an RTO. The PNSC has all the information to accomplish the more efficient provision of reserves, and can help identify opportunities for control area operators to achieve greater efficiency in this area. What they would need is an agreement on the cost sharing and equity issues.

11 WORK PLAN FOR EVALUATING ALTERNATIVES TO TODAY'S TRANSMISSION PROBLEMS WITHOUT AN RTO

As discussed in Chapter 10, solutions exist for many of the transmission problems being experienced in the Northwest that do not involve the creation of an RTO. Many of these solutions, such as the development of a common OASIS, are already being developed at little additional cost. For some of the other measures identified in this report, the costs and benefits of these alternate solutions should be evaluated by Northwest transmission stakeholders. Henwood believes that the following analysis would be beneficial to perform:

- Calculate the comparative cost of solving congestion with a redispatch approach rather than through construction of transmission lines. This type of analysis has been performed in other parts of the country and can be performed in the Northwest. This would likely be no more than a two month effort.

- Determine the expected cost of re-dispatch that will allow loads to be served rather than curtailed. Once these expected cost levels are determined, parties can better determine how to allocate such costs to the extent that firm rights exceed the ability of the system. Knowing the expected magnitude of the cost may facilitate negotiations on cost allocations. This would likely be no more than a two month effort and could be done concurrently with the work above.

- Analyze the economic benefits or burdens to a transmission right holder of selling part of those rights. Certain rights (or portions of those rights) may have little value to the rights holder. Tariff modifications could help increase opportunities for the resale of unneeded rights. This would likely be no more than a two month effort and could be done concurrently with the work above.

- Determine the economics of allowing new generators to gain access to the existing grid through a transmission rights re-sale process rather than a process that requires the generator to fund new transmission. This would likely be no more than a two month effort and could be done concurrently with the work above.

12 CONCLUSION

The Northwest is unique in that 75 percent of the region's transmission is owned by one entity -- BPA. Largely as a result of this singular situation, the analysis conducted by Henwood indicates that the costs of forming and operating an RTO in the Northwest will likely exceed the benefits. Moreover, there appears to be significant risk and unquantifiable costs associated with RTOs that the region should consider prior to moving forward with any proposed RTO structure. There are good reasons to address current transmission problems today, but this report suggests that focus should be in those areas rather than in an effort to form an RTO. Resolution of these immediate problems today will provide more benefits to residents of the Northwest than will an effort to form an RTO.

APPENDIX A: CONTRACT PATH SCHEDULING LIMITS

Cutplane No.	A							
Cutplane Name	Northwest-Canada WECC Path 3							
Path	RTC N-S	3100	RTC S-N	2000	OTC N-S	2300	OTC S-N	2000
Link name								
BC – Seattle North					OTC N-S	1800	OTC S-N	1550
BC – North Puget					OTC N-S	300	OTC S-N	250
BC – Spokane					OTC N-S	200	OTC S-N	200

Cutplane No.	B							
Cutplane Name	Monroe-Echo Lake – No WECC Rating							
Path	RTC N-S	2500	RTC S-N	2500	OTC N-S	2500	OTC S-N	2500
Link name								
North Puget – Seattle North					OTC N-S	400	OTC S-N	400
BC – Seattle North					OTC N-S	2100	OTC S-N	2100

Cutplane No.	C							
Cutplane Name	Raver-Echo Lake – No WECC Rating							
Path	RTC N-S	1800	RTC S-N	1800	OTC N-S	1800	OTC S-N	1800
Link name								
Seattle South – Seattle North					OTC N-S	1800	OTC S-N	1800

Cutplane No.	D							
Cutplane Name	West of Cascades North WECC Path 4							
Path	RTC N-S	10200	RTC S-N	10200	OTC N-S	9800	OTC S-N	9800
Link name								
Coulee – North Puget					OTC N-S	2200	OTC S-N	2200
Coulee – Seattle North					OTC N-S	1800	OTC S-N	1800
Coulee – Olympia					OTC N-S	400	OTC S-N	400
Coulee – Seattle South					OTC N-S	5400	OTC S-N	5400

Cutplane No.	E							
Cutplane Name	West of Hatwaii WECC Path 6							
Path	RTC N-S		RTC S-N		OTC N-S		OTC S-N	

		3600		3600		3327		3327
Link name								
Spokane – Coulee					OTC N-S	200	OTC S-N	200
Spokane – Columbia Basin					OTC N-S	200	OTC S-N	200
Spokane – Snake					OTC N-S	200	OTC S-N	200
Garrison – Coulee					OTC N-S	1818	OTC S-N	1818
BPA Montana – Coulee					OTC N-S	909	OTC S-N	909

Cutplane No.	F							
Cutplane Name	North of Hanford – No WECC rating							
Path	RTC N-S	3700	RTC S-N	3700	OTC N-S	3500	OTC S-N	3500
Link name								
Coulee – Columbia Basin					OTC N-S	3500	OTC S-N	3500

Cutplane No.	G							
Cutplane Name	South of Raver – No WECC rating							
Path	RTC N-S	3050	RTC S-N	3050	OTC N-S	1920	OTC S-N	1920
Link name								
Seattle South – Olympia					OTC N-S	1520	OTC S-N	1520
Coulee – Olympia					OTC N-S	400	OTC S-N	400

Cutplane No.	H							
Cutplane Name	South of Paul – No WECC rating							
Path	RTC N-S	2960	RTC S-N	2960	OTC N-S	2960	OTC S-N	2960
Link name								
Olympia – Wilswa					OTC N-S	2960	OTC S-N	2960

Cutplane No.	I							
Cutplane Name	Montana to Northwest WECC Path 8							
Path	RTC EW	2200	RTC WE	1350	OTC EW	2200	OTC we	1350
Link name								
Garrison – West Montana					OTC N-S	132	OTC S-N	81
Garrison – Spokane					OTC N-S	250	OTC S-N	153
Garrison – Coulee					OTC N-S	1818	OTC S-N	1116

Cutplane No.	J

Cutplane Name	West of Noxon – No WECC rating						
Path	RTC N-S	3400	RTC S-N	3400	OTC N-S	3400	OTC S-N 3400
Link name							
Garrison – Spokane			OTC N-S	250	OTC S-N	250	
West Montana – Spokane			OTC N-S	423	OTC S-N	423	
Garrison – Coulee			OTC N-S	1818	OTC S-N	1818	
BPA Montana – Coulee			OTC N-S	909	OTC S-N	909	

Cutplane No.	K							
Cutplane Name	LoLo – No WECC rating							
Path	RTC N-S	275	RTC S-N	325	OTC N-S	275	OTC S-N	325
Link name								
So Idaho – McNary				OTC N-S	275	OTC S-N	325	

Cutplane No.	L							
Cutplane Name	Idaho Montana – No WECC rating							
Path	RTC N-S	337	RTC S-N	337	OTC N-S	337	OTC S-N	337
Link name								
Eastern Idaho – Garrison				OTC N-S	337	OTC S-N	337	

