UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C.

Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000	Docket No. RT01-35

COMMENTS TO THE FERC ON THE STAGE 2 FILING OF RTO WEST

The Oregon Public Utility Commission (OPUC) and the Oregon Office of Energy (OOE), (jointly, "Oregon") appreciate the opportunity to comment to the Commission on the RTO West "Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000" by Avista Corporation, Bonneville Power Administration, Idaho Power company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Power company (Filing Utilities), pursuant to Order No. 2000.

Oregon supports the creation of RTOs under the proper circumstances. At this time, however, Oregon can neither support nor oppose the formation of RTO West. Under state law, the OPUC will take an official position when it decides to approve or reject the transfer of control of the transmission facilities of Portland General Electric and PacifiCorp over to RTO West based on a finding of public benefit.

Oregon supports the request by RTO West for a declaratory order, but that support is conditioned on acceptance of several changes that we recommend. We believe that the filing satisfies the requirements of Order 2000. We understand that the filing utilities will submit additional filings that will provide additional information now lacking on such critical issues as ancillary services, treatment of losses, seams with other regions, and market monitoring and mitigation.

RECOMMENDATIONS

Oregon offers the following recommendations on the RTO West Stage 2 filing:

- **The Commission should accept the design features in the filing that are structured to accommodate the characteristics of the Northwest markets, to minimize cost shifts, and to protect existing contract rights;**
- **The Commission should require RTO West to facilitate the development of day-ahead and hour-ahead energy markets;**
- **The Commission should require that the RTO West's backstop expansion authority include the ability to implement any least-cost alternatives;**

- **The Commission should specify that the protection for interconnected loads does not include protection from price competition;**
- **The Commission should reject the proposal that States direct the termination of loads whose scheduling coordinators have defaulted;**
- **The Commission should require that state regulatory agencies automatically receive Party status in arbitrations related to rates paid by retail loads under their jurisdiction.**

A detailed discussion of these recommendations follows below.

DISCUSSION OF RECOMMENDATIONS

The Commission should accept the design features in the filing that are structured to accommodate the characteristics of the Northwest markets, to minimize cost shifts, and to protect existing contract rights

Many diverse parties representing many interests have spent much of the last eighteen months carefully crafting a proposal that balances parties' interests and satisfies the Commissions objectives as listed in Order 2000. Oregon believes that the current filing strikes a good balance between the various interests and meets the Commission's goals.

Oregon previously filed comments on "Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design" (Working Paper). In those comments, Oregon recommended alternatives to various design elements proposed by the Commission. Our comments were written with an eye to those design elements included in RTO West's Stage 2 filing that we support and which differ from those proposed by the Commission. Following is a list of the RTO West proposed design elements that we recommend the Commission adopt:

- Voluntary bid-based congestion pricing and unit commitment;
- Voluntary conversion of existing rights and contracts;
- Transmission rights may be defined as options not obligations;
- Transmission rights may be defined as source-to-sink, not flowgate rights;
- Participants may be required to submit balanced schedules; and
- Participants only receive congestion credits against congestion costs incurred by a proposed schedule.

For a detailed discussion please see our comments filed with the Commission regarding the Working Paper (attached).

The Commission should require RTO West to facilitate the development of day-ahead and hour-ahead energy markets

The existence of hour-ahead and day-ahead energy markets is essential for development of an efficient wholesale electricity market. Oregon believes that day-ahead and hour-ahead energy markets will improve price transparency and market liquidity. Price transparency will help regulatory agencies monitor markets for market abuses, and will make it easier for market participants to make economically correct resource use decisions. Day-ahead and hour-ahead markets will improve market liquidity since market participants will be able to reverse longer term, bilateral contracts in the day-ahead and hour-ahead markets, rather than relying on the real-time or ancillary services markets.

The Commission should require RTO West to facilitate the development of day-ahead and hour-ahead energy markets. The day-ahead and hour-ahead energy markets should operate under the same set of rules that apply to the real-time and ancillary services markets. Oregon has not, as yet, developed a position on whether it is preferable for RTO West to operate the energy markets or to assume an advisory role with the energy markets operated independently. However, as currently written RTO West's By-laws (Article III, page 9) and the transmission operating agreement (TOA) (Attachment A, page 114) prohibit the RTO from operating or having any financial interest in a power exchange. If RTO West were required to operate day-ahead and hour ahead markets the Bylaws and TOA would need to be modified. This change would be consistent with the Commission's March 15, 2002 Standard Market Design paper.

