TENNESSEE REGULATORY AUTHORITY

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460 James Robertson Parkway
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February 18, 2003

VIA ELECTRONIC FILING

The Honorable Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Docket No. RM01-12-000, Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design

Dear Ms. Salas:

For filing, please find the additional Comments of the Tennessee Regulatory Authority in the above-mentioned docket regarding standard market design.

Should you have questions, please feel free to contact Aster Rutibabalira, our primary staff person in the matter, at (615) 741-2904 ext. 150.

Sincerely,

Sara Kyle, Chairman
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	**)**	
Through Open Access Transmission Service	**)**	**Docket No. RM01-12-000**
And Standard Electricity Market Design	**)**	

ADDITIONAL COMMENTS OF TENNESSEE REGULATORY AUTHORITY

EXECUTIVE SUMMARY

The Tennessee Regulatory Authority ("TRA" or the "Authority") offers the following comments in response to the Commission's Standard Market Design Notice Of Public Rulemaking ("*NOPR*") issued July 31, 2002 regarding the following issues: (1) transmission planning and pricing, including Participant Funding; (2) Regional State Advisory Committees and state participation; (3) resource adequacy; and (4) Congestion Revenue Rights (CRRs) and transition issues. The Comments herein are a complement to the Authority's initial comments filed with the Commission on November 14, 2002.

Tennessee is characterized by low-cost power supplied by the Tennessee Valley Authority (TVA)[1]. Electricity markets are not restructured in Tennessee as TVA, municipal utilities and electric cooperatives provide almost 98 percent of electricity to ultimate consumers in Tennessee.

Tennessee is part of the Southeast region and a member of the Southeastern Association of Regulatory Utility Commissioners (SEARUC) and the Southern States Energy Board (SSEB). The comments provided herein represent the views of the Tennessee Regulatory Authority. Although our comments reflect on the regional

1 TVA owns, operates, and maintains 29,469 megawatts of generating capacity and 17,000 miles of transmission line. TVA's major customers are 158 power distributors, mostly municipal-owned companies that purchase wholesale power and distribute it throughout their service areas and 62 directly served customers. TVA, *Annual Report 2000*.

electricity markets in the Southeast, our conclusions and recommendations reflect the concerns of Tennessee consumers.

The Authority makes the following recommendations concerning the issues addressed in these comments:

Transmission planning and pricing: The TRA supports Participant Funding without any attached restrictions and recommends that the Commission's final rule should specify that Participant Funding is FERC's default transmission pricing methodology without any restrictions.

Regional State Advisory Committees (RSACs) and state participation: The Authority believes that a Multi-State Entity (MSE) in the form of a joint board is the most appropriate form of regional entity that the current reform effort should target.

However, if the Commission chooses to use RSACs, the Authority maintains that a single RSAC for siting and other issues, if well designed, will be the most efficient regional entity and recommends that in regions where similar institutions exist, the Commission should allow such institutions to be transformed into RSACs. The final rule should provide for regional flexibility in the design of RSAC and allow each RSAC to devise its own internal organization that fits the region.

Finally, the Authority recommends that each state covered by a RSAC should be represented by the same number of representatives and each state regulatory agency should be represented on the RSAC.

Resource Adequacy: While a fixed minimum reserve requirement of 12 percent may be appropriate in states and regions without retail access, it may not be appropriate in regions with retail access and could lead to a "free ride" problem if implemented.

The final rule should specify an alternative process and default values should be established and applied when all the parties cannot agree on the level of resource adequacy requirement or on the planning horizon.

Finally, the TRA supports the inclusion of liquidated damages contracts for power from unspecified sources in a resource adequacy plan.

Congestion Revenue Rights: The TRA recommends that the Commission remove from the final rule the provision for a four-year transition period and include more regional flexibility in the allocation of CRRs. The Commission should also consider situations where direct allocation of CRRs could be combined with auctions of these CRRs. Further, the final rule should allow those who finance grid expansions to be allocated some of the equivalent financial rights made possible by the grid expansions.