Cutplane No.	M							
Cutplane Name	North of John Day WECC Path 73							
Path	RTC N-S	8400	RTC S-N	8400	OTC N-S	8200	OTC S-N	8200
Link name								
Seattle South – Olympia				OTC N-S	1520	OTC S-N	1520	
Coulee – Olympia				OTC N-S	400	OTC S-N	400	
Columbia Basin – Wilswa				OTC N-S	1500	OTC S-N	1500	
Columbia Basin – the Dalles				OTC N-S	2055	OTC S-N	2055	
Columbia Basin – Snake				OTC N-S	2400	OTC S-N	2400	
Columbia Basin – So Idaho				OTC N-S	325	OTC S-N	325	

Cutplane No.	N							
Cutplane Name	Enterprise – No WECC rating							
Path	RTC N-S	375	RTC S-N	375	OTC N-S	325	OTC S-N	325
Link name								
So Idaho – Columbia Basin				OTC N-S	325	OTC S-N	325	

Cutplane No.	O							
Cutplane Name	Idaho to Northwest WECC Path 14							
Path	RTC N-S	2400	RTC S-N	2400	OTC N-S	2200	OTC S-N	2200
Link name								
Wyoming West – So Oregon			OTC N-S	1500		OTC S-N		1500
So Idaho – McNary			OTC N-S	325		OTC S-N		325
So Idaho – Columbia Basin			OTC N-S	375		OTC S-N		375

Cutplane No.	P							
Cutplane Name	West of Cascades South – No WECC rating							
Path	RTC N-S	7000	RTC S-N	7000	OTC N-S	7000	OTC S-N	7000
Link name								
Columbia Basin – Wilswa			OTC N-S	1500		OTC S-N		1500
The Dalles – Wilswa			OTC N-S	2600		OTC S-N		2600
North Central Oregon – Wilswa			OTC N-S	2700		OTC S-N		2700
McNary – Wilswa			OTC N-S	200		OTC S-N		200

Cutplane No.	Q							
Cutplane Name	West of John Day (Slatt) – No WECC rating							
Path	RTC N-S	6900	RTC S-N	6900	OTC N-S	5000	OTC S-N	5000
Link name								
North Central Oregon – Wilswa			OTC N-S	2700		OTC S-N		2700
North Central Oregon – the Dalles			OTC N-S	2100		OTC S-N		2100
McNary – Wilswa			OTC N-S	200		OTC S-N		200

Cutplane No.	R							
Cutplane Name	West of McNary – No WECC rating							
Path	RTC N-S	2650	RTC S-N	2650	OTC N-S	2650	OTC S-N	2650
Link name								
McNary – North Central Oregon			OTC N-S	2450		OTC S-N		2450
McNary – Wilswa			OTC N-S	200		OTC S-N		200

Cutplane No.	S							
Cutplane Name	LaGrande – No WECC rating							
Path	RTC N-S		RTC S-N		OTC N-S		OTC S-N	

		275		325		275	325
Link name							
So Idaho – McNary			OTC N-S	275	OTC S-N		325

Cutplane No.	U						
Cutplane Name	Midpoint Summer Lake – WECC Path 75						
Path	RTC EW	1500	RTC WE	650	OTC WE	1500	OTC WE	650
Link name								
Wyoming West – So Oregon			OTC E-W	1500	OTC W-E		650

Cutplane No.	V							
Cutplane Name	COI – WECC Path 66							
Path	RTC N-S	4800	RTC S-N	3675	OTC N-S	4000	OTC S-N	2500Su 3500Wi
Link name								
COB – CNP15			OTC N-S	4000	OTC S-N			2500Su 3500Wi

Cutplane No.	W							
Cutplane Name	PDCI – WECC Path 65							
Path	RTC N-S	3100	RTC S-N	3100	OTC N-S	3100	OTC S-N	3100
Link name								
The Dalles – LADWP			OTC N-S	3100	OTC S-N			3100

Cutplane No.	X							
Cutplane Name	Reno Alturas WECC Path 76							
Path	RTC N-S	300	RTC S-N	300	OTC N-S	300	OTC S-N	300
Link name								
COB – N Nevada			OTC N-S	300	OTC S-N			300

APPENDIX B: NEW GENERATION

Trans Area	Unit Name	Unit No	Installation Date	Max Rating	Fuel	Unit Type
ALBTS	Benign Pincher Creek	1	1/1/2004	24.4	Wind	WT
BRITC	Gabriola Reefs Wind	1	1/1/2004	60	Wind	WT
PV	Mesquite CC	3	1/1/2004	312.5	Gas	CC
PV	Mesquite CC	4	1/1/2004	312.5	Gas	CC
GARRIS	Whitehall	1	1/1/2004	22.05	Wind	WT
CO_East	Rocky Mountain EC	1a	5/1/2004	300.5	Gas	CC
CO_East	Rocky Mountain EC	1b	5/1/2004	300.5	Gas	CC
CNP15	Clearwood Geothermal	1	6/1/2004	25	Geothermal	ST
S Nevada	Table Mountain Wind	1	6/1/2004	27	Wind	WT
CNP15	Vallejo Wind	1	6/1/2004	19.5	Wind	WT
LADWP	Pine Tree Wind	1	7/1/2004	40	Wind	WT
S Nevada	Silverhawk	1a	7/1/2004	285	gas	CC
S Nevada	Silverhawk	1b	7/1/2004	285	gas	CC
DALLES	Goldendale	1	9/1/2004	253	Gas	CC
Utah	Payson	1a	9/1/2004	141	Gas	CC
N Nevada	ATS Hazen	1	12/1/2004	30	Geothermal	ST
N Nevada	Ely Wind	1	12/1/2004	15	Wind	WT
ABTN	Genesee	3	12/1/2004	450	Coal	ST
LADWP	Haynes Repower	1a	12/1/2004	287.5	gas	CC
LADWP	Haynes Repower	1b	12/1/2004	287.5	Gas	CC
Utah	Stockton Bar	1	1/1/2005	7.5	Wind	WT
GARRIS	WindPark	1	1/1/2005	60	Wind	WT
BRITC	Prince George	1	2/1/2005	48	Gas	CC
N Nevada	ATS Gerlach	1	6/1/2005	35	Geothermal	ST
N Nevada	ATS Gerlach	2	6/1/2005	35	Geothermal	ST
N Nevada	ATS Gerlach	3	6/1/2005	35	Geothermal	ST
SIDAHO	Bennet Mtn	1	6/1/2005	184	Gas	CC
CSCE	Mountainview CC	1a	6/1/2005	264	Gas	CC
CSCE	Mountainview CC	1b	6/1/2005	264	Gas	CC
CSCE	Mountainview CC	2a	6/1/2005	264	Gas	CC
CSCE	Mountainview CC	2b	6/1/2005	264	Gas	CC
CNP15	Metcalf Energy	1a	7/1/2005	301	Gas	CC
CNP15	Metcalf Energy	1b	7/1/2005	301	Gas	CC
N Nevada	ATS Reno	2	9/1/2005	45	Geothermal	ST
IID	Salton Sea 6	n1	10/1/2005	185	Geothermal	ST
GARRIS	Rocky Mtn Power	1	12/1/2005	116	Coal	ST

