RTO West

Potential Benefits and Costs

Final Draft

October 23, 2000

EXECUTIVE SUMMARY

This report summarizes the results of attempting to identify and quantify benefits and costs to the regional electric power system that would occur as a result of implementing RTO West. Some, such as savings in regulating reserves and reliability improvements, have been quantified, while the value of eliminating pancaked rates via the RTO West pricing model is currently being examined. Other benefits and costs are discussed, but a lack of precise information has made it difficult to quantify these impacts. A discussion of their qualitative benefits and costs has been included. This report also contains an overview of start-up and annual operation costs for RTO West.

In quantifying its impacts, the RTO Benefits and Costs Team assumed RTO West would include British Columbia Hydro and that the RTO will perform as envisioned. To quantify the economic impacts on the power system, it used the AURORA model. The value of this model is discussed below, as are its limitations. In general, benefits and costs of RTO West are estimated to be:

- Regulating reserve savings are estimated to be 364 MW or approximately $28 million annually based on BPA tariff rates for this product. These savings come from taking advantage of the load diversity of the larger RTO control area (295 MW savings) and taking advantage of recent North American Electric Reliability Council (NERC) standards for a relaxation of regulation requirements (69 MW).

- The RTO Benefits and Cost Team has expended significant effort in attempting to model the effects that removal of pancaked rates within the RTO region would have on the market prices of electricity within the Western Systems Coordinating Council (WSCC). We have attempted to simulate the pricing decisions made including the company rates and the transmission transfer payments between RTO parties. To date, we have determined that:
    - Removal of the friction between the companies' transmission systems tends to lower market pricing in areas of current high prices and tends to raise them in areas of relatively lower prices. This will have differential impacts on loads, integrated utilities and independent power producers.
    - Due to more efficient dispatch, there is a modest fuel savings (on the order of $30 million annually) in the WSCC area as a result of implementing the RTO.
    - Generators that are currently available for service should be dispatched more efficiently, thereby delaying future generation expansion.

    Because of the modifications we have made to the AURORA model, the study results have produced significantly different results for small changes in input assumptions. We cannot, at this time, produce reliable conclusions as a result of this modeling effort. We believe, however, that the likely shifts in power prices are of sufficient importance to market participants to warrant continued examination.

- The value of improved reliability is estimated to range from $33 to $328 million annually. The RTO should improve reliability because it will manage and operate the entire grid. That is, RTO West will have broad geographic visibility of the grid under its operational control. These changes should reduce the likelihood of cascading or system-wide power outages and provide more rapid restoration following an outage. In addition, RTO West will have clear planning authority with an ability to ensure system investments are made if they are needed for reliable service to load.

- The annual costs of implementing a regional RTO, assuming 501(c)3 tax-exempt status, is estimated to be about $63 million, which includes $13 million amortization of start-up costs of the $82 million initial cost. These costs include computer systems, communications, support contracts, facilities and staffing at a level of 277. If the start-up costs exceed this initial estimate by 100 percent, the annual cost would increase to $76 million. Reserves for capital or operating contingencies could raise the revenue requirement of RTO West to a total of $89 million.

Qualitative benefits of RTO West include the expectation it will facilitate more appropriate market signals, increase trading, provide savings and efficiencies by shopping at one open access same time information system (OASIS) for reservations and purchases of RTO transmission services. In addition, it is expected to provide benefits from changes in the way it will manage transmission congestion, improve reliability of the transmission system through clear planning authority and greater visibility of the grid, and reductions in filing utility staffs.

Qualitative costs include the cost of having to retain a schedule coordinator at some utilities, the cost of operating secondary markets for transmission rights over constrained paths, the risk to some loads of exposure to market-based ancillary services prices and the market imperfections that may occur should this RTO get the market rules wrong.

COMPREHENSIVE OVERVIEW

This report summarizes our efforts to identify and quantify benefits and costs the RTO West would bring to the regional electric power system. It was prepared by the RTO Benefits and Costs Team. Both the benefits and costs are needed to understand the potential net value of establishing a regional transmission organization, as opposed to the current independent transmission systems with numerous control areas, transmission owners and business practices. Not only are the quantified costs and benefits reported here, but other potential unquantified costs and benefits are also discussed.

This report incorporates an overview of start-up and annual operation costs for RTO West, which have been prepared by the RTO Implementation Team (a detailed implementation cost analysis can be found in the Implementation Team report).

Though the information here reflects the excellent efforts of many workgroups, we recognize that identifying costs and benefits is not a precise science and many assumptions were made to arrive at the information presented herein.

The key assumptions of the work group's analyses are:

- That the filing utilities plus British Columbia Hydro will form RTO West. If any of the individual parties do not participate, the quantitative analyses would differ.

- That the RTO West performs as envisioned. That is, it meets its stated operating cost estimates, provides no unintended impediments to power and ancillary-service market development, plans correctly, avoids the socialization of costs when directly assigning them would provide better economic efficiency, and establishes prices that promote economic efficiency.

- The AURORA model as modified for this effort will provide reasonable estimates of the economic impacts of changes in transmission pricing. (AURORA is a regionally-accepted model that has been used to consider the benefits and costs among Northwest customers, including BPA and other West coast users.)

- The Team chose AURORA to estimate the economic impacts of de-pancaking transmission rates. As in any model, AURORA makes simplifying assumptions. For both the with- and without-RTO cases, it assumes that competitive market prices in each area drive dispatch and generation capacity expansion decisions. AURORA's most significant assumptions are:
  - It assumes average water, average unit performance, expected hourly loads and expected fuel prices. While some say the use of average

assumptions could skew results, others believe that using the same assumption in both the pre-RTO and post-RTO cases eliminates most of the problems with the assumption.

- It assumes pricing reciprocity between neighboring systems (no charge for through-wheeling for service to external loads).
- AURORA assumes all transactions for power are made at the market clearing price. We have attempted to recognize that not all transactions are made at the market clearing price by netting generation and loads. Some think this is a significant assumption, while others think it has nothing to do with the model results .
- It underestimates transmission constraints. It does not represent all constrained paths within the WSCC. (These paths' limits change seasonally and with equipment outages.) We have attempted to use reasonable limits for critical seasons for the paths that are represented.
- It is not an operational model and does not attempt to reflect dynamic transmission congestion.
- It assumes static transmission capacity: no expansion or relief of constrained paths is made through transmission investments. Instead, congestion relief is accomplished through cost-effective generation additions. Although this could negatively affect the results, some on the Team believe there is no significant change in the way transmission upgrades will be financed in the RTO and non-RTO world, so there may be little impact on the model outcome if static transmission capacity is not included.
- The model assumes that the only impact on efficiency and competitiveness results from eliminating rate pancaking. It assumes the same level of trading liquidity and price discovery with and without an RTO.
- It assumes unrestricted availability of gas supply for the resources it predicts will be built. Some of the Team believes that the gas-supply assumption could affect the AURORA results. Others believe this assumption may have little effect, because it affects both the RTO and non-RTO cases equally.

