Public Generating Pool

Position Paper on RTO West

Draft Proposal for RTO Congestion Management "Dry Run" Exercises

Residual Congestion Management by RTO West

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Introduction and Summary

This paper represents the positions of the Public Generating Pool (PGP) regarding the possible formation of a Regional Transmission Organization (RTO) in the Northwest.[1] The PGP members have been active in the various workgroups associated with RTO West, including the Regional Representatives Group.

The PGP is seriously concerned about many aspects of the current proposal for RTO West, including the continuing uncertainty over basic issues such as congestion management, the likely costs of operation, the lack of any perceived or real benefits, the potential for complexity without purpose, impacts on regional power prices, the potential for market power to be created and exercised, and the overall uncertainty associated with the formation of any new institution. As a result, the PGP has concluded that now is not the time to engage in risky and disruptive administrative exercises in response to unnecessary federal regulatory initiatives.

Forming an RTO is not necessary for the Northwest. The operation of our transmission system and regional power markets will not be enhanced or improved by an RTO. Even worse, forcing an RTO onto the Northwest may easily cause long-term damage.

If an RTO is not formed in the Northwest, existing institutions are capable of addressing transmission issues, including the critical need for additional transmission and generation capacity. It is important to remember that BPA is planning a significant increase in its investments in transmission capacity without an RTO. The Northwest should work to improve existing institutions, rather than launching new ones. However, we realize that others feel differently, and that federal regulatory mandates may require some change in the institutional structure. To address this possibility, the PGP has prepared this paper, which is intended both to communicate our principles and to educate the reader on some of the critical issues, concepts, and proposals.

The remainder of this paper lays out a few basic principles, and then goes on to discuss major issues and lays out principles in the main areas under discussion regarding RTO West: congestion management, pricing, planning and construction, costs and benefits, ancillary services, adjacent control areas (seams), billing and settlements, BPA's involvement, and potential impacts on Northwest hydro operations.

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[1] The members of the PGP are Cowlitz County PUD, Douglas County PUD, Grant County PUD, Pend Oreille County PUD, and Seattle City Light.

Basic Principles

1. Scope of the RTO: should be minimal to start; can be expanded if both necessary and cost-effective

2. Timing of implementation: should occur only after adequate preparation and resolution of disputes regarding the translation of current transmission rights into the RTO framework; should depend on thorough and successful testing of new commercial and operational mechanisms in parallel with existing institutions

3. Complexity of procedures: should accurately reflect both current rights and the operation of the transmission system

4. Protection of current rights: must be absolute, subject to the option for current rights holders to exchange their current rights for rights in the RTO system

5. Cost-benefit analysis: must be performed; a substantial benefit-cost ratio must be demonstrated with a high degree of confidence

6. Ability to "remain outside" the RTO: must be retained for both publicly-owned control area operators, transmission customers, and owners of secondary, lower voltage transmission facilities

Congestion Management

The PGP's strongest preference is to relieve congestion through the construction of additional transmission and generation capacity, rather than the formation of new, costly, and burdensome administrative "solutions" with highly uncertain results. However, if efforts continue to form RTO West, the PGP's position on congestion management is as follows.

This function is one of the fundamental building blocks of any RTO: the definition of new "property rights" that would replace the current structure of rights defined largely by transmission contracts, but also derived from the obligation of utilities to serve retail loads. Current rights are based on the "contract path" fiction: power is injected into the grid at specific points and withdrawn at other points with system impacts typically limited to a commercial path defined in the contract. This is a fiction because power flows through an interconnected transmission network follow the laws of physics, not of contracts.

Before systems can be designed (for assignment or auction, pricing, and scheduling) to implement any new system of property rights, the new rights themselves have to be defined, and agreement reached on the proper way(s) to translate current rights into new rights. Those entities holding such pre-existing contract rights (e.g., utilities and power marketers) are concerned that the new system of property rights will not fully replicate current rights or may cost more if current rights are fully and accurately replicated.[2] Those entities without such current rights are concerned that the process of "translating" current rights into new rights will provide more services than are currently available, may result in over-subscription of transmission capacity, and could thus reduce or even eliminate their access to transmission capacity and thus energy markets.