I. TRANSMISSION PRICING

The issue of who pays for transmission investment is very important in the Southeast, where substantial amounts of merchant generation capacity will likely result in power being exported out of the region. If an efficient transmission pricing methodology that is applied consistently by all regions is not adopted, suboptimal siting decisions will be made. The resulting outcome will be market inefficiencies and social inequities between native load customers and those who ultimately will benefit from this new generation.

The *NOPR* proposes recovery of the costs of expansion through Participant Funding, i.e., those who benefit from a particular project (such as a generator to export power or load building to reduce congestion) pay for it. *NOPR* at ¶ 197. The Commission is however seeking comments regarding the *NOPR*'s proposal to consider Participant Funding only if the transmission expansion is proposed by an RTO, ISO, or other independent entity in the context of a regional planning process. *NOPR* at ¶ 199. The Commission concludes that "[i]n the absence of independence, we would apply a

default pricing policy that would recognize the regional benefits of transmission expansion. Under this default policy, we propose to roll-in on a region-wide basis all high voltage network upgrades of 138 kV and above." (*NOPR* at ¶ 200).

The TRA generally supports this cost causation approach and asserts that Participant Funding is the appropriate pricing approach for new transmission and upgrades, regardless of which party planned the construction. Socialization of transmission upgrades and expansion costs (or rolled-in pricing policy) does not send the proper price signals and is not an efficient public policy. Indeed, socialization of transmission costs will shift some or all of the costs of expansion or upgrades to native load consumers who may never benefit from the expansion or upgrades. Efficient and cost-effective investment in transmission is encouraged by pricing upgrades and expansions of the transmission system in an efficient manner, so that transmission prices send proper signals to potential investors.

Although the *NOPR* elaborates significantly on other transmission pricing methodologies, it remains almost silent on how Participant Funding will be implemented. Even though the TRA generally supports Participant Funding, a great deal of detail on its implementation is needed for stakeholders to make informed comments.

The Authority contends that transmission investment needed to maintain the reliability of the existing transmission systems should continue to be recoverable through rolled-in transmission rates charged to all transmission users. All other transmission investments, whether upgrades or expansion, needed to add, integrate, or interconnect new generators to the grid, or to deliver power to a distant location, must be recovered through an appropriately structured Participant Funding that take into consideration all costs and benefits. Such Participant Funding will send an accurate price signal to potential investors and produce retail prices that promote equity among all customers.

The Authority is encouraged by the Commission's approval of Participant Funding in the SeTrans RTO as part of a general framework.[2] However, the TRA supports Participant Funding without any attached restrictions and maintains that, if the Commission thinks that Participant Funding is the most efficient and cost-effective transmission pricing policy, then the Commission's final rule should specify that Participant Funding is FERC's default transmission pricing methodology without any restrictions. Thus, the Authority requests that the restrictions imposed by the *NOPR* on Participant Funding be lifted.

II. Regional State Advisory Committees

The Commission seeks comments on whether there should be a single RSAC or separate committees for siting and other issues. It also seeks comments on how the state representatives should be selected (e.g., whether the governor should select them or some other process should be used). *NOPR* at ¶ 553.

The *NOPR* proposes a formal role for states, with each independent transmission provider (ITP) having a relationship with an RSAC that would share the oversight of the ITP with the Commission. As cited in the *NOPR*, the National Governors' Association (NGA), in a recent report entitled "Interstate Strategies for Transmission Planning," recommended establishing "multi-state entities" to facilitate state coordination of transmission planning, certification and siting at the regional level. *NOPR* at ¶ 552. RSACs will follow this proposed model, but will also have responsibilities for market power monitoring and mitigation, resource adequacy and setting a region's minimum level for reserves and planning horizon. *NOPR* at ¶ 552.

Although the *NOPR* proposes one major decision-making function for the RSACs, that is, setting the minimum level of resource adequacy for the region, the role specified for RSACs is advisory in all other aspects. As proposed by the NGA a MSE

2 Order Granting Petition for Declaratory Order, at ¶ 132, Docket No. EL02-101-000, October 10, 2002.

would actually play a more meaningful role by providing regulatory oversight on a regional basis on many issues of interest to states.

