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#### BPA/PUBLICS MEETING

BPA presented a preliminary customer involvement plan for its proposed scheduling coordinator (SC) service. An SC is a 24hr/day, 7day/wk operation that is needed to provide individual transmission customers with a host of products including scheduling transmission and ancillary services with RTO West in aggregate; assuring aggregate schedules balance (i.e., providing balancing energy to match loads and resources); modifying schedules as required by RTO West; and submitting load forecasts (daily/hourly type rather than the 20-year planning type).

This service, which is more than scheduling agent services alone, has been provided by BPA for most of its customers as part of doing business, and the costs have been recovered in rates. Public power reps are working with BPA to identify issues associated with providing this service, and trying to find the best approach to meeting with its customers to explain exactly what is involved. Every customer will need an SC, and BPA expects to offer this service at a cost-based charge. Although an original commitment was made to offer this service to full and simple partial customers only, BPA has not closed the door to offering the service to complex partial or slice customers.

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#### ANCILLARY SERVICES

"Reserves" consist of the four ancillary services: regulation, load following (up and down), contingency reserves (spinning/non-spinning reserves), and replacement reserves. An SC will use these four services to provide Balancing Energy Service, a service which maintains short-term load/resource balance caused by daily load cycles, load forecasting errors and fluctuations in load. Reserves must be available on a continuous basis to fix these imbalances. RTO West will determine reserve requirements to cover imbalances on a zone-by-zone basis. [Ed. note: I think BPA now determines reserve requirements based on its entire load. So how does moving to a zone-by-zone basis improve, rather than complicate, today's utility practice?] All SCs must identify sources of reserves (like Grand Coulee Dam) zone.

Here's the rub . . . If the SC (BPA) must deliver Balancing Energy (i.e., reserves) from one zone (Coulee) to another zone (South Oregon), transmission is required to get there. If the transmission path is congested, the SC will need -- \*ta\*da\*! -- FTRs. Lots of problems here, such as who is financially responsible for acquiring these FTRs and what happens if an SC doesn't have enough of them.

Moreover, WSCC is reviewing the operating reserve requirements in its Minimum Operating Reserve Criteria, so it's possible that RTO West's ancillary services will be influenced by WSCC changes. For example, WSCC is thinking of eliminating the 5% hydro/7% thermal requirement for contingency reserves; eliminating the distinction between interruptible and firm loads when using loads as contingency reserves [Ed. note: \*W\*H\*A\*T\*?? Firm loads can be interrupted if needed? \*ROLLING\*BLACKOUTS\* are the answer to the need for reserves?]; and eliminating spinning reserves in favor of what is called Frequency Response Reserve. [Ed. note: It smells to me as if the sum of the unbundled parts -- and therefore the cost for them -- is greater than the whole; and, worse, that the transmission system will be guaranteed unreliable from the get-go. I hope my lights go out before the region's lights go out.]

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#### BILLING & SETTLEMENTS

A proposed timeline for billing was presented. RTO West will bill SCs (such as BPA), and the SC will bill individual customers. Key issues right now are finding a timeline that will get bills out and revenue in as quickly as possible, while making sure there is enough time to assure sufficient time to collect, review and correct data for billing accuracy.

There are some questions about matching up the billing process between the new RTO system with the existing BPA system. For example, BPA allows 20 days for paying the bill. RTO West wants its money faster than that.

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#### MARKET MONITORING

All day session scheduled for Friday, Car Talk Day, so news will have to wait until next week. The agenda included discussing lessons learned from California and review of other market monitoring plans such as Pennsylvania-New Jersey-Maryland and Desert Star (DStar).

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#### SCHEDULING

The group agreed to continue working off of DStar documents. A few notable differences between DStar and RTO West are the number of flow paths (DStar has significantly fewer flow paths than RTO West) and the definition of what can go into Recallable Transmission Rights.