Following are the PGP's principles in this area:

1. Completeness All existing contract rights must be identified, including many that do not fit easily into standard categories (e.g., O&M obligations at specific substations). Existing transmission rights include *pro forma* Network and Point-to-Point contracts, pre-Order 888 contracts (Integration of Resources, Formula Power Transmission, and Use-of-Facilities), bundled delivered power contracts, and more limited rights to cross specific buses. Any new system should assure that current rights are fully "grandfathered" into the new system. Anything less would unfairly shift costs among end-users.

2. Accuracy Any system to replace the contract path model, such as congestion zones and flowpaths, should accurately reflect the realities of electrical flows. It may be that the new system is highly complex in concept, but that would be appropriate if it is accurate. A goal of simplicity should not be used to justify a system that just turns the problems of congestion management over to the RTO, because of the risk of repeating the "California experiment": a single entity that can be held hostage to the forces of market power. At a minimum, all currently "managed" (congested) paths should each have property rights in the new system.

3. Unbundling In order to achieve accuracy, it may be necessary to define more than a dozen congestion zones and dozens of interconnections among these zones (called flowpaths). Although the result may be highly extensive "unbundling" of transmission capacity, market participants should be free to "rebundle" these rights to maximize their value. It is expected that these rebundled rights will have to change over time to reflect changes in loads and resources, and decentralized decisions are more likely to maximize value in this process than a centralized RTO.

4. Preservation of existing rights The new system of transmission rights will have to evolve to reflect changes in loads, resources, and grid characteristics. However, such evolution cannot be allowed to diminish pre-existing rights, both grandfathered and auctioned FTRs. In addition, existing and new rights holders must be given adequate notice of any changes in grid topology that could affect their rights.

5. RTO management of congestion The RTO should have the minimum necessary responsibility for managing the commercial aspects of congestion. Any costs of "residual congestion management" by the RTO should be recovered as much as possible from those entities who do not manage congestion on their own, and either choose to have the RTO take actions on their behalf or allow the RTO to manage congestion by default. It may be practical to recover residual congestion costs from

[2] Of course, the new system could also cost more while providing fewer rights than today.

the entities making use of the grid in a particular zone, but the zones should be as small as possible, and there should be no RTO-wide "uplift" of these costs.

6. Auction process The RTO should use a form of open, simultaneous, ascending price auction to sell off unassigned FTRs on identified flowpaths. This form of auction is best able to (a) communicate value through bids and (b) maximize revenues because rights to interdependent flowpaths and, possibly, time periods would be sold at the same time. Care would be necessary to avoid collusion, but mechanisms are available to mitigate the potential for the exercise of market power through the auction.

7. Feasible dispatch Network customers (both NT and PTP) with inherent flexibility to shift among PORs should have that flexibility reflected in the initial assignment of FTRs. In addition, entities with obligations to serve (e.g., retail utilities) should have the right to be assigned additional FTRs for retail load growth, because these rights are inherent in today's arrangements. These two principles (flexibility and coverage of load growth) will create numerous practical problems in implementation.

8. Need for test runs Once agreement is reached on each of the above issues, it is critical to set up "test runs" or "dry run exercises" of the resulting congestion management system, to determine if adjustments are necessary before any attempt at commercial implementation. These test runs can be conducted on a limited number of paths, but should be designed to check "boundary conditions": the performance of the congestion management system in extreme circumstances, such as the failure of a critical transmission or generation facility. Ultimately, test runs can be conducted and more frequently, and over a wider number of paths, so that the transition to any new system can be as seamless as possible.

Pricing

In place of the existing structure of pricing and paying for transmission service, the RTO would implement a system of Company Rates (load-based charges for the use of existing transmission owners' systems) and Transfer Payments (transfers between RTO participants based on current payments), which are intended to mimic (almost exactly) the current flows of revenues. However, there are many unanswered questions about the pricing and payment structure.