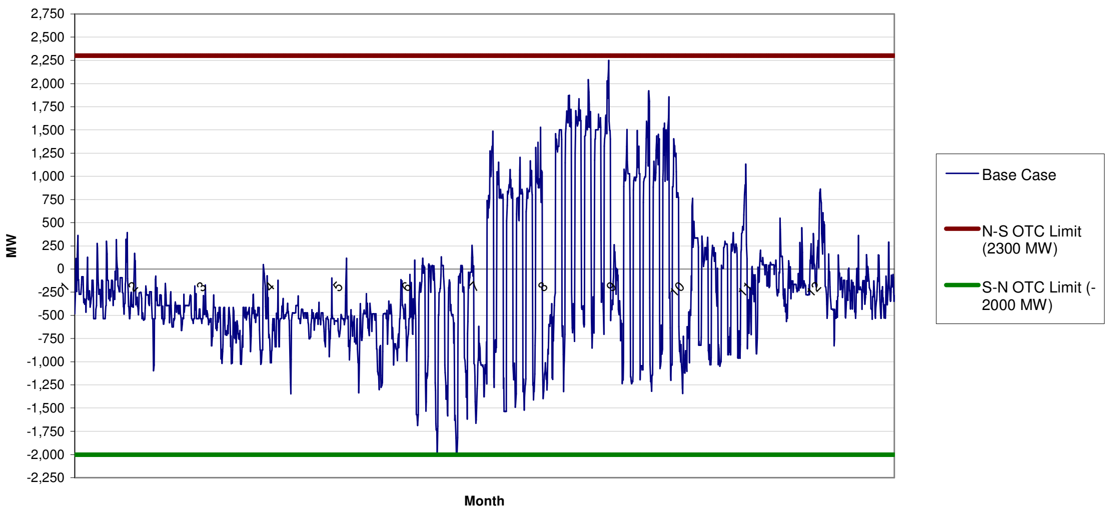
Trans Area	Unit Name	Unit No	Installation Date	Max Rating	Fuel	Unit Type
N Nevada	Blue Mountain Geothe	1	1/1/2006	28.5	Geothermal	ST
Utah	Currant Creek	1a	1/1/2006	245	Gas	CC
Utah	Currant Creek	1b	1/1/2006	245	Gas	CC
BRITC	Nai Kun Wind Park	n1	1/1/2006	105	Wind	WT
OLY	Port Westward	1	1/1/2006	350	Gas	CC
CNP15	Walnut Energy	1	5/1/2006	285	Gas	CC
N Nevada	ATS Redfield	1	6/1/2006	11	Geothermal	ST
S Nevada	Moapa	1a	6/1/2006	285	Gas	CC
S Nevada	Moapa	1b	6/1/2006	285	Gas	CC
CSDGE	Palomar	1a	6/1/2006	285	Gas	CC
CSDGE	Palomar	1b	6/1/2006	285	Gas	CC
N Nevada	ATS Gerlach	4	12/1/2006	35	Geothermal	ST
N Nevada	ATS Gerlach	5	12/1/2006	35	Geothermal	ST

APPENDIX C: HOURLY INTERFACE LOADINGS

Appendix C of this report shows loadings on the key cutplanes in the Northwest under both a Base Case and a Grid West case. These line loadings come from the PowerWorld model using generation dispatch developed by MarketSym zonal analysis. The purpose of running PowerWorld in this mode is to test to see if overloads occur in a network model when the zonal dispatch is input to the network model. In this case, PowerWorld was not run in OPF mode (see earlier discussion).[43]

Base Case

Figure C- 1
Canada to Northwest (Path A)
Base Case



[43] As can be seen in Appendix C there are just a few hours in the study period when zonal analysis results in path ratings being exceeded. The only occurrences are on the transmission lines to California and occur in both the Base Case and the Grid West case. It is likely that the overloads would be solved by simply redispatching hydro on these few hours so that on these few hours less hydro would generate and more generation in California would be called upon. Then in a few later hours there would be more hydro in the Northwest and less in the Southwest. Since the Base Case and the Grid West case reflect the same situation, the difference in the two cases would be essentially unaffected by causing this re-dispatch, hence the redispatch has not been done for this study and there is no impact on the study results as a result of not doing this redispatch.