- That the savings identified would not have been accomplished or costs incurred absent formation of RTO West.

Benefits and Costs

The Benefits and Costs Team compiled a list of both quantitative and qualitative benefits and costs. Assuming concerns of AURORA modeling are resolved, we expect to be able to quantify load and supplier power cost impacts and fuel savings, and the changes to generation capacity expansion due to the elimination of pancaked transmission rates. The Team has quantified the benefit of the reduction in the number of megawatts needed for power system regulating reserves and a range of reliability benefits due to avoided outages or reduced outage duration.

The report only describes qualitatively many costs and benefits, such as using Firm Transmission Rights (FTR) to allocate scarce transmission capacity, centralized regional grid planning and better outage coordination. It does not discuss possible positive or negative impacts of the RTO on the development of innovative transmission and ancillary service products and markets, or changes to market power and its impacts.

Quantifiable benefits and costs –

- **Regulating Reserves Savings--**
  The RTO West structure, which includes one overall control area encompassing all of the pooled transmission facilities and the resources interconnected to them, will result in regulating reserve savings of 364 MW or $28 million annually based upon BPA tariff rates for these products. These savings come from two areas: taking advantage of the load diversity in the broader geographic scope of the RTO (295 MW savings) and taking advantage of recent North American Electric Reliability Council (NERC) standards for a relaxation of regulation requirements (69MW).

- **Effects of elimination of pancaked rates –**
  The Team has expended significant effort in attempting to model the effects that removal of pancaked rates within the RTO region would have on the market prices of electricity within the WSCC. We have attempted to simulate the pricing decisions made including the company rates and the transmission transfer payments between RTO parties. To date, we have determined that:
    - Removal of the friction between the companies' transmission systems tends to lower market pricing in areas of current high prices and tends to raise them in areas of relatively lower prices. This will have differential impacts on loads, integrated utilities and independent power producers.
    - Due to more efficient dispatch, there is a modest fuel savings (on the order of $30 million annually) in the Western Systems Coordinating Council (WSCC) area as a result of implementing the RTO.
    - Generators that are currently available for service should be dispatched more efficiently, thereby delaying future generation expansion.
    - The AURORA model assumes that the only impact on efficiency and competitiveness results from eliminating rate pancaking. The same level of trading liquidity and price discovery with and without an RTO.
    - The removal of pancaked rates would promote a more efficient generation expansion program and more efficient dispatch of generation.

Because of the modifications we have made to the AURORA model, the study results have produced significantly different results for small changes in input assumptions. We cannot, at this time, produce reliable conclusions as a result of this modeling effort. We believe, however, that the likely shifts in power prices are of sufficient importance to market participants to warrant continued examination.

- **Reduced exposure to large-scale grid outages --**
  The RTO is expected to reduce exposure to large-scale grid outages. That is estimated to provide benefits in the range of $33 to $328, provided the transition to the new RTO structure is successfully implemented. RTO West will have greater visibility of the grid it will manage than any of the participating utilities do today.

  The western interconnection operates as a single electric system. Often events far removed from one system affect another. Consolidation of information about the transmission system elements and interconnected resources should facilitate operating the grid more reliably. Reduction in the frequency of large scale, cascading events should result and restoration of service following outages should happen more quickly. Authority for ensuring that certain investments are made (backstop for reliability planning) has service to load reliability benefits.

  Mechanisms to utilize redispatch to relieve transmission overload conditions may have a reliability benefit over the current practice of schedule curtailment.

- **Implementation Costs –**
  The Implementation Team estimates the annual costs of a regional RTO, assuming 501(c)3 tax-exempt status, to be about $63 million, which includes $13 million for amortization of start-up costs of the $82 million initial cost, if the levelized cost of capital is 15 percent. These costs include computer systems, communications, support contracts, facilities, and staffing at a level of 277. If the start-up costs exceed this initial estimate by 100 percent, the annual cost of implementing RTO West would increase to $76 million. Reserves for capital or operating contingencies could raise the revenue requirement of RTO West to a total of $89 million. (See table on page 8.)

Implementation Costs
(Millions of U.S. Dollars per Year)

Item	Initial	O&M	O&M Amort. X 2
Computer/Comm.	$51	$ 7	$ 7
Facilities (brownfield)	$ 5	$ 2	$ 2
Staffing (277)	$20	$38	$38
Support contracts	$ 6	$ 5	$ 5
Cost of capital		$13	$26
Total	**$82**	**$63**	**$76**

Total Quantified Benefits and Costs --
The total benefit/costs, quantified at this time, of forming RTO West, which includes the costs and benefits to loads, generators, regulating reserves and implementation costs is shown in the table below.

Total Quantified Benefits and Costs
(Millions of U.S. Dollars per Year)

	RTO Overall	ETOs
Net Benefits/Costs to Loads	$TBD *	$TBD *
Regulating reserves savings	$28	$28
Reliability Benefits	$33-$328	$33–$328
RTO annual costs	($63--76)	($63-76)

* Net Benefits/Costs to Loads to be determined by AURORA analysis.

Qualitative benefits and costs --
This report also identifies a number of benefits and costs that the Team was not able to quantify. Among those are:

- An RTO would facilitate more appropriate market signals to encourage optimum economic use of scarce transmission capacity, increase trading, improve congestion management and guide regional investments in generation and transmission.

- Savings and efficiencies will be realized from consolidating control areas, through shopping at one OASIS for reservations and purchases of RTO transmission services, as well as from the existence of a single tariff and a single set of uniform business practices. In addition, capital costs will be avoided by consolidating the transmission scheduling and control systems. The cost of some lower voltage facilities may be collected through separate Executing Transmission Owner (ETO) Federal Energy Regulatory Commission (FERC) tariffs.

- Benefits will result from changes in the way the RTO will manage transmission congestion in real time. Operationally, relieving transmission overloads by redispatch as opposed to schedule curtailment (as is currently done) will provide improved grid reliability and cause less market disruption in real time. The costs for this management have been estimated in the Implementation Team's RTO West annual cost.

- Both FERC and the U.S. Department of Energy identified benefits of new products being developed as a result of a functioning market. DOE, in a May 25, 1999 document, said: "...(I)ncreased competition will call forth a wide range of innovative products and services that will add value and better meet customer needs." Most of these products are generation supply products attributable to deregulation, but there likely will be some transmission products emerging from the RTO and the RTO may foster new supply.

- The central planning and siting benefits of RTO West should result from a single utility perspective to identify least cost solutions without regard to ETO system boundaries and are expected to raise productivity through more efficient uses of staffing resources.