1. Cost shifts Although any new pricing structure will have some unplanned effects, the basic design should not seek to alter current payment streams (directions and amounts). To do otherwise would be a "cost shift". Specifically, the new pricing structure should not attempt to recover transmission costs from entities that are not currently paying those costs, nor should the new pricing structure seek to extend payments where they would otherwise cease automatically under existing contracts and regulations. For example, BPA's transmission rates are differentiated slightly by voltage, with those customers taking service at lower voltages paying a surcharge that reflects the additional costs of transformation. The RTO's pricing structure should

not try to undo this arrangement. Similarly, BPA has transmission contracts in place with regional investor-owned utilities that provide for the delivery of federal power to preference customers; while there may have been good reasons for such arrangements in the past, it should be expected that under the RTO all customers must pay their full share of the cost of transmission service to reach their loads. Therefore, when these contracts expire they should be replaced with standard RTO service.

2. Fees for new generators Currently, a new generator seeking long-term transmission service will normally seek transmission contract rights, and will pay for those rights. The fixed costs of the transmission system are covered in part by these new revenues, and the new RTO pricing system should seek to recover a proportionate share of the fixed costs from new generators in the future as well, unless the new generator can demonstrate that loads are covering a higher share of the fixed costs through payments for additional transmission service. Similarly, new generators would pay the respective Company Rate to export power from the RTO area.

3. Export fees Stage 1 of RTO West finished without a consensus on the need to analyze export fees. During Stage 2 (and following), this concept must be explored further, in order to ensure that an appropriate share of the fixed costs of the transmission system are borne by those marketing to loads outside the Northwest.

4. Voltage-differentiated rates In retail rate-setting, customers taking delivery at different voltages normally pay different distribution charges, reflecting the different costs of service. There is no reason why this concept cannot and should not be extended to the wholesale level. To do otherwise would require those utilities taking service at higher voltages to effectively subsidize those taking service at lower voltages, and would send price signals that are not based on the cost of service.

5. Uplift The RTO's basic costs of service should be recovered from all users of the RTO system, and should be charged on a $/MW/hour basis to those using all forms of Transmission Rights (i.e., FTRs, RTRs, and NTRs).

6. Losses The marginal cost of losses for any transaction is determined by total loading on the system, marginal energy prices, the direction of the power flows, and the size of the transaction. The current method of assessing losses using an annual average loss factor will not adequately provide for losses incurred during each operating hour, thus burdening control areas with unaccounted for energy consumption. During heavy load periods, transactions causing incremental flows on heavily loaded transmission lines can result in losses that are an order of magnitude greater than the system annual average loss factor. The RTO must develop an effective system of assessing loss responsibility on a time-differentiated basis so that all market participants are able to accurately settle their loss responsibilities on a timely basis, without burdening the RTO or other adjacent control areas with excessive unaccounted for energy consumption.

7. Company Rates In order to accurately reflect changes in the cost of service, Company Rates and Company Loads should be recalculated annually. Because of the cost and complexity of a BPA transmission rate case, BPA's Company Rates should be adjusted in part through the use of an adjustment clause, rather than a complete 7(i) process.

Planning and Construction

The role and authorities of the RTO in terms of planning and expansion of the transmission system are a subject of considerable debate. These functions are currently performed by transmission owners, and these owners would continue to have planning responsibilities for some facilities. In addition, the current regulatory system requires transmission owners to build new facilities when necessary to provide requested service. Thus, it is not clear yet how much authority the RTO requires, in order to ensure a highly reliable transmission system.

1. Facilities inclusion Some entities in the Northwest are advocating an "expansive" approach to the identification of facilities that should be under the direction of the RTO. There are three types of risks associated with this expansive view. First, the operation of facilities owned and operated by publicly-owned utilities may be interfered with. Second, the costs of lower voltage or secondary transmission facilities may be shifted to the customers of utilities who do not use these facilities. Third, the RTO's planning functions may experience growing pains. For these reasons, the PGP supports a more limited definition of facilities to be included in the RTO. If transmission users experience reliability problems, these should be addressed by working directly with their transmission providers, rather than a regional organization that may be inclined to spread the costs of local problems across all regional loads.

2. Backstop role The strength of the RTO's authorities in planning and construction should be "earned", rather than assigned. That is, the RTO's initial authorities should be limited, because it is not clear how cost-effective the new organization will be.