Figure C- 2
West of Cascades – North
Base Case

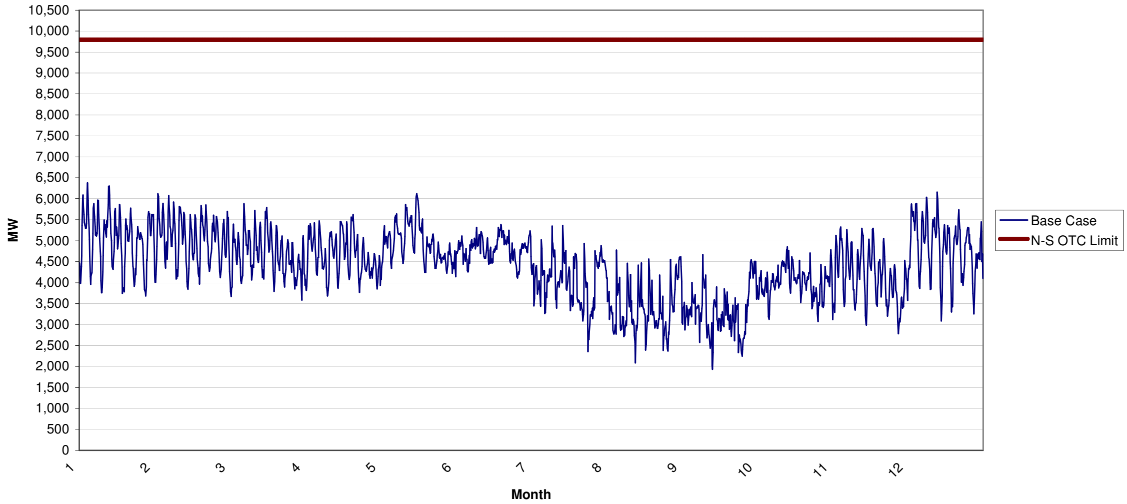


Figure C- 3
West of Hatwai (Path E)
Base Case

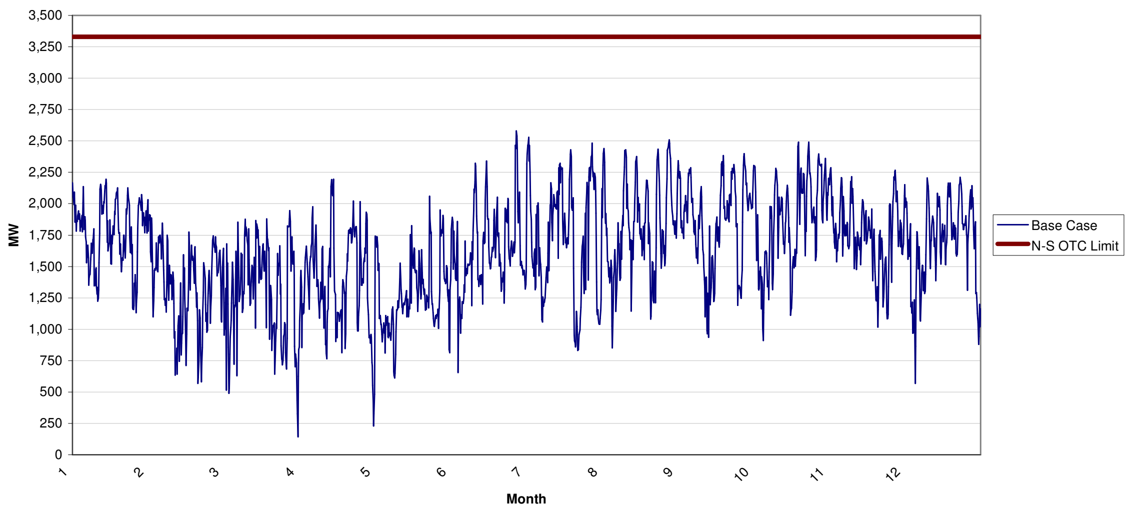


Figure C- 4
North of Hanford (Path F)
Base Case

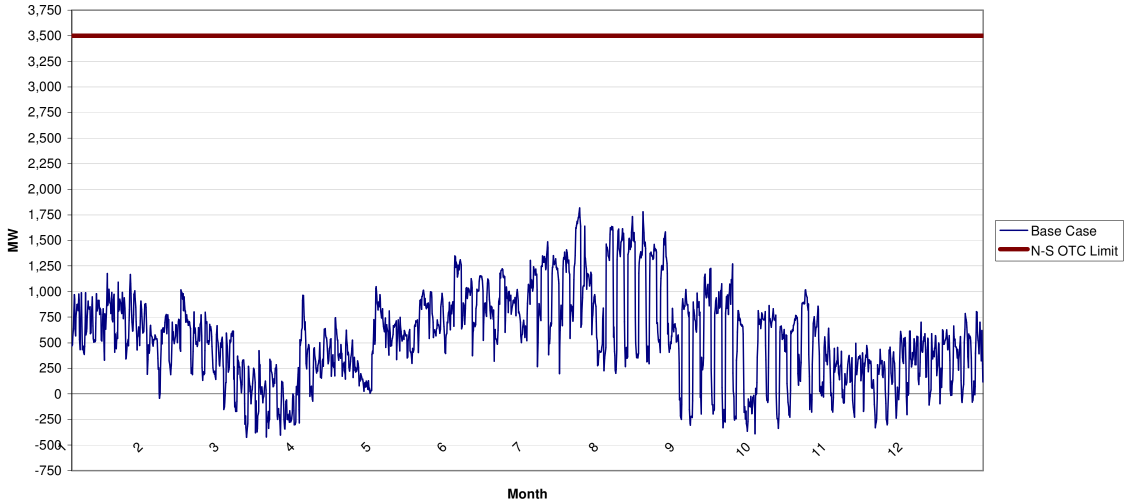


Figure C- 5
Montana to Northwest (Path I)
Base Case

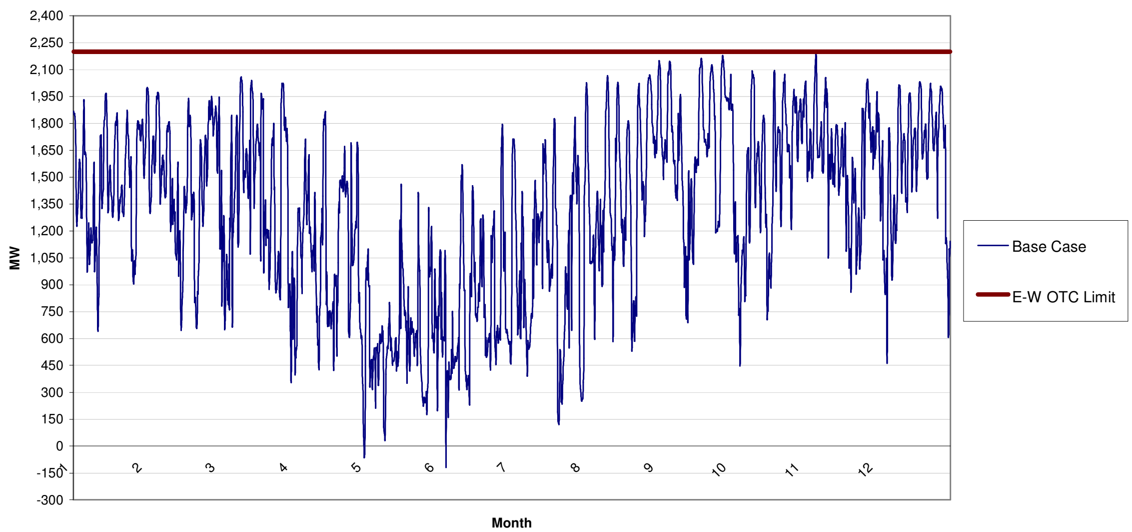


Figure C- 6
North of John Day (Path M)
Base Case