- Reliability of the transmission system will improve through clear planning authority and greater visibility of the grid -- that is if the Northwest is able to avoid the errors that have occurred in California. Care will need to be exercised in the startup through full operation, as in any new organization, to avoid transitional decreases in reliability.

- Additional costs may be incurred to retain a scheduling coordinator for all transactions.

- There will be one additional FERC proceeding for customers to follow related to approval of the RTO tariff.

- The valuation of existing transmission assets placed into operational control of the RTO and capital charges associated with those assets may change as a result of organizational changes due to the formation of the RTO.

Quantification of these costs and benefits would change the result in the Cost/Benefit table displayed above.

Comparing previous studies

Previous estimates of the cost and benefits of an RTO and/or deregulation have been compiled by FERC, U.S. DOE and by the Independent Grid Operator (IndeGO) study Team. While these reports provided value to the workgroup in comparing methodology and, to a certain degree, the results, RTO West benefits and cost estimates have been developed relatively independently. That is due to the unique geographic scope and policy decisions parties to RTO West have agreed upon.

Almost all of the estimated benefits evaluated by FERC in support of Order 2000 are based on more competition and entry of new generation suppliers into the market place. By 2010, national generation costs fall by 5 percent, which FERC equates roughly to a value of $2.4 billion.

A DOE study of the Comprehensive Electricity Competition Act estimated benefits from deregulation, including retail access as envisioned by the Act, could be as much $20 -- $32 billion in national annual cost savings. Cost savings in the Northwest Power Pool area, which is approximately one-half of RTO West, was estimated at $42 million annually.[1]

A third study was completed by the IndeGO study Team. That cost/benefit analysis considered a different type of RTO structure and geography than is being considered here. In March 1998, it estimated the costs to be $89 – $164 million in capital costs and $45 million in annual costs. The benefits related to elimination of pancakes and generation capacity expansion benefits were estimated to be approximately $100 million per year. It did not estimate regulating reserve savings or reliability benefits. The IndeGO geographic scope included greater reach in the Rocky Mountains, but did not include Canadian entities [for more information, see “Estimated benefit from the IndeGO Benefit Analysis”]. This study result was preliminary only and not reviewed to any significant extent in the region.

What this report does and what it does not do

- The report identifies areas in which benefits or costs from forming RTO West might develop.

- For a period of approximately ten years, load-based company rates and FTRs for existing contracts are proposed in an effort to keep cost shifting to a minimum.

- The RTO Benefits and Costs Team used the RTO West design agreed to by the Regional Representatives Group on September 20, 2000 as its basis.

[1] see “Estimated benefit of the Comprehensive Electricity Competition Act”.

- The estimated cost of RTO West operations does not include new costs for parties to interact with the RTO and to purchase RTO services. Likewise, the estimated benefits do not include savings as a result of existing functions being transferred from the ETOs to the RTO.

- The people whose ideas contributed to this summary have differing views about the likelihood and magnitude of the potential benefits and costs it describes.

The RTO West Benefits Team was made up of:
Robin MacLaren—PacifiCorp
Kevin O'Meara—Public Power Council
Lon Peters—Public Generating Pool
Vickie VanZandt—BPA Transmission Business Line
Don Matheson—BPA Transmission Business Line
Phil Carver—Oregon Office of Energy
Geoff Carr—Northwest Requirements Utilities
Linc Wolverton—Industrial Customers of Northwest Utilities
Ray Bliven—Direct Service Industries
Coe Hutchison—Snohomish PUD
John Leland—Montana Power Company
Dennis Phillips—BPA Power Business Line
Jim Henry – PacifiCorp

Transmission Planning and Siting Benefits and Costs

Today's world is changing
The main grid was developed by a handful of vertically integrated utilities in a spirit of cooperation and coordination. Transmission planners recognized reliability benefits from being interconnected with a large grid. Utilities were willing to accept relatively minor adverse consequences such as parallel path flows in order to achieve the significant reliability benefits of interconnection. As the electric power industry restructures, the number and composition of market participants are increasing and changing, and the motivation and benefits of being interconnected are changing. In the future, some participants may not have sufficient incentives to accommodate unavoidable adverse consequences, such as parallel path flow.

As the composition and number of market participants changes and increases as a result of deregulation, the spirit of cooperation and coordination that existed among the planners in the regulated world is being replaced by competition and confidentiality. The players no longer share common goals.

Having RTO West responsible for transmission planning for the regional grid should provide a more transparent and effective planning process than the coordinated, yet fragmented, planning process it will replace. Whether the total costs of central transmission planning and siting will increase or decline is hard to forecast and may even be hard to determine after the fact.

How RTO West Will Plan the Main Grid
Main grid planning will be continued in the future under the RTO's planning authority. RTO West will be responsible for planning for the RTO Grid using a non-discriminatory process, with significant input from all users of the system. The details of the process will be developed after the formation of the RTO but is expected to result in single-utility, least cost planning without regard to ETO boundaries.[2]
After alternatives have been developed through the RTO planning process, the ETOs have the primary decision-making authority regarding what facilities will be constructed to ensure the transmission adequacy of the RTO Grid ("keeping the lights on"). In the event that the ETOs fail to maintain such transmission adequacy, the RTO has backstop authority to require construction of necessary facilities. Decisions for expansion of the RTO Grid for economic reasons are left to those bearing the cost of the decision (such as the users who are impacted by congestion clearing charges). The RTO is expected to establish a process that will determine the benefits of replacement, reinforcement, and expansion

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[2] For more information regarding the Regional Representatives Group's decision on planning, please see "RTO West, August 25, 2000, RRG Decision Regarding Planning and Expansion."

decisions for reliability and allocate their costs to the ETO whose load has benefited.

RTO West's planning responsibility will include:

- Determining the capability of the RTO Grid.
- Identifying paths that are experiencing congestion and the current/historical specifics (price, duration, etc.).
- Assessing the transmission adequacy of the RTO Grid.
- Developing and enforcing interconnection standards.
- Providing the information developed above to the market.
- Coordinating expansion activities.
- Backstop assurance for investment in reliability if ETOs do not build.

ETOs planning responsibilities will include:

- The RTO West planning staff will analyze new ETO local facilities for impacts on the transfer capability of the RTO Grid and ensure that the project sponsor has appropriately mitigated negative impacts.
- Conversely, if the new ETO local facilities have created transfer capability on the RTO Grid, the ETO will be given any corresponding FTR.