Costs and Benefits

The cost/benefit study in Stage 1 did not reach a satisfactory result, in part because there was insufficient attention paid initially to the correct economic framework, and in part because changes were made to the study at the "last hour" that did not receive the support of the entire work group. BPA has a responsibility as a federal agency to ensure that its actions do not cause unnecessary costs to be paid by consumers in the region; in addition, the state regulatory commissions have a responsibility to ensure that the participation of regional IOUs in any RTO is in the public interests. Thus, a framework for economic analysis should be established early, and that framework used to conduct appropriately detailed analysis of the Stage 2 proposals. This framework would include the following items:

1. Economic welfare accounting apply the NED perspective (national economic development) in the economic accounting business: the expected change in consumer surplus plus producer surplus, measured for the service area of RTO West as a whole, plus significant subregions (e.g., U.S. vs. Canada, NW versus rest of WSCC)

2. Regional economic effects in addition, make RED (regional economic development) calculations (i.e., changes in employment and income) for specific states or subdivisions of the Northwest

3. Effects on consumers identify the ways in which consumer surplus is expected to change: roughly (a) the change in the delivered price of electricity plus (b) the change in the likelihood of service interruptions

4. Effects on producers identify the similar types of calculations for changes in producer surplus, which have to be tracked through to those who will actually receive the surplus: stockholders of private corporations, who will live all over the country (and the world), employees of NW corporations (who might get increased salaries), producers who are not able to move their operations outside the region (e.g., agriculture)

Ancillary Services

Ancillary services (generation) are required to operate the transmission grid in an equitable and reliable manner. Transmission customers currently self-supply these ancillary services or purchase them from the transmission provider. The RTO may have a role in the procurement and supply of these ancillary services.

1. Obligation The RTO should have only a "default" obligation. Scheduling coordinators (SCs) should have the option, as transmission customers do today, to self-supply these services. The RTO's normal operations should assume that SCs will self-supply these services, or will purchase them from third parties. The RTO should not take other actions to "make" markets in ancillary services. The RTO should establish reasonable and non-discriminatory performance standards for SCs, but should only be allowed to collect financial sanctions for non-performance to the extent that the RTO pays financial sanctions to SCs and adjacent control area operators for the RTO's failure to perform.

2. Procurement The RTO should take actions to permit the provision of ancillary services on a default basis, including the execution of contracts with generation owners that allow the RTO to turn to such owners in the event (and only in the event) that SCs do not self-supply required ancillary services or arrange for third parties to make such services available to the RTO. Such procurement by the RTO should be based on competitive bidding to the maximum extent possible.

3. Cost recovery The RTO's costs of providing ancillary services, including energy imbalance, should not be recovered through the generalized "uplift" charges, but

should be targeted on those customers who either request the RTO to provide these services, or who through inaction fail to bring sufficient ancillary services to the RTO.

4. FTRs for reserves and other ancillary services Existing regional reserve-sharing pools provide significant economies to their participants by recognizing the diversity that exists in the interconnected generation and transmission system. Once a congestion model is developed, it should be tested against the reliability and economic effects of current reserve-sharing pools, before determining how transmission should be managed for the delivery of reserves and other ancillary services.

Adjacent Control Areas (Seams)

Existing adjacent control areas should not be forced into relationships with the RTO. The RTO should not be authorized to require dispatch of non-RTO generators that are interconnected with the RTO control area (e.g., Seattle, Tacoma, Grant, Douglas, or Chelan). If an emergency arises, the RTO could be authorized to request redispatch of such generators, but non-RTO operators of adjacent control areas should be permitted to judge whether or not damages (e.g., to generators, infrastructure, or end-users) would occur, and if so, to decline the request. Definitions are required for “emergency” and “damage”. In addition, the following issues need to be addressed in bilateral contracts to be negotiated between the RTO and adjacent control area operators (Seattle, Tacoma, Grant, Douglas, or Chelan).

1. Implementation of dynamic scheduling. Any RTO congestion management and scheduling systems should not interfere with existing dynamic scheduling procedures and protocols, and should be comparable or superior to existing procedures.

2. Frequency response, voltage control and contingency reserves. RTO West and all adjacent control areas should be held to the same control area and reliability performance standards.

3. Financial aspects. RTO West and adjacent control areas should face the same commercial consequences for any violation of performance standards. RTO West may negotiate with adjacent control areas for services to be provided by the adjacent control areas; the RTO shall compensate adjacent control areas for any such services provided.

