UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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| Long Term Transmission Rights in<br>Markets Operated by<br>Regional Transmission Organizations<br>and Independent System Operators | Docket No. AD05-7-000 |

NOTICE OF ADDENDUM TO STAFF DISCUSSION PAPER

(May 31, 2005)

On May 11, 2005, Commission staff released a staff discussion paper titled "Long-Term Transmission Rights Assessment." Attached to this notice is an addendum to the staff paper that clarifies a few sentences in the staff paper and provides a brief summary of the Southwest Power Pool market design proposal.

Linda Mitry
Deputy Secretary

**Addendum To**
**Long Term Transmission Rights Assessment**
**FERC Staff Discussion Paper**

**May 31, 2005**

On page 7, footnote 10 reads as follows:

"The exception is New York ISO, which offered FTRs with 2 year and 5 year terms during the Fall 2000 FTR auction. These multi-year rights were not offered subsequently. See discussion in Appendix B."

Appendix B discusses the current FTR allocation rules of the New York ISO, but it does not discuss the ISO's Fall 2000 auction of FTRs with 2 year and 5 year terms. The staff team understands that one reason why such multi-year FTRs were not offered subsequently is that a small number of market participants were able to lock in valuable rights for several years at a low cost. This lead to equity concerns. However, recent discussions with the New York ISO staff suggest that market participants are ready again to include multi-year rights in the FTR auction.

On page 11, footnote 12 reads as follows:

"In general, the revenues from ARRs or FTRs will follow the load when it changes suppliers. The details of how this is done vary by RTO, as detailed in Appendix B." Appendix B does not include a discussion of each RTO/ISO's rules for ensuring that ARRs or FTRs follow load when it changes suppliers. However, this issue is discussed in general terms in Appendix A, page 6.

On page 18, paragraph 1 refers to a discussion of the SPP market design in Appendix B. That discussion was inadvertently left out of Appendix B. The addendum to Appendix B below provides that discussion.

## Southwest Power Pool

SPP's market design is still in the development stage.[1] Hence, this summary is not intended to suggest that this process is completed, nor that the final design will correspond to this proposal.

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[1] SPP's market design is still being developed by the SPP working groups. The information here was gathered from documents posted on SPP's website and from conversations with SPP staff.

The SPP design now under discussion has features in common with the eastern RTO markets, such as a bid-based security constrained dispatch with locational prices, but it employs financial transmission rights in a different manner. Instead of granting FTRs in a monthly or annual process, SPP plans to give participants financial rights to hedge congestion costs on a daily basis, based on their current scheduling rights under the SPP OATT. When these daily rights are settled through the spot market, they will be financially equivalent to the FTR obligations in other RTO markets. Hence, the long-term rights will continue to be the OATT Network Integration Service (NITS) scheduling rights, while the short-term rights to hedge congestion will be akin to FTRs.

**Daily Transmission Rights**

There would be no allocation of a fixed amount of financial rights *per se*. Instead, participants with OATT NITS are allowed to schedule as permitted under the NITS between designated resources and load receipt points and receive a financial hedge for the amount scheduled. Participants can submit schedules day-ahead and revise schedules up to 30 minutes prior to the operating hour. A participant's schedule must be within its rights under its OATT service. It will not pay congestion costs for its scheduled amount and can bid into the energy spot market to be instructed to deviate from its schedule if cheaper generation options are available. SPP will settle the spot market based on locational prices.

SPP plans to implement longer term FTR rights (i.e., term greater than one day), subject to a finding that FTRs would be cost beneficial, in Phase 2 or 3 of their market development process. SPP currently has no plans to award specific transmission rights associated with grid upgrades or to auction transmission rights. SPP will use a process to determine upgrades needed for a resource to be designated as a network resource and the cost allocation associated with the upgrades. An entity will have the scheduling rights associated with those network resources.

**Scheduling Requirements**

As with the FTRs used in other markets, the SPP scheduling rights protect the participant from congestion costs associated with their schedule. Deviations in the real time market from scheduled levels would be settled based on locational prices. As such if an entity schedules and follows its schedule exactly, it will not be subject to additional congestion charges in the market. If an entity with a schedule bids into the market and is not dispatched (or is dispatched at a lower level than its scheduled level), it would have to buy the difference at the nodal price from which it scheduled.

In markets with locational pricing, physical scheduling rights that offer perfect congestion hedges could be used to accrue positive payments from the spot market by submitting a pre-dispatch schedule for transmission different from what is actually used. SPP's rules impose daily financial settlement requirements that prevent participants from claiming an undue amount of transmission rights when scheduling. Participants will not be able to benefit from congestion revenue associated with the portion of any schedule not within 4% of actual metered firm load obligation when congestion occurs. If schedules violate the 4% threshold, then the participant's schedule will be financially settled such that the participant does not benefit economically from the over-scheduling or under-scheduling of generators.[2]

**Reducing Schedules based on the Transmission Loading Relief Procedures**

SPP working groups are in the process of developing a method for curtailing schedules when transmission loading relief procedures are needed. Like other RTOs, SPP cannot dispatch generators associated with physical schedules if they haven't been offered into the spot market (in other RTOs, this is called self-scheduling). Curtailment protocols are needed because, unlike other RTOs, SPP only assigns transmission rights based on the daily transmission capability, taking into account curtailment priority.[3] This

[2] SPP will identify participants that over-schedule (that is, submit a schedule prior to the dispatch hour but then consume less than the scheduled amount) and not pay them for the payment benefits they accrued due to the over-scheduling. SPP will also identify participants that under-schedule "counterflow" – that is, the participant fails to schedule generation at nodes with LMPs higher than the load node (see also discussion on page 2 of Appendix A). In this case, SPP compares the participant's scheduled and actual production with firm load levels. To the extent the participant did not schedule or produce enough, i.e., within 4% of its metered load, from generators located at higher priced nodes compared with its firm load requirement, it would be required to compensate the RTO for a financial amount equivalent to the FTR value from the under-scheduled generator to its load.

[3] In SPP, inter-control area schedules, schedules leaving or entering the SPP footprint, and some intra-control area schedules are "tagged" transactions. Self dispatched resources and schedules leaving or entering the footprint are tagged and sent to the NERC IDC. Tagged schedules sent to the NERC IDC cannot be bid into the market, are not responsive to spot prices, and are thus not available to SPP dispatch. Tagged schedules sent directly to the NERC IDC are, however, subject to spot market financial settlement. Other tagged schedules can be simultaneously bid into the market. If cheaper generation is bid into the market, the scheduled generation can be dispatched at a lower level. The market dispatch is also sent to the NERC IDC and is subject to curtailment. SPP plans to have both schedules (tagged physical schedules and market flow) sent to the NERC IDC for possible curtailment when transmission loading relief is needed. If the NERC IDC identifies market flow needed to produce relief, SPP will identify which internal schedules need to be physically cut (for intra-control area self

process will curtail schedules based on the priority of transmission service for both the physical schedules and financial schedules to ensure that reliable transmission curtailments can be made, that participants do not gain or lose transmission rights from what they had previously under 888 service, and that the scheduling rights (transmission rights) given are feasible when TLRs occur.

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dispatched units) and which schedules should be cut for financial feasibility purposes, based on the schedules priority of service. SPP would cut the physical schedules as directed by NERC.