Potential benefits include:

- Single focus - independence from non-transmission interests.
- Consistency in the assessment of capacity, adequacy and security of the regional grid.
- Reduced probability of region-wide outages over current practices.
- Clear authority for main grid planning is intended to ensure integrity of the regional grid over time.
- Provision of a new method to clearly identify paths experiencing congestion (flow paths).
- Development and enforcement of consistent interconnection standards.
- One-stop information source for market participants and project sponsors.
- One utility planning to identify least-cost solutions without regard to ETO system boundaries.
- Increased reliability due to backstop responsibility that assures investments for reliability are made.
- Central authority for distributing transmission costs over RTO-sponsored transmission facilities.

Potential costs include:

- The authority to direct expansion solutions without financial responsibility could lead to overbuilding of transmission assets.
- The risk of an intrusive bureaucracy could result in an over-regulated market.

Coordination of Planned Outages Benefits and Costs

Transmission Outage Coordination:
RTO West will have approval authority over planned maintenance outage scheduling. While the transmission asset owners are responsible for the maintenance and care of the facilities, integrated utilities may tend to schedule facility outages when that timing meets the specific interests of the utility. The RTO will attempt to coordinate outages so needed maintenance can be accomplished when the resulting reduction in transmission capacity will least impact the market as a whole.

Steps have been taken in the Northwest, through the efforts of the 45-day Northwest Power Pool outage coordination process, to limit the impact such outages would have on the marketplace. The RTO will make further improvements in making sure outages are taken when they have the least impact on power markets, rather than the least impact on the individual utility. The proposal includes extending major outage planning to 12 months to provide the best possible information for the annual FTR auction.

Potential benefits include:

- Reduced chances for market manipulation and improvements in competition.
- Greater availability of transmission inventory in periods of high market value for Available Transmission Capacity (ATC). As a result of more transparent information, the RTO should be able to coordinate scheduling outages to minimize impacts on commercial transactions better than utility organizations do today.
- When approved maintenance activities reduce available transmission capacity on a path, the RTO will facilitate coincident scheduling of other ETOs' needed maintenance when minimal or no additional reduction would result.

Potential costs include:

- ETO transmission assets may be stressed beyond their normal operating capability if normal maintenance requests are denied.
- Risk of Class B assets being stressed by virtue of planned outages on Class A facilities being changed.

Congestion Management Benefits and Costs

The Problem
Available Transmission Capacity (ATC) is currently posted by a variety of ETOs. When ATC is sold out, additional requests for capacity are not accepted unless the requesting party agrees to fund interconnection studies and pay for created capacity. They can do this through either tariffed rates for transmission or the costs associated with the upgrade as defined by the FERC 'or' test.

In addition, on transmission paths such as West of Hatwai, no ATC is available, yet this path is fully loaded less than 25 percent of the year. Parties wishing to use these paths may do so on a non-firm basis, but they cannot reliably or quickly buy firm rights to ensure firm energy or capacity sales, given the need for studies and upgrades.

To a limited degree, contract holders re-market unneeded capacity. The current system allows rights holders (transmission owners and their power marketing affiliates and load serving entities) to hold capacity that they may not intend to use until the pre-schedule day, forcing non-rights holders into the short term market. It is noted that eligible customers have the option of making a Section 211 request for firm transmission service.

However, through annual, monthly and daily FTR auctions, all available FTRs are brought to market. A robust secondary market is also facilitated through electronic exchanges and bilateral deals. In addition, FTRs not used in the day-ahead preschedule process are auctioned as Recallable Transmission Rights (RTR).

There is currently no comprehensive congestion management method that includes redispatching resources or loads through an open and fully competitive market to ensure reliability through transmission overload relief. When limits on a path are exceeded due to forced outages or other changes in system conditions (i.e., change in generation or load pattern), the tools currently available for NW system operators, short of load reduction, are generally limited to schedule cuts on commercial paths.

However, schedule curtailments are imprecise, sometimes ineffective (cut schedules can be replaced with other schedules utilizing the same path), often require a larger reduction than is necessary because it is imprecise, and can significantly disrupt energy markets. In addition, curtailments on commercial paths (which may not be overloaded) is one of the few tools available to relieve internal network constraints. There is no broad availability of open-access tariff provisions to recover redispatch costs.

The RTO West proposal for flow-based physical rights on flowpaths more closely aligns the commercial rights and arrangements for transmission with the operation of the system.

This mechanism identifies the transmission constraints that exist on the Northwest transmission network, and gives the RTO tools to precisely manage overloads on flowpaths or within a congestion zone. Tools include buying back FTRs, arranging for redispatch and pro rata curtailment. This method allows a specific set of actions that may solve the problem with greater precision. It can be accomplished more quickly (reliability benefit) and with less disruption to the energy market.

Managing Paths as a whole (even with multiple owners)
Currently, arrangements are made for transmission service separately among the various owners or rights holders of a path. Some owners may elect to sell their capacity differently than others. For example, some may offer all ATC on a firm basis; others part firm or part non-firm. Under some circumstances, when reductions are necessary, non-firm customers of one capacity owner may remain on the path, while firm customers of another capacity owner are cut.

In addition, sometimes transmission constraints are not relieved because of multiple ownership. Some owners may have no interest in relieving a specific path or may gain from its congestion. .As such, they may not wish to invest in solutions.

RTO West will manage the commercial arrangements for transmission paths that have multiple owners (i.e., the Northwest portion of the California-Oregon Intertie), as a whole leading to more consistent business practices.

The RTO Congestion Management Model
Correct economic signals to the market place through congestion pricing could facilitate stronger price signals for dispatch of energy and capacity resources, as well as demand side management. In addition, it could facilitate more appropriate market signals for guiding investment in these areas. Information about generation location that would relieve congestion is not readily available and incentives are not in place to help generators make siting decisions that could help relieve congestion. Transmission users, especially retail loads, are not provided with price information necessary to help relieve congested paths.

RTO West proposes a congestion management approach that will define and identify flowpaths as areas of significant congestion. Flow distribution factors will be used to define incremental power flows over each flowpath. The time over which such calculations will be made is uncertain at this point, as are the economic implications of such calculations. FTRs will be defined by the RTO for each flowpath based on the transfer capability of the flowpath.

FTRs will be made available to eligible customers based on entitlements under pre-existing contracts and load service obligations (LSOs), including load growth. To the extent capacity exists beyond the need to serve pre-existing contracts and LSOs over these flowpaths, that capacity will be made available and auctions held to set the prices for transmission rights over these paths.

Current rights holders will be able sell their FTRs and receive auction revenues, as well as purchase other FTRs for paths over which they do not have FTRs. Parties who do not currently have rights would be able to bid in the auction for the rights they are willing to pay for. The costs of relieving congestion during congested hours would be clearer and parties would be able to decide whether the transactions they seek to make are financially viable.

During non-congested hours transmission capacity should be available at a zero (or close to zero) price plus losses after load-based access charges. Scheduling coordinators will probably be required to perform functions associated with congestion management for individual transmission customers. (For a more detailed description see “RTO WEST: Physical Rights Model for Transmission Access and Congestion Management.”)