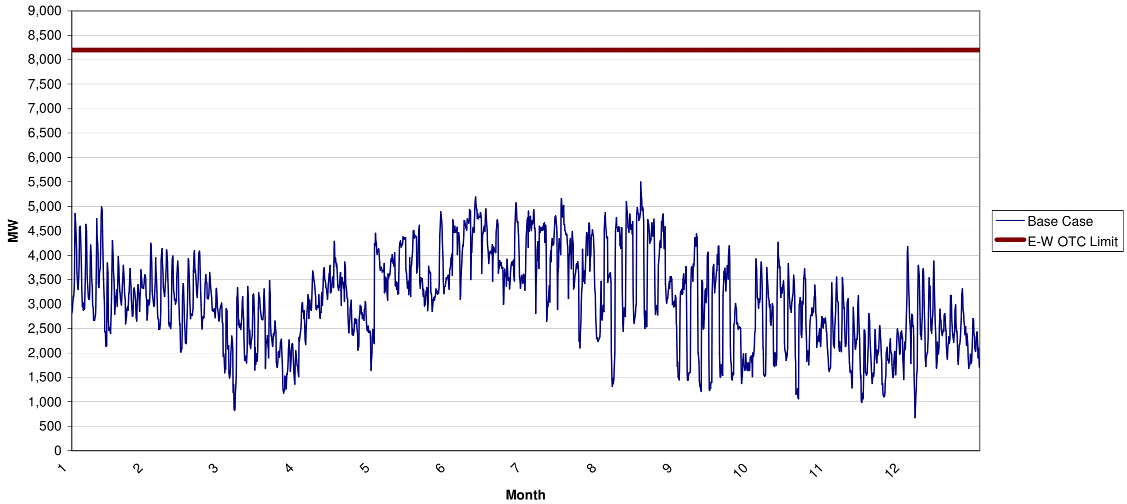


Figure C- 7
West of Cascades – South
Base Case

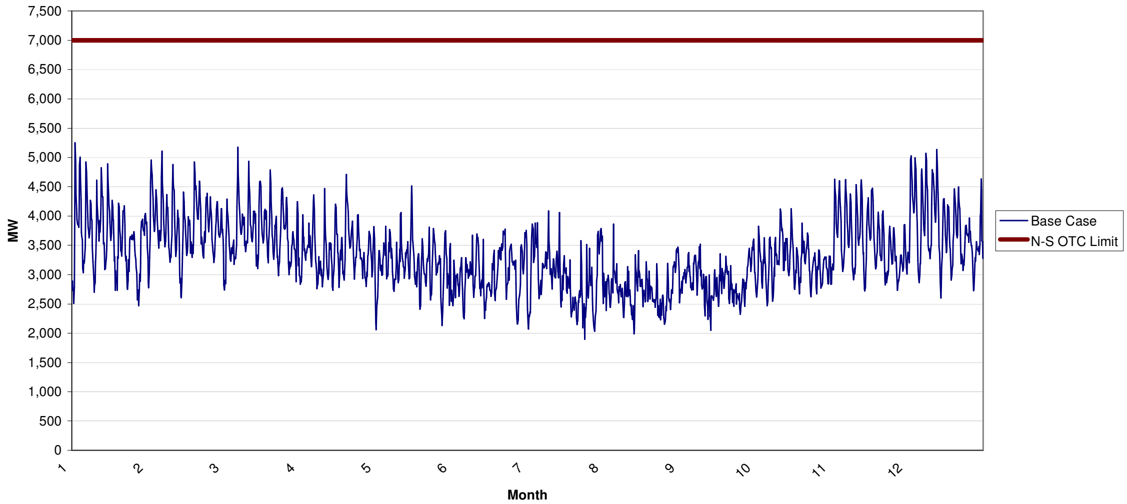


Figure C- 8
West of McNary (Path R)
Base Case

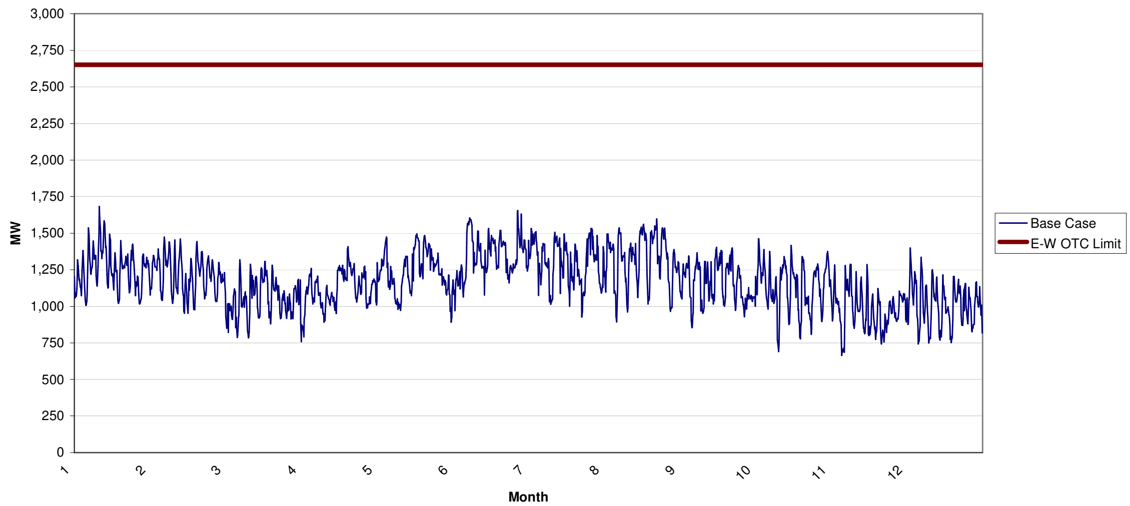


Figure C- 9
Midpoint to Summer Lake (Path U)
Base Case

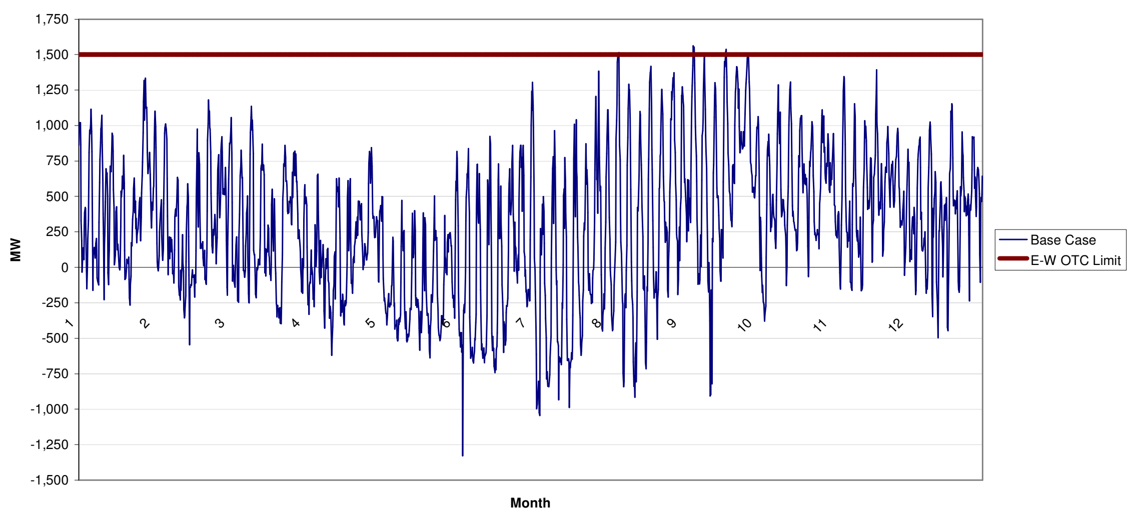


Figure C- 10
COI (Path V)
Base Case

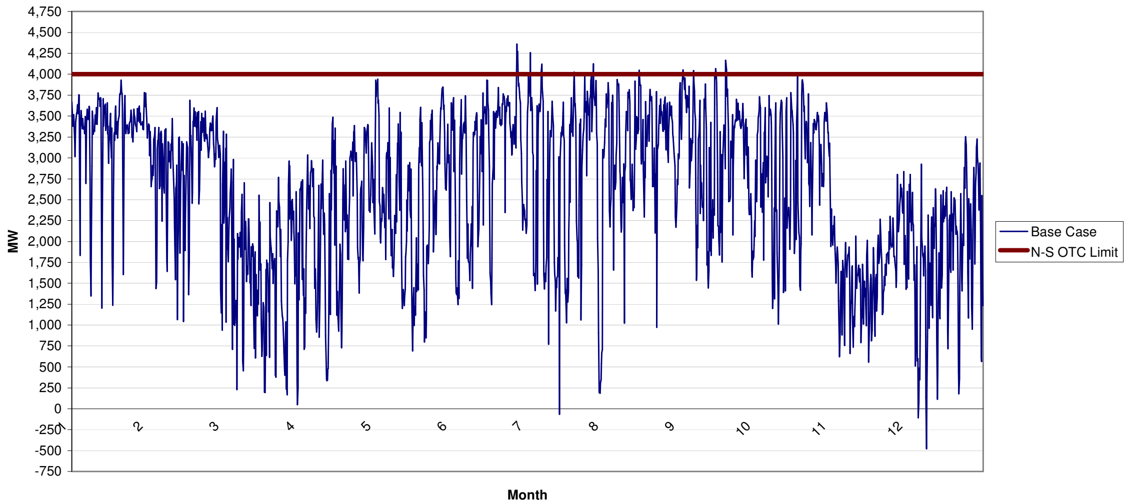
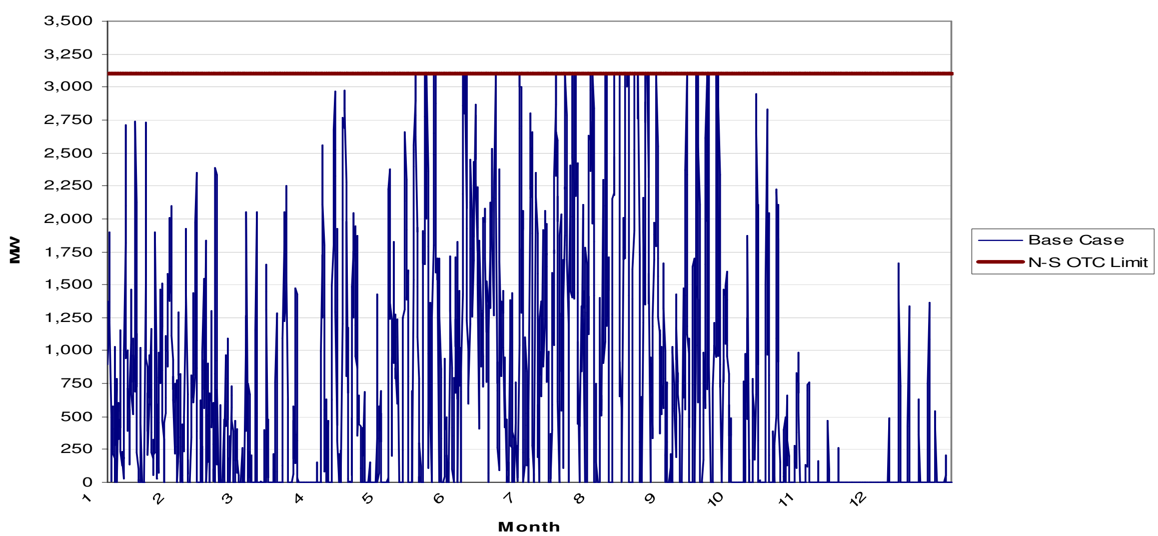