Billing and Settlements

The schedule for billing and settlements currently contemplated by RTO West will result in excessive delays between the time that service is provided and when final settlement occurs (45 days for invoicing, 86 days for settlement). Given current off-the-shelf technology (i.e., electronic metering, telemetry, and computers), much shorter settlement timeframes are feasible.

BPA's Involvement

Many of BPA's preference customers have requested that BPA provide Scheduling Coordinator services. While it is not clear that this is an appropriate entrepreneurial role for a federal agency, such provision is acceptable if it meets a fundamental principle: all of the costs and risks associated with BPA's provision of such services should be borne only by those customers who have elected to purchase such services from BPA. This will require the establishment of a separate business line at BPA, which will purchase services from the rest of the agency and manage its costs and risks separately from the TBL and PBL. For example, there is the risk that any SC will make mistakes in scheduling, which could be reflected in significant imbalance charges depending on the state of energy markets. The risks of these imbalance charges should not be borne by any BPA customers except those who have chosen to be customers of the SC business line. BPA should be ready to shut down the SC business line if its fails to cover its costs of operation.

Before BPA can execute any obligations with the RTO, all applicable statutes regarding major decisions of the Administrator must be complied with, including NEPA. Because of the length of time that has elapsed since the last major environmental review, and the changes in the industry since then, BPA will probably have to prepare a new EIS.

Potential Impacts on Northwest Hydro Operations

If RTO West is formed, it should be prohibited from adopting transmission practices or rates which might conflict or interfere with operations under existing regional coordination arrangements. These arrangements also provide an operational framework that tends to complement regional fisheries programs and other non-power uses for water resources (federal and non-federal).

A. Pacific Northwest Coordination Agreement (PNCA). The PNCA coordinates the planning and operations of the Pacific Northwest hydroelectric resources on a monthly and annual basis. The purpose of this agreement is to achieve optimal firm load carrying capability and to produce optimal amounts of usable secondary energy. Each resource owner is entitled to generation equivalent to the firm output of its own resources over an operating year, but on a period-by-period basis an owner may have obligations to deliver some of its own generation to others or may have entitlements to generation from resources owned by others. These obligations and entitlements are identified as interchange, in-lieu energy, provisional energy and storage energy. The PNCA has specific transmission priorities and rates designed to accommodate the use of these coordination exchanges to achieve the most cost-effective operation of the Pacific Northwest hydro-thermal power system. If transmission practices or rates are adopted that interfere with these coordination exchanges, the Pacific Northwest may suffer load loss or hydro-electric energy losses due to spills and head loss, as well as increased use of fossil-fueled non-renewable resources.

B. Mid-Columbia Hourly Coordination Agreement (MCHCA). The MCHCA coordinates the operations of the seven Mid-Columbia projects: Grand Coulee through Priest Rapids. This agreement was the result of assurances given to the non-Federal parties downstream of Grand Coulee Dam that, when the Grand Coulee Project's third powerhouse was constructed, BPA would enter into agreements to secure optimal usable generation of the affected downstream projects and equitable distribution of the resulting benefits. Under this agreement, the seven plant system is operated to meet the combined load request of the seven plants according to algorithms developed by the parties. Under this agreement, no transmission charges are applied to energy delivered or received among the projects. If there were any transmission limitations imposed on these transactions or charges imposed for them, parties would not receive the full benefits that they have been assured of receiving and coordination could be diminished. In such an event, the Pacific Northwest would suffer energy losses due to additional risk of spills and head loss.

C. Mid-Columbia Trading Hub. The Mid-Columbia bus is the system of non-Federal transmission and switching stations interconnecting the Rocky Reach, Rock Island, Wanapum and Priest Rapids Dams on the Columbia River. It is currently used as the point of delivery for the NYMEX Mid-Columbia Electricity Futures delivery location, and is also used as the delivery point for many other energy transactions. Considering this network as a single bus allows power and energy to be received at any point between Priest Rapids Dam and Rocky Reach Dam and delivered to another party at the same or any other point along the Mid-Columbia bus without having additional transmission charges imposed. One of the primary factors influencing the efficiency of a market is the volume and liquidity of transactions. Any restrictions or charges imposed on these transactions for use of the Mid-Columbia bus would discourage transactions and reduce the efficiency of the market.