Under this new model, there are costs, cost shifts and benefits faced by all users of flowpaths.

Potential benefits include:

- Reduced chances for market manipulation and improvements in competition.
- Transmission overload mitigation should occur more quickly and with very little disruption to the market in real time. Redispatch solutions should be more precisely effective than schedule curtailment.
- More options will be available in addition to schedule curtailment. Thus, it is possible that less valued transactions will not replace more highly valued transactions.
- RTO West will manage the commercial arrangements among multiple owners for transmission paths, leading to more consistent business practices.
- Enhanced ability for non-FTR owners to obtain firm transmission rights to move power from the non-firm market to the firm market where it has greater value to customers.
- Allocation of scarce capacity on the basis of economic value so that fewer economic transactions are blocked (both power and transmission), therefore overall system operating costs are lowered

Potential costs include:

- Set-up and repeated implementation of FTR/RTR auctions.
- Possibility for market power to be created by improperly designed FTR auctions.
- Transactions costs of using a schedule coordinator (SC) or performing SC functions in house.

- Costs, including management of uncertainty, of participating in the FTR auction.
- Transaction costs (hardware, software, personnel) of establishing a system to physically track the usage of defined flowpaths.
- The potential costs of facing FTR auction prices at the end of the contract term.
- BPA will provide schedule coordination services at cost to its full requirements and simple partial requirements customers. If “at cost” is interpreted to mean that customers will face market prices for ancillary services, such as load following, then costs to some customers may increase compared to current practice.

Potential cost shifts from one transmission system user to another include:

- Internal congestion that the RTO pays to relieve will be paid through the uplift charge and socialized.
- Recovery of re-dispatch costs from customers.
- If a transmission path is not congested, through wheeling will not pay for operations and maintenance of that facility. Instead, costs of operation and maintenance will be borne entirely by payers of the Company Rate associated with that facility. However, reciprocity is assumed from neighboring RTOs. Through wheeling on their systems for transactions on behalf of RTO West loads will not pay for operations and maintenance of those neighboring facilities.

Costs/concerns that may arise if congestion management mechanisms are not properly constructed:

- Potential for the congestion management mechanism to create market power.
- It is not clear how the RTO is going to solve the generation siting problem in the near term because of the lack of transmission planners.

Ancillary Services Benefits and Costs

Markets will drive the costs and benefits
The benefits and costs of RTO formation in markets for ancillary services depend critically on the nature of those markets once the RTO begins operations. At this point, there is insufficient information available to accurately estimate all benefits and costs. The benefit due to reductions in regulation reserve requirements and the potential benefits in operating reserves were analyzed, while other ancillary services were not.

Given available information, it is premature to conclude that the RTO will either improve or degrade the position of consumers in the area of ancillary and interconnected operations services. Much depends on the incentives facing the RTO, and the resulting decisions in critical areas associated with both the acquisition of ancillary services or interconnected operation services and the ability to self-supply these services.

To judge this, we need to project or describe the delivered prices of ancillary services with and without an RTO in the future. Ideally, this would rely on information regarding the number of buyers and sellers, availability of information, and entry and exit conditions. Practically, much of this information is not available.

Regulation Benefits:
Currently, the 10 control areas operated by the ETOs, plus the British Columbia control area, carry 504 MW for regulation. The RTO West structure, which includes one overall NERC control area encompassing all of the ETOs' pooled transmission facilities and the resources interconnected to them, will result in regulating reserve savings of 364 MW.

Even if individual utilities wish to self-track and provide for their own load following – as some intend to do – regulation benefits will be achieved by taking advantage of the load diversity in the broader geographic scope of the RTO.

This requirement after the RTO forms its overall control area will drop from the current 504 MW to 209 MW, achieving savings entirely attributable to the RTO due to load diversity over a broader geographic area of 295 MW. In addition, employing the recent NERC standards, which allows for a relaxation of regulation requirements, will allow this overall requirement to be reduced an additional 69 MW to 140 MW in total. To achieve the additional savings associated with relaxed control (69 MW), the RTO will need to implement this at start up in its automatic generation control (AGC) system.

The following table includes the specific benefits for relaxation by company and added load diversity of a broader geographic scope distributed by percentage of total load.

AVA (WA)	19 MW	$1.5 million annually
IPC (ID)	22 MW	$1.7 M
MPC (MT)	13 MW	$1.0 M
PACE (UT/WY)	46 MW	$3.5 M
PACW (OR)	29 MW	$2.2 M
PACW (WA)	12 MW	$0.9 M
PGE (OR)	27 MW	$2.1 M
PSE (WA)	31 MW	$2.4 M
SPP (NV)	14 MW	$1.1 M
BCH (BC)	80 MW	$6.1 M
BPA (WA/OR)	71 MW	$5.5 M
Total	**364 MW**	**$28M**

Even the implementation of the new NERC standards were done by all 11 control areas, this would not result in similar savings without the formation of an RTO. Some savings would result (up to 186 MW), but not nearly what could be achieved with the consolidation to one overall control area (364 MW). If all 11 control areas would make the AGC system modifications to employ the new NERC criteria (at approximately eleven times the cost of implementing it once through the RTO), the regulating reserve requirement would drop to 336 MW (as opposed to 140 MW with a single control area). However, even though relaxed control has been approved by NERC for over two years, no control areas have made the system changes necessary to implement it.

Total Regulation Benefit:

- 364 MW reduction in Regulation Reserves Requirement.
- If priced at $6.40 per KW-month, savings = $28 million annually.

Operating Reserves

The potential for savings of operating reserves was analyzed. Northwest Control Area Contingency Reserves allocation is based on the WSCC percentage method. By utilizing a Reserve Sharing Group, the NW Control areas have reduced net reserve capacity by 3,665 MW. Further savings are not anticipated by the proposed RTO West.

Potential benefits include:

- Savings in regulating reserves are expected to be 364 MW and estimated to be valued at approximately $28 million annually. The predicted savings are available when RTO West's control area begins operating. The value of capacity savings was estimated based on $6.40 per kW-month.

- A single Northwest market for AS/IOS facilitated by the RTO may expand the size of that market, increase competition among potential suppliers of ancillary services, improve communications among market participants, and reduce transaction costs.
- Standardization of AS/IOS (as supplier of last resort) definitions across a wider geographical market may enhance competition.
- Separation of AS/IOS technical requirements from ownership of generation may enhance competition.
- If the process by which the RTO acquires AS/IOS is sufficiently competitive, the resulting prices may be lower than otherwise would result.