Figure C- 11
Pacific DC Intertie (Path W)
Base Case



Grid West Case

Figure C- 12
Canada to Northwest (Path A)
Grid West Case

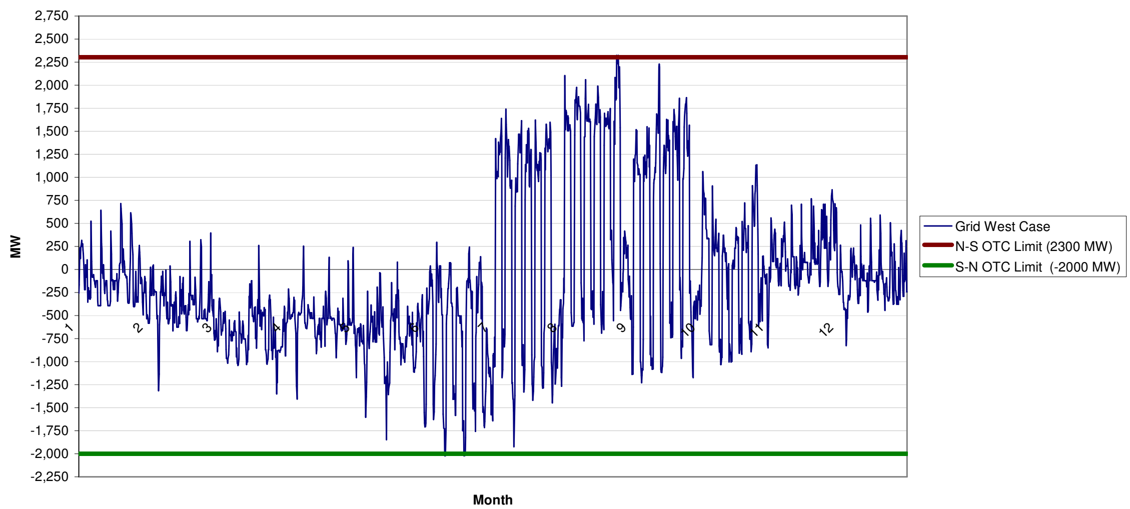


Figure C- 13
West of Cascades – North (Path D)
Grid West Case

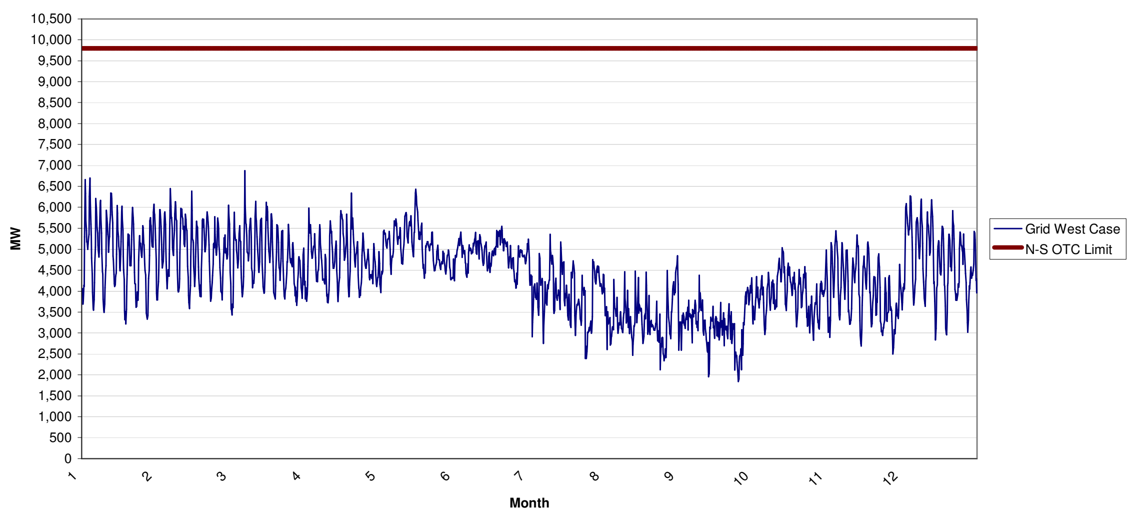


Figure C- 14
West of Hatwai (Path E)
Grid West Case

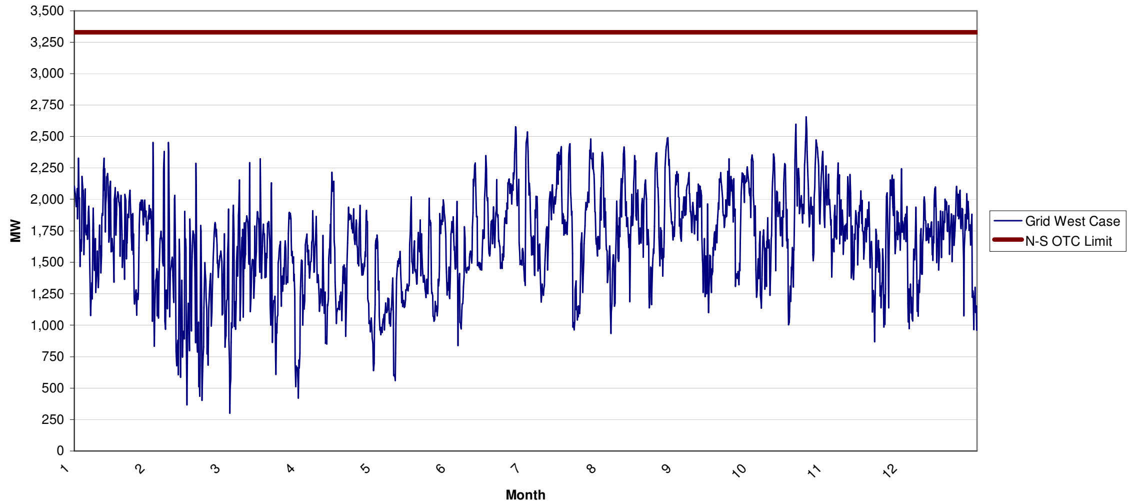