Draft Proposal for RTO Congestion Management "Dry Run" Exercises

There is considerable concern that any congestion management model for RTO West will impair reliability, create or expand market power, and/or prove commercially or practically unworkable. In order to avoid these outcomes, "dry run" exercises should be planned for a limited number of paths, to test the main components of the congestion management model.[1] This paper provides a draft outline for applying this concept to RTO congestion management.

1. Pick candidate paths or transactions; examples might include the following:

   - Bridger to Salt Lake City (larger transactions, Path C, impacts on Idaho, seam with WAPA)
   - FCRPS to Ashland (smaller transactions but with impacts on NJD, Mid-C, PacifiCorp's south Oregon system, and possibly COI; GTA customer; possible seam with CA-ISO)
   - FCRPS to Burley area (NW-ID impacts; summer peaking)
   - Colstrip to Puget Sound (major E-W path)
   - BCH to COB (major N-S path)

2. Identify all existing rights on the related path(s)

3. Convert the existing rights into FTRs

4. Calculate FDFs

5. Calculate ATC (for the RTO's auctions)

6. Set up and run the auction mechanism for various time periods

7. Test the entire structure under "boundary conditions": e.g., generator or transmission outages, Siberian Express loads, above-average water conditions

8. Assess the amounts of residual congestion to be managed by the RTO (see the separate paper on principles for residual congestion management)

9. Test implementation of the RTO's residual congestion management system

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[1] Similar exercises have been underway for the Slice power product since last year, for the same basic reason: the Slice represents a substantial change from pre-existing power products.

<u>Residual Congestion Management by RTO West</u>

Principles for "residual congestion management" are required, in order to provide sufficient direction to the RTO in the initial phase of operation. Here's a start.

First, the RTO should be required to take offers from FTR holders who have scheduled on the congested path, to see if sufficient FTRs can be purchased (i.e., schedules reduced) to clear the problem.

> Although there is a potential problem if there is only one or a few such "bidders" (i.e., entities who are willing to offer FTRs) on a given path, the potential size of this problem can be reduced, and perhaps the entire problem eliminated, if the congestion zones are sufficiently small and the number of flowpaths sufficiently large. Current contract rights are sufficiently dispersed that creation of FTRs to reflect such rights should result in fragmented ownership of FTRs, and thus competition in the offer of FTRs (schedule reductions) to the RTO. If such fragmentation does not occur, then it may be necessary for the RTO to have procedures in place to address market power in the FTR market.

Second, the RTO should rely on auctions that entertain bids for "incs" and "decs" to redispatch generation and/or curtail loads.

> The RTO should establish procedures that ensure participation in such auctions from the demand side of the relevant market. If the relevant market, defined for a specific congested path, is sufficiently competitive, then it will be possible to rely on the bids to clear the congestion in an economical manner. If the relevant market is <u>not</u> sufficiently competitive, then the RTO will have to develop procedures to address market power. There may be circumstances in which generation within the RTO control area will have to be subject to "reliability must-run" (RMR) contracts. If possible, it would be advisable for the RTO to combine these processes for bidding FTRs, "incs", and "decs" to enhance competitive market forces. Congestion may take the form of energy, but may also involve other products (ancillary services), so it may be necessary to have auctions that (separately and together) address all of these products.

Third, if the above mechanisms are not sufficient to clear the residual congestion, *pro rata* curtailments should be implemented on the congested path.

Implementation of these principles will require at least the following steps.

1. the development of more detailed written procedures that will implement the above principles as well as the following;

2. the development of specific auction mechanisms, including software, hardware and protections against the practice of tacit or explicit collusion through the bidding mechanism;

3. the development of criteria for identifying relevant markets (geographical and product);

4. criteria for establishing that the relevant markets are or are not sufficiently competitive;

5. establishment of necessary authority for the RTO to shift from the auction mechanism or mechanisms to a "must-run" type of contract with owners of specific generators or other entities;

6. agreement on principles for such "must-run" contracts;

7. negotiation of such "must-run" contracts; and

8. development of principles that would allow such "must-run" situations to be shifted or switched to auction mechanisms, upon the determination that criteria had been met that demonstrate sufficient competition.