The Commission should require that the RTO West backstop expansion authority include the ability to implement any least-cost alternatives

The Stage 2 filing allows RTO West to implement transmission expansions (backstops) and to allocate costs to remedy four circumstances:
1. Violation of Transmission Adequacy Standards;
2. Failure by the transmission owner to provide sufficient Congestion Management Assets to provide for its Catalogue of Transmission Rights;
3. Failure by the transmission owner to restore its Total Transmission Capability; and
4. Chronic, significant commercial congestion as the result of market failure (see Attachment I, pp. 6-10).

Only in the case of a violation of Transmission Adequacy Standards would the proposal allow RTO West to use least-cost non-transmission alternatives. In the other three cases, RTO West could suggest least cost alternatives, but if the transmission owner refused, RTO West could only expand or upgrade transmission facilities. Oregon recommends that RTO West have authority to implement least-cost alternatives for all four of its backstops. Oregon believes that RTO West needs to have the ability to implement least-cost investments to ensure a reliable and efficient transmission system.

All four circumstances could result in costs being allocated to the loads of investor-owned utilities regulated by the OPUC. As currently proposed, RTO West's Stage 2 filing does not include a specific role for state commissions. Oregon recommends that the Commission direct the Filing Utilities to work with state commissions to develop a proposal for an interstate panel with significant state regulatory participation to review RTO West backstop and allocation proposals prior to review by the Commission. Oregon has had preliminary discussions with some of the Filing Utilities about possible roles for such a panel.

The Commission should specify that the protection for interconnected loads does not include protection from price competition

The Transmission Operating Agreement (pp. 12-13, Sec 5.1 Adoption and Application of Interconnection Standards) contains the following provisions:

> *RTO West may adopt interconnection standards applicable to the Electric System of the Executing Transmission Owner that supersede in whole or in part the interconnection standards of the Executing Transmission Owner, provided such standards (1) are consistent with applicable regulatory requirements and industry standards and (2)* ***do not have a material adverse impact on the*** *Executing Transmission Owner's Electric System or* ***Interonnected Loads (including financial impacts).*** (emphasis added)

As written, this standard suggests that transmission owners would have protection from competitive generators. For example, if allowing access by competing generators lowered the market price, the regulated generation of the Executing Transmission Owner (ETO) might earn less net revenue. Since these funds flow to loads (after regulatory lag), this would have a negative financial impact on the Interconnected Loads. The Commission should specify that adverse financial impacts to Interconnected Loads of the Executing Transmission Owner do not include impacts on the market price of power from the interconnection of competing generators.

The Commission should reject the proposal that States direct the termination of loads whose scheduling coordinators have defaulted.

The Transmission Operating Agreement (Sec. 6.11, p. 33, Scheduling Coordinator Default) contains the following provisions:

> *Before the Transmission Service Commencement Date,* ***RTO West shall use its best efforts to obtain the assurance*** *of each State or tribal authority within RTO West boundaries that if a default by a Scheduling Coordinator occurs and the affected Transmission Customers are unable to secure a replacement Scheduling Coordinator within ____ (__) days of such default after making a good-faith effort to do so****, the State or tribal authority will direct the termination of service to load(s) for which such defaulting Scheduling Coordinator serves*** *as Scheduling Coordinator until a replacement Scheduling Coordinator is secured. RTO West also shall use its best efforts to develop and maintain other cost-effective means of protecting Transmission Customers from any material adverse financial impacts resulting from the effect on RTO West of the default of any other Transmission Customer or its Scheduling Coordinator.* (emphasis added)

Oregon believes that termination of loads by state or tribal authority in not physically possible. In addition, it is not the correct remedy for Scheduling Coordinator default. Instead the Commission should instruct RTO West to file a tariff that would allow RTO West to immediately begin collecting any defaulted costs (subject to refund) from the loads of customers of the SC who defaulted. It would be unfair to collect these costs from any other party. Any delay in collecting the defaulted cost would impose an untenable burden on RTO West and its customers.

The Commission should require that state regulatory agencies automatically receive Party status in arbitrations related to rates paid by retail loads under their jurisdiction.