Figure C- 15
North of Hanford (Path F)
Grid West Case

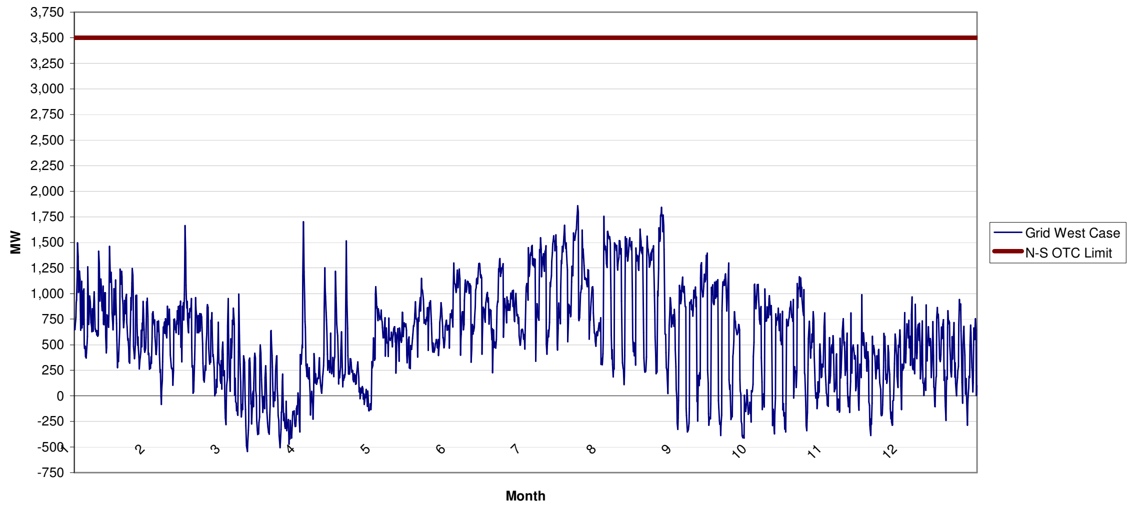


Figure C- 16
Montana to Northwest (Path I)
Grid West Case

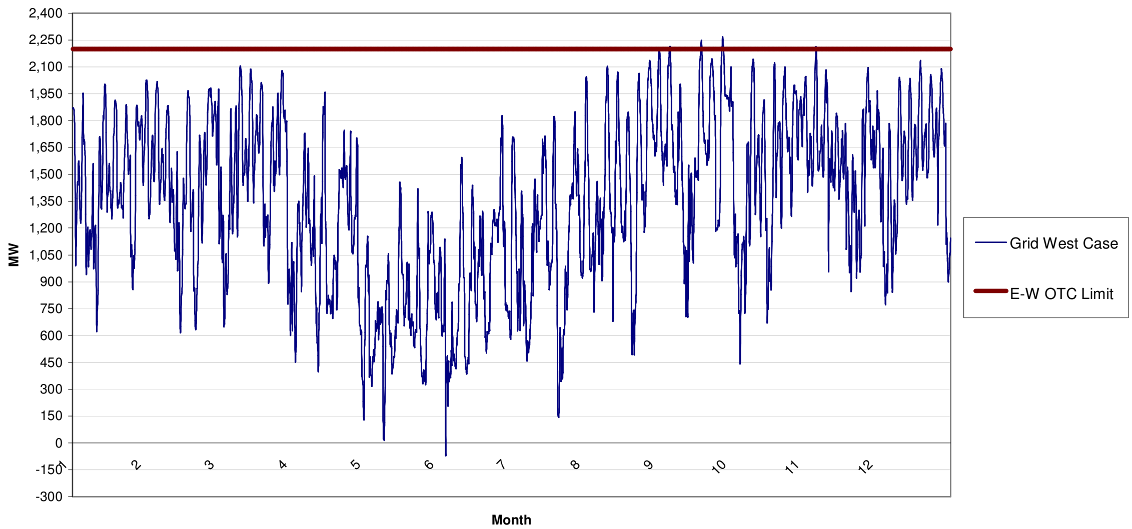


Figure C- 17
North of John Day (Path M)
Grid West Case

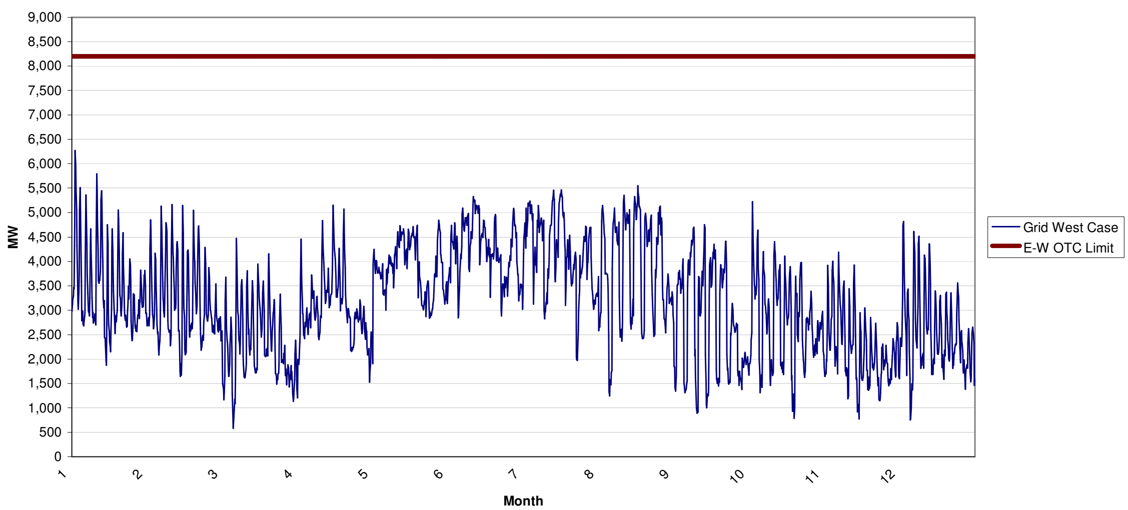


Figure C- 18
West of Cascades – South (Path P)
Grid West Case