Potential costs include:

- The RTO's formal approach to establishing a market for AS/IOS may be more expensive to operate than an informal (bilateral) approach because of the lack of incentive to minimize the cost of operating such a market. Regulation by FERC would have to be used instead of competitive forces to keep down the costs of operation. If such regulation is not as effective as competitive forces, the result will be higher costs for consumers than are necessary.
- If the rules for self-supply of ancillary services are unreasonable or cumbersome, the self-supply option may be thwarted, thus reducing the potential for the benefits of competitive supply of such services.
- If the zones established by the RTO for Balancing Energy purchases do not contain a large enough number of potential suppliers, the resulting Balancing Energy costs will not be competitive. If the RTO does not have an interest in minimizing the costs of Balancing Energy because these costs are simply passed through to Scheduling Coordinators, then the result will be more expensive than necessary for end-users. It will not be sufficient to "deem" that competitive markets exist for AS or IOS. It is not clear yet that the RTO has the incentive to maximize competition among potential suppliers of AS/IOS.
- Currently BPA provides generation-related ancillary services to its customers at the cost of power from federal projects. If the rates for provision of these ancillary services move to a market basis due to locational or other considerations, this could impose significant additional costs on BPA's customers.

Power Markets Impacts Benefits and Costs

Focus Group
Audrey Perino—BPA Power Business Line
Dennis Phillips—BPA Power Business Line
Jeff King—Northwest Power Planning Council
Kurt Granat—PacifiCorp
LincWolverton—ICNU
Matt Staneff—Snohomish PUD
Ray Bliven—RCS for DSIs
Don Matheson—BPA Transmission Business Line
Rob Anderson—BPA Power Business Line
Robert Petty—BPA Power Business Line
Warren Winters—EPIS
Lee Barney—EPIS

Not only does RTO West affect transmission rates among the various participants, but elements of its design also affect power markets throughout the West. Cost shifts can occur between utilities, particularly as a result of changes in transfer payments. But, they also can occur between end-user loads and independent power producers (IPPs) and the generation (merchant) function of vertically integrated utilities.

The Benefits/Costs Team chose to model these effects with the AURORA model. The model is discussed more fully below, but, in summary, it calculates spot power prices in areas of the West, after taking into account the operating costs of thousands of generation resources, transmission constraints, and transmission rates and losses. It is one of the primary models used by utilities and other entities looking at prospects for West Coast marginal power prices. The model was used by BPA, for example, in its recent power rate case to project purchase power costs and short-term sales revenues for its 2002 to 2006 rate period, and by the Northwest Power Planning Council in analyzing regional resource adequacy.

The purpose of analyzing power markets through AURORA is threefold. First, AURORA can provide an estimate of the savings due to the different generation dispatch that results from elimination of pancaked transmission charges. Second, it can provide an estimate of the capacity cost savings due to elimination of the same charges. Finally, it can provide an estimate of the power-cost impacts of opening markets throughout the West—impacts both on the load and generation functions of the utilities. It analyzes these impacts simultaneously, so only the combined results are available.

Modeling results to date

The RTO Benefits and Cost Team has expended significant effort in attempting to model the effects that removal of pancaked rates within the RTO region would have on the market prices of electricity within the Western Systems Coordinating Council (WSCC). We have attempted to simulate the pricing decisions made including the company rates and the transmission transfer payments between RTO parties. To date, we have determined that:

- Removal of the friction between the companies' transmission systems tends to lower market pricing in areas of current high prices and tends to raise them in areas of relatively lower prices. This will have differential impacts on loads, integrated utilities and independent power producers.
- Due to more efficient dispatch, there is a modest fuel savings (on the order of $30 million annually) in the WSCC area as a result of implementing the RTO.
- Generators that are currently available for service should be dispatched more efficiently, thereby delaying future generation expansion.

Because of the modifications we have made to the AURORA model, the study results have produced significantly different results for small changes in input assumptions. We cannot, at this time, produce reliable conclusions as a result of this modeling effort.

We believe, however, that the likely shifts in power prices are of sufficient importance to market participants to warrant continued examination.

Detailed description of the AURORA Electric Market Model

AURORA applies economic principles and dispatch simulation techniques to model the relationships of supply, transportation and demand for electric energy. It provides:

- Electric price forecasts for:
  Geographic areas and trading hubs
  Hourly, daily, monthly and annual time periods
  On-peak, off-peak or other defined sets of hours
- Resource value forecasts for:
  All existing generating units
  Future generating unit alternatives
  Demand side resources
  Hourly, daily, monthly and annual time periods
- Resource strategy forecasts (capacity expansion):
  Uses net present value (NPV) of resource value
  Optimal resource strategies for long-term runs
- Portfolio analysis for:
  User defined sets of contracts and resources
  Monthly and annual time periods
- Uncertainty analysis for:

Price, value and defined portfolios
Input sampling of key fundamental drivers

- Transmission usage and congestion.

AURORA uses information about the fundamental economic drivers to make its forecast, which includes:

- Electricity demand by geographic area, annually and monthly, including hourly shapes.
- Supply side resources.
- Heat rates, fuel types, commitment data and other resource information.
- Future resource alternatives are key in long-term optimization runs.
- Demand side resources including an interruptible price curve.
- Fuel prices by fuel type and geographic logic.
- Hydro information for AURORA's hydro optimization logic.
- Transmission costs and constraints.
- For uncertainty analysis, statistical distributions for key input drivers such as demand, fuel prices and hydro conditions.

AURORA simulates the economic dispatch of resources to meet demand requirements. It solves the whole system dispatch simultaneously. AURORA determines the market clearing prices from marginal costs. With market prices, it values all of the resources in the system. These price and value forecasts are provided for each time period being studied. For long-term runs, AURORA has resource optimization logic, which uses the NPV of market value of resources to determine an optimal set of resources to use in the system. Resources with negative market value are retired and new resource alternatives which generate positive market values are added.

AURORA's features also include:

- Hydro optimization logic.
- Long-term optimization logic.
- Uncertainty Analysis.

Modifications made in AURORA to accommodate RTO West analyses

The Benefits/Costs Team modified the AURORA model in order to analyze the impact of the decisions made for RTO West. The following are the principal changes that were made:

- Company areas were defined and substituted for the AURORA market areas in order to facilitate analysis of the company rate proposal by the RRG. These company areas are based on the service territories of the ETOs.
- Transactions charges on generation sales were replaced by company rate transmission charges to loads, added after market prices had been determined.
- "Pancaked" transmission losses defined by existing company transmission tariffs were replaced by area and path losses adjusted to produce the same total losses as are experienced under current transmission tariffs today.

- Although the model allows for user-defined contractual arrangements between suppliers and loads, we did not utilize this feature.
- Reciprocity between neighboring systems was assumed (no charges for through wheeling for service to external loads).