State regulatory commissions are apparently denied "Party" status under the proposed RTO West arbitration rules (Bylaws, p. C-6, Sec. C1.3.5.4). Instead, state commissions are relegated to "Participant" status, with less procedural rights. For example, Participants may only appeal an arbitrator's findings to the Commission "with respect to issues on which the Participant was allowed to present evidence pursuant to Section C1.3.5.6." (Bylaws, p. C-11, Sec. C1.5.1).

State commissions currently assure that retail rates to recover transmission costs are just and reasonable. Under RTO West, the decision makers will be the independent board, arbitrators and the Commission. It is the responsibility of the OPUC to protect retail customers under its jurisdiction. It is unreasonable to deny state commissions full Party status before RTO West arbitrators and to restrict the state commissions' ability to appeal arbitrators' findings to the Commission.

DATED this 29th day of May 2002.

Respectfully submitted,

/s/	/s/	/s/
Roy Hemmingway	Joan Smith	Lee Beyer
Chairman, OPUC	Commissioner, OPUC	Commissioner, OPUC

/s/
Michael Grainey
Director, Oregon Office of Energy

Attachment: Oregon Comments on Working Paper, filed on April 10, 2002

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C.

Electricity Market Design and Structure
Notice of Working Paper
Docket No. RM01-12-000

COMMENTS ON WORKING PAPER ON STANDARDIZED TRANSMISSION SERVICE AND WHOLESALE ELECTRIC MARKET DESIGN

The Oregon Public Utility Commission (OPUC) and the Oregon Office of Energy (OOE), (jointly, "Oregon") appreciate the opportunity to comment on the "Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design" (Working Paper).

Oregon has three overarching comments and recommendations on the paper.

1. The Commission's paper sets forth appropriate goals and principles for the ultimate design and operation of wholesale electricity markets.

2. The Commission's draft and final rule should explicitly recognize alternative design elements that reflect regional differences in wholesale markets, but still meet the Commission's goals.

3. Before issuing a NOPR, the Commission should issue a revised Working Paper that provides substantially more detail on its proposed policies on market power mitigation, long-term generation adequacy, and transition issues, among other design issues.

Below we offer more detailed comments on specific design elements.

Locational marginal prices should be bid-based, not cost-based.

Oregon strongly supports the Commission's proposal of bid-based determination of locational marginal prices. In competitive markets the clearing price is set by balancing the incremental offer to sell and the incremental offer to buy a given commodity or service. The wholesale energy market should be designed to achieve the same end, except for those circumstances in which the potential for significant market abuse exists.

Bid-based LMP also better fits the wholesale marketplace in the Northwest. The Northwest states rely heavily on hydroelectric generation. Requiring hydroelectric facilities to bid marginal hourly costs could result in the output from these resources

1. being undervalued. That would alter the dispatch of resources producing electricity in the

Northwest and increase the total cost of producing electricity in the Northwest.

The Commission should require that the RTO administer an hour-ahead and a day-ahead energy market.

We recommend that the Commission require that RTOs administer an hour-ahead market in addition to the day-ahead market. That requirement would improve both market liquidity and price transparency. With an hour-ahead market, market participants would be able to reverse longer-term positions in both the hour-ahead, as well as the real-time market. Having a viable hour-ahead market also would improve wholesale price transparency, as compared to the alternative of a bilateral market, since it would result in published hour-ahead prices by node or location.

RTOs should require that market participants submit balanced schedules.

We believe that the load serving entities (LSEs), not the RTO, are responsible for long-term reliability of their system. With that responsibility comes the duty to provide the resources necessary to meet their load, as the Commission recognizes.[1] We believe that this responsibility effectively requires balanced schedules.

The Commission should specify what policies it will initiate to ensure that the direct costs of an RTO are not excessive.

The central issue for regulatory agencies is whether the costs of an RTO will exceed the benefits. Because states have no regulatory oversight over the RTO, a concern is that costs of administering an RTO will be unchecked. The Commission should detail what policies it proposes to control the costs of an RTO.

Full reqirement customers of utilities should not be allowed to bid demand reduction into the wholesale markets.

Oregon recognizes that demand response is an important and valuable component in a viable wholesale energy market. We support the development of a wholesale demand-side market in which utilities and direct-access customers can bid in cost-effective load reductions. However, for the same reasons offered by NARUC and other commissions, full-requirement customers of utilities should not be allowed to participate in this market.