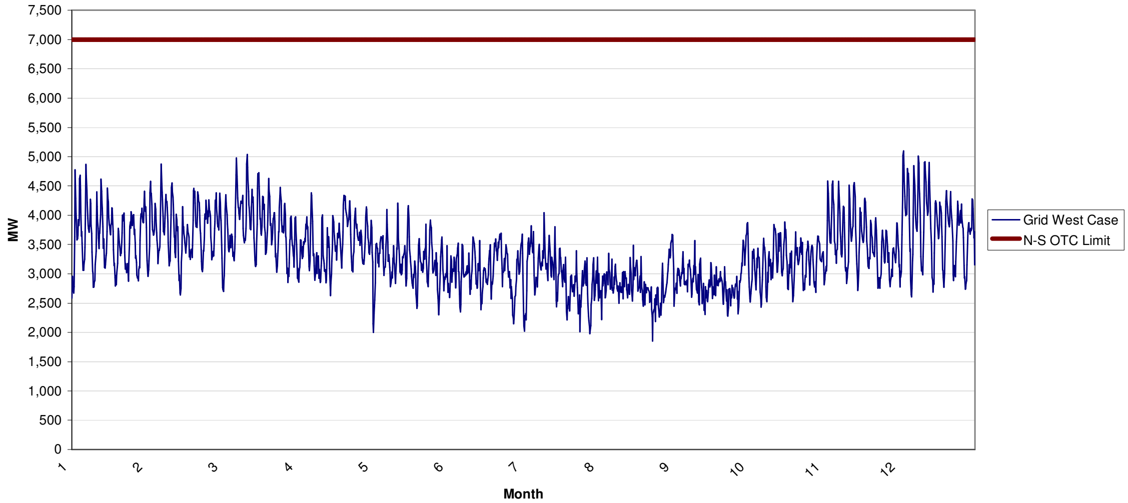


Figure C- 19
West of McNary (Path R)
Grid West Case

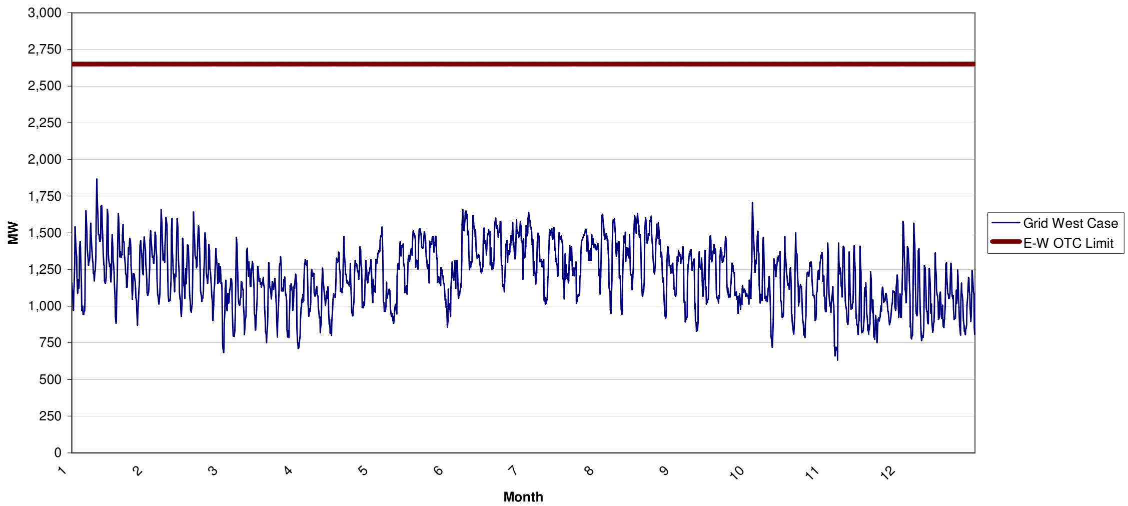


Figure C- 20
Midpoint to Summer Lake (Path U)
Grid West Case

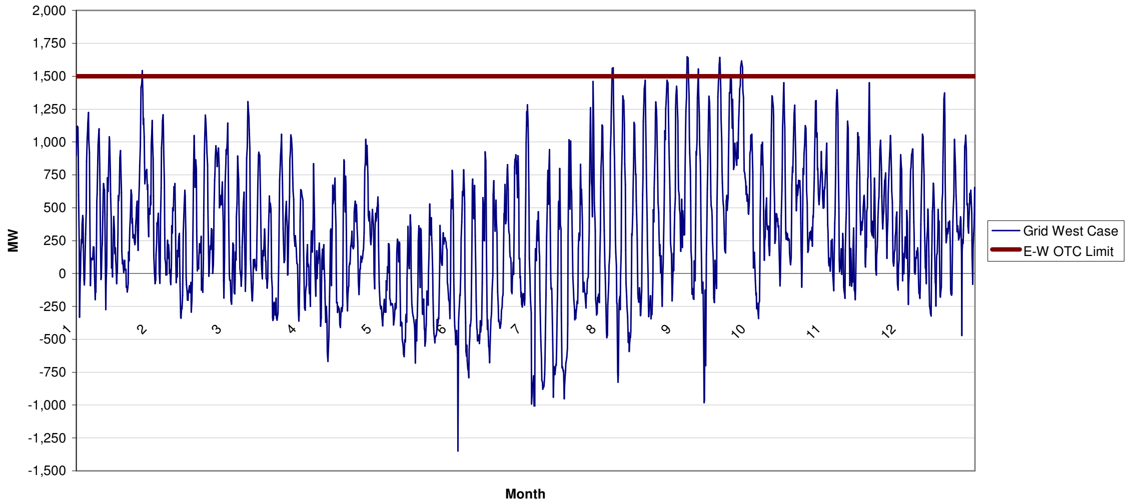


Figure C- 21
COI (Path V)
Grid West Case

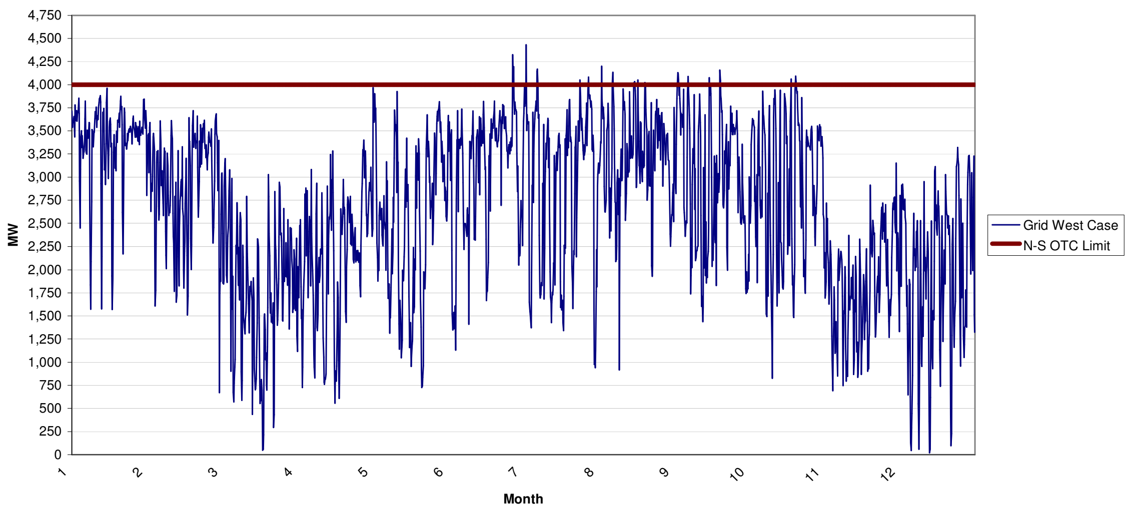


Figure C- 22
Pacific DC Intertie (Path W)
Grid West Case