Analysis Methodology

The methodology used to analyze RTO West is straightforward:

1) run the model with a set of conditions based upon current pancaked tariffs;
2) run the model under an approximation of the RTO West structure—that is, load-based company tariffs;
3) calculate the differences in the results in terms of payments by loads in each company, financial returns to generation in each company, and returns to non-company-owned independent power producers.

Reliability Impacts Benefits and Costs

Background – The Problem:
As deregulation continues, changing conditions have emerged that pose a threat to system reliability. The following table reflects some of these:

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

The RTO structure proposed should be able to preserve or enhance reliability because it is expected to balance the availability of transmission with the need to maintain transmission assets; weigh efficient, low cost service against the need to keep the system stable; can assure needed facilities and reinforcements are built for reliability; and would arrange outages that had the least impact on the market as a whole.

Transition:

It is noted that care would need to be taken in transition to assure system reliability. Risk is associated with a move to a new structure. As an example, California's early reliability performance after startup to the PX and ISO was poor compared to its previous structure.

The Western Interconnection:

Reliability vigilance is particularly critical:

- in regions characterized by long, high capacity lines;
- in systems where transfer capability is defined more by stability limits (voltage or angular) rather than thermal limits;
- and where automatic or operator control actions must be taken very quickly.

The western interconnection has these characteristics and RTO West, as a result, would have challenges that other parts of the US would experience to a lesser degree.

Lack of Recent Transmission Investments:

As evidenced by the absence of major transmission projects undertaken in the West in the past several years, utilities have, for economic and environmental reasons found ways to increase the utilization of their existing facilities to meet increasing demands without adding significant high voltage equipment. This trend will likely continue. Pushing the system harder will undoubtedly increase reliability challenges.

The system in the Northwest has seen a dramatic increase in the use of the transmission system that is attributable to both load growth and through put resulting from competition. The NW transmission system has seen greater than a 30% increase in system utilization over the past 5 years. There is very little margin left in the system, making the preservation of system reliability a harder job than it used to be. It is being operated closer to the edge of security than it was just a few years ago.

The Need for Sufficient Reactive Support:

Voltage collapse (largely the result of insufficient reactive supply) is a significant phenomenon that has been experienced worldwide in only a handful of incidents. Predictions that this problem will continue to grow are added to changes in the regulation and economics of the industry to provide a significant reliability challenge. Voltage collapse can cause cascading outages that can affect large numbers of customers. Ensuring the appropriate amount and location of ancillary products including reactive supply would be the responsibility of the RTO.

Visibility of the RTO West Grid:

RTO West would have real-time "visibility" of the grid. Visibility includes (1) time-synchronized voltage, real and reactive power and phase angle measurements;

and (2) status of grid and resource components--whether they are energized or not.

It would be important to “see” the transmission being scheduled and operated because:

- Real-time and next hour adjustments of a transmission flow-gate’s Available Transfer Capacity (ATC) will be based on simultaneous flows on interacting paths, outages, and security assessment--as well as commitments for use of the flow-gate.

- Transmission schedules need to be visible so that resource adjustments can be made in real-time to prevent and quickly mitigate disturbances.

- Mitigation of disturbances (both automatic and manual) is dependent on knowing the real-time status of the transmission system across the broadest possible geographic scope (whole RTO West grid).

History and Characteristics of Power System Outages:

Outages occur on power systems with short, localized impacts fairly frequently. System-wide disturbances that affect many customers across a broad geographic are rare, but they occur more frequently than a normal distribution of probabilities would predict. North American power system outages between 1984 and 1997 are shown below in Figures 1 and 2 by the number of customers affected and the rate of occurrence (John Doyle, California Institute of Technology, “Complexity and Robustness,” 1999). This graph shows a distribution that follows power laws with fat tails – meaning outages affecting very large numbers of customers occur more frequently than a standard bell-shaped curve would indicate. Electric power systems are fairly robust to withstanding one or two contingency events, but fragile with respect to multiple contingency events.