Transmission rights should be initially defined as source-to-sink rights, and RTOs should not be required to offer flowgate transmission rights.

[1] "When load must be curtailed due to insufficient generation, the transmission provider should avoid curtailing LSEs that have procured sufficient generation, if operationally possible." Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, page 24.

We believe that requiring both source-to-sink and flowgate rights (once participants request flowgate rights) is unnecessary and would unduly complicate the market for transmission rights. Having two types of transmission rights may also reduce the liquidity of the market since this would create two smaller transmission rights markets.

We believe that source-to-sink rights are simpler to use than flowgate rights and better reflect the cost of congestion. With source-to-sink rights, transmission customers need only buy one set of rights to be fully hedged between two points. With flowgate rights, transmission customers would need to buy rights on all paths with flows between the points in order to fully hedge their transmission costs.

Transmission rights should be defined as options, not obligations.

Oregon believes that transmission rights are more properly defined as options rather than obligations. Our concern is that defining rights as obligations will reduce participants' incentive to buy long-term rights and, as a result, more transactions will occur in volatile, short term markets. When transmission rights are defined as obligations, the value of transmission rights could become negative, whereas with an option the value can never go below zero. As a result, when defined as obligations, the number of transmission rights purchased and the market price for those rights will be lower than if they had been defined as options.

Transmission rights holders should not receive congestion credits for rights they did not schedule.

If a rights holder does not need to schedule use of its rights to receive congestion revenue, then a rights holder would likely only sell its rights if the expected sale price were greater than the expected congestion revenue. In fact, the sales price would probably need to be considerably higher than the expected congestion revenue, since holding onto the rights reduces the risk that the rights holder would have to pay congestion charges if its load is greater than expected. The Commission's proposed approach would incent transmission rights holders to hoard rights. New entrants to the market and those without transmission rights would have little alternative but to buy rights directly from the RTO on the short-term market or pay actual congestion charges. This means that new entrants to the market would face higher transmission costs and more transmission price risk than existing rights holders.

The Commission should provide documentation of the specific market mitigation measures it proposes to be implemented. Parties should have the opportunity to review and comment on the specific proposals before a NOPR is issued.

The Working Paper provides little detail on the mitigation measures the Commission envisions using. Parties need additional specificity on the market mitigation measures that the Commission is considering or might consider.

The Commission should provide detailed documentation of how it proposes to resolve the issues involved in the transition to new service. Parties should have opportunity to review the specific proposal before the issuance of a NOPR or tariff language.

The Working Paper provides no details or information on how the Commission proposes resolving a number of critical transition issues. These issues are crucial to getting the various parties to agree to an RTO. For example, non-jurisdictional utilities in the Northwest have made it clear that the transition of customers under existing contracts to new Network Access Service and the allocation of existing transmission rightsare make - or-break issues for them. The Commission should provide early guidance as to how it will address these issues.

RTOs should rely on market-driven mechanisms to promote and fund least-cost investments in the system. Only if market-driven mechanisms fail should the Commission allow RTOs to direct investments and broadly allocate the costs of new investments.

The Commission proposes to require RTOs to pursue least-cost methods to "cause construction of needed transmission and generation facilities or demand responses" and states that "RTOs would choose an ultimate solution, whether generation, transmission, or demand side."

While we support the aim of promoting timely, least-cost system investments, we disagree that the RTO should ultimately decide what projects are undertaken. We believe that the appropriate role of the RTO is to craft a long-range plan and provide efficient price signals to market participants. Load-serving entities and other market participants are better suited for directing what specific investments are made to relieve congestion and maintain reliability at the lowest cost. Such a market driven approach is also consistent with least-cost planning requirements imposed by many states.

The Commission should formally work with the states to address the issues surrounding long-term generation adequacy.

The Working Paper sets forth principles for ensuring long-term generation adequacy but offers no prescriptions. We believe that this is a central issue for market design. Before issuing a NOPR, we recommend that the Commission sponsor panels with the states to thoroughly evaluate the issues and options related to long-term generation and transmission system adequacy.

DATED this 10th day of April 2002.

Respectfully submitted,

Roy Hemmingway	Joan Smith	Lee Beyer
Chairman, OPUC	Commissioner, OPUC	Commissioner, OPUC

Michael Grainey
Director, Oregon Office of Energy
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