The group reviewed the DStar Scheduling Appendix and flagged issues that may cause problems or need attention. Much discussion was dedicated to the day-ahead scheduling process. At some point, perhaps a day ahead, RTO West will announce the number of FTRs that are available for purchase. In order to do so, RTO West will be forecasting loads, generation and general systems information. How RTO West treats this information (publishes it or keeps it private) was a hot topic. The group agreed that RTO West should publish some information on system conditions (i.e., planned transmission outages should be announced, etc.). Some questions remained unresolved: what level of data should be public information? how often should it be published? how often should RTO West publish its updated distribution matrix?

No one was sure how far out RTO West will need to forecast (the assumption is that it will do at least hour-ahead and day-ahead forecasts). There was some question as to whether RTO West or the SCs will be doing the forecasts. The group was troubled that the SCs would continually lowball an estimate of available FTRs to avoid recalls. Consequently, if RTO West uses numbers reported by the SCs, it may need to develop a mechanism that encourages accurate forecasting.

A subgroup is working on scheduling compatibility issues between RTO West, the California ISO and DStar. Currently, very few of the activities line up between the RTOs. Timing could become very important when considering market incentives across RTO regions.

The group discussed whether an interchange authority is an entity or a computer program [Ed. note: !!!] There seemed to be consensus that an interchange authority is an entity and that RTO West would have exclusive control over this function. [Ed. note: !!!!]

The group flagged an issue on the SC tariff provisions. The group felt that restricting each meter to one SC was putting undue limitations on scheduling. A question arose as to whether there ought be limitations on how often customers switch SCs. Some thought that there should be limitations to reduce instances of double scheduling. Issues of gaming and market abuse were touched on and the group agreed that it is going to be important to have a mechanism in place that allows RTO West to validate information provided by SCs and generators. The group agreed that RTO West will face technical limitations in this area. If everyone is changing SCs on an hourly basis, the RTO will have a difficult time getting a forecast out. No consensus was reached; pros and cons of each position will be presented at the next meeting.

The issue of transmission losses will be considered by this group, as well as by the congestion management group.

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#### PLANNING

The group agreed that RTO West will take an active role in providing rough cost estimates for potential expansion projects. There was some concern that providing this type of information would require an expensive staff. To keep costs down, the group agreed that RTO West will do "back of the envelope studies" and attach disclaimers and disseminate the info to all interested parties.

In stage 1, it was decided that RTO West would be responsible for allocating the costs of expansion projects to the parties that benefit. After stepping through several scenarios, the group concluded that the only time RTO West will allocate expansion costs is when the project in question is solving an adequacy problem. The main problem is that it is difficult to distinguish between a free rider from a party receiving unsolicited benefits. Many asserted that the new construction had to be displacing a project that was in the works. Others felt there are problems with this approach. This discussion will continue.

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#### CONGESTION MANAGEMENT

Many important questions were raised:

- \* What are FTRs? Are you buying rights to use a flow gate, or are you buying rights to inject into and withdraw off of the system?
- \* Are non-converted rights different from FTRs? If so, how?
- \* What is a feasible dispatch?
- \* How often can a party review its feasible dispatch assumptions?
- \* What is a schedule? What is a transaction?
- \* Does the system being proposed create incentives for parties to hoard FTRs? FERC Order 888 requires parties to take transmission rights to the market under certain conditions (e.g., when FTRs are not being used). Under RTO West, parties do not have an incentive to take their FTRs to the market. The group discussed possible mechanisms to solve this problem. RTO West could simply take FTRs if the FTRs are not being used and sell them as RTRs (probably in the hour ahead market). This revenue would not be returned to the FTR owner. But if the FTR owner released the FTRs to RTO West by a certain time, the owner would receive the profits from the sale. Is this mechanism adequate? Will the parties hoard FTRs in order to gain market power?

Most of these questions were not answered to the satisfaction of the group. A "large" small group meeting is scheduled for Tuesday, March 6th from 9:00-4:00.