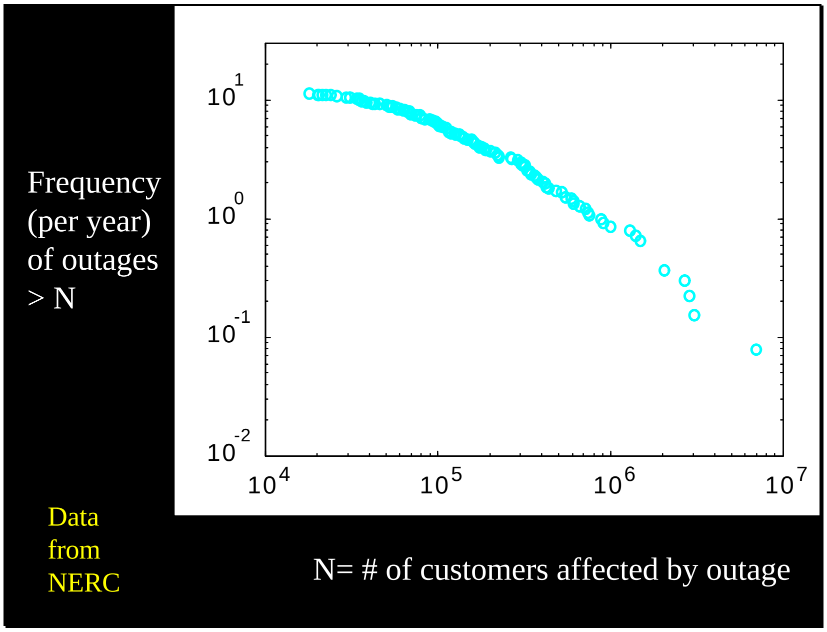

Figure 1

The bubbles represent individual outages in North America between 1984 and 1997

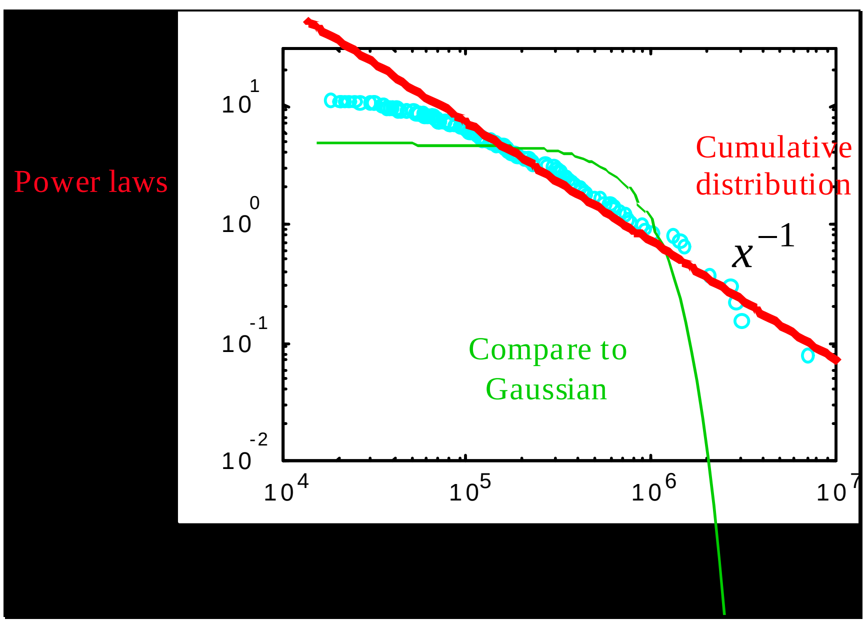

Figure 2

Power Law Distribution
versus
Normal Distribution

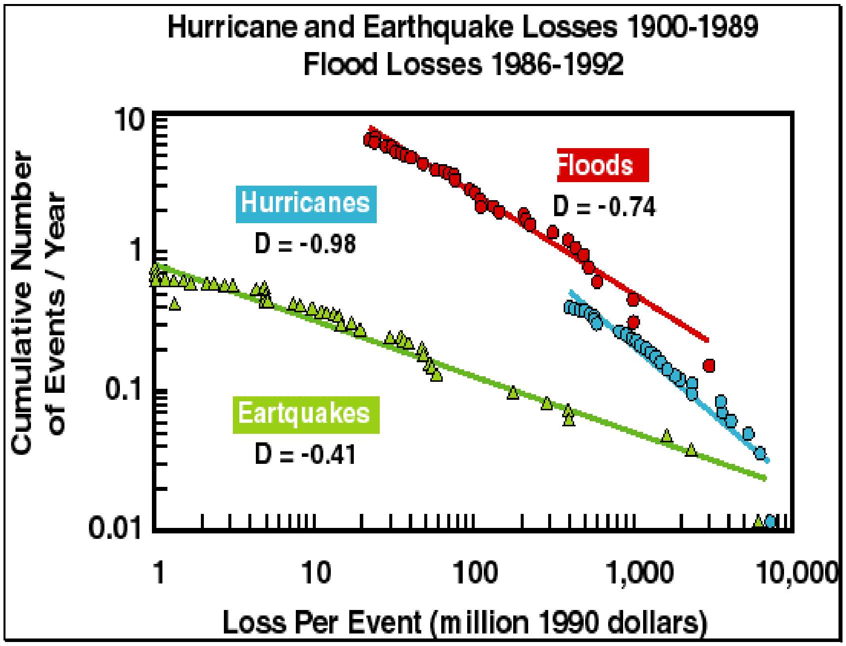

Figure 3

Some Types of Events Exhibiting Power Law Distribution

Figure 1 represents historical outage probabilities for the 13 years prior to 1998. With the lack of margin in the current transmission system, it is more vulnerable to cascading outages than it was in the past. If nothing else were to change, one could expect an increased frequency of large scale or fat tail events – or a flatter power law curve – than this historic one.

Reliability Benefit of the RTO Structure

Considering two alternative futures, one with broad scope RTOs and one without, the RTO structure will be less vulnerable to these large impact events. It is not assumed that the RTO would have significant impact on momentary outages over the no-RTO structure. It should have a positive impact on small scale events because of its backstop authority in making sure reliability investments are made. Its affect on preventing or reducing the duration of cascading or wide-spread outages, however, is expected to be significant because the RTO will:

- Have visibility of the whole grid
- Plan needed enhancements for main grid reliability – including stability controls
- Manage all flow paths in real-time
- Have better tools (redispatch vs schedule curtailments) to manage transmission overloads
- Ensure reliability investments are made
- Approve planned outages
- Manage system restoration following an outage, and have
- Greater accountability to the region for reliability criteria compliance

Historical outages with the largest impacts on customers (fat tail events) include a significant number of cascading events. As described above, RTO West should have a positive impact on preventing cascading outages, and in reducing the duration of outages if they do occur through management of system restoration activities (restoring service following a large, cascading outage generally takes significant time – hours to days).

If prevention of some of these events results in greater time between large scale outages (decreasing frequency), or if restoration is accomplished more quickly following a disturbance (decreasing duration), the costs of load loss would go down.

How Is This Reliability Impact Valued?

Current data on load lost in the RTO West region shows an average annual outage duration of approximately 78 minutes. This average includes momentary as well as extended unplanned outages.

The value of preventing outages or decreasing their duration was determined by the ranges identified in a summary of 16 studies of customer outage costs (Chi-Keung Woo and Roger L. Pupp, "Costs of Service Disruptions to Electricity Consumers," July 30, 1991). Because there is a wide range of values associated with the costs per kwH of unserved energy ($5 to $50 per unserved kwH), we provided the entire range of benefit.

If the NW region were to experience an average duration (78 minute) outage, the total cost to the loads of the RTO West filing utilities would be between $328 million and $3.3 billion using the study range.

It is noted that the customer outage cost data is approximately 10 years old and that commercial and industrial sensitivity to loss of load, in particular, may be changing. We have also assumed no load loss outside the NW region. For large scale outages, that may be a conservative assumption.

Assuming a decrease in frequency and duration of large scale outages as discussed above, if RTO West could prevent one 78 minute outage affecting the RTO West load once every 10 years, the annual value would be between $33 million and $328 million.

Potential Benefits Include:

- RTO West will have greater visibility of the grid it will manage than any of the participating utilities do today. The western interconnection operates as a single electric system. Often events far removed from one system effect another. Consolidation of information about the transmission system elements and interconnected resources should facilitate operating the grid more reliably. Reduction in the frequency of large scale, cascading events should result.

- Restoration of service following outages should happen more quickly.
- Authority for ensuring that certain investments are made (backstop for reliability planning) has service to load reliability benefits.
- Mechanisms to utilize redispatch to relieve transmission overload conditions may have a reliability benefit over current practices of schedule curtailment. When limits on a path are exceeded due to forced outages or other changes in system conditions (i.e., change in generation or load pattern), the tools currently available for NW system operators, short of load reduction, are generally limited to schedule cuts on commercial paths. However, schedule curtailments are imprecise, sometimes ineffective (cut schedules can be replaced with other schedules utilizing the same path), often require a larger reduction than is necessary because it is imprecise, and take more time to relieve the overload than redispatching generation from a market bid stack.

Reliability Benefits Range: $ 33 M - $ 328 M annually

Potential Costs Include:

- Costs to implement these benefits have been estimated in the Implementation Team's RTO West annual cost. Relevant features of RTO West implementation includes a single, grid-wide control area, main grid planning authority – including determination of grid-wide automatic stability control systems (remedial action schemes), planned outage approval, system restoration coordination responsibility, and backstop authority for ensuring reliability investments are made.