The objectives of the regional MSE are: (1) to facilitate a strong state role in RTO, (2) to have a collective voice on issues critical to states such as cost allocation and market design, (3) to coordinate multi-state review and permitting for proposed interstate transmission projects, and (4) to allow states to formulate their own solutions to regional transmission issues.[3]

The Southern States Energy Board expressed its desire to be recognized as the appropriate regional organization to begin facilitating state coordination on these issues.[4]

The TRA considers a joint board the most appropriate form of MSE that the current reform effort should target. Only the joint board was mandated by Congress in Section 209 of the Federal Power Act (FPA),[5] which authorizes the Commission to convene joint boards with state PUCs. A joint board is likely to make recommendations acceptable to all stakeholders, including the Commission and the RTOs. A joint board, with adequate state representation, is the best approach to ensure that regional differences are taken into consideration when fulfilling the requirements of the SMD rule.

While the idea of creating RSACs may address many of the states' concerns, there are a number of issues that have not been addressed by the *NOPR*. The TRA has many questions, including which state entities are included in the RSAC (i.e., governor's appointee, public utility commissioners, state department of energy or department of economic development, etc.), what should be the geographic scope of the RSAC, and

3 Southern States Energy Board, Memorandum, October 30, 2002.
4 Id.
5 16 U.S.C. 824h (1988)

whether states neighboring an RTO or an ITP should have representatives on the RSAC. These are but a few among many questions that the *NOPR* did not address, and they are key to whether or not a stakeholder supports state and federal cooperation. The TRA recommends that the Commission analyze and contrast both the Joint Board and RSACs before making a final decision on what form of state participation to include.

The Authority is concerned that even before the RSACs are formed, the list of tasks that they are required to accomplish is daunting and could lead to their lack of success. Indeed, the *NOPR* gives RSACs many tasks that often require their collaboration with other entities. Those tasks include but are not limited to:

- guidance to ITP in establishing regional reserve margin and defining a forward planning horizon (*NOPR* at ¶ 487 to ¶ 493, ¶ 524),
- identifying the beneficiaries of a proposed expansion and how costs for that expansion should be recovered (*NOPR* at ¶ 166),
- facilitating the siting of regional expansions, make recommendations on pricing proposals (*NOPR* at ¶ 201),
- playing an active role in establishing rate design for new ITP and in converting the rights of existing customers to CRRs or auction revenues under the new tariff (*NOPR* at ¶ 371),
- facilitating state coordination on transmission planning, certification, and siting at a regional level (*NOPR* at ¶ 553),
- and seeking regional solutions to issues that may fall under federal, state, or shared jurisdiction (*NOPR* at ¶554).

Additionally, there are political challenges in creating the necessary regional institutions and the public process through which decisions will be made and validated. Also of concern is the fact that a fully functioning RSAC would take years to materialize. Lastly, it is not clear how the RSACs will fulfill its functions.

Despite these concerns, instead of multiple advisory committees, the Authority asserts that a single RSAC for siting and other issues, if well designed, will be the most efficient regional entity. In regions where similar institutions exist, the Commission should allow such institutions to be transformed into RSACs. The final rule should provide for regional flexibility in the design of RSAC. Also, the Commission should permit each RSAC to devise its own internal organization that fits the region with the qualification that each state covered by a RSAC should be represented by the same number of representatives on the RSAC and each state regulatory agency should be represented on the RSAC.

Finally, the Authority recommends that each state covered by a RSAC should be represented by the same number of representatives and each state regulatory agency should be represented on the RSAC.

III. RESOURCE ADEQUACY

The NOPR proposes to adopt a 12 percent reserve margin as a minimum regional reserve margin for all regions. *NOPR* at ¶ 493. The *NOPR* proposes however that within each region, an RSAC would define acceptable resource adequacy (or reserve margin) targets, subject to a minimum reserve margin of 12 % set by the Commission. *NOPR* at ¶ 490. In addition, the Commission seeks comments on whether liquidated damages contracts for power from unspecified sources should be included in a resource adequacy plan. *NOPR* at ¶ 513.

The Authority commends the Commission for the approach presented in the *NOPR* to ensure long-term resource adequacy. The Commission believes that each region must take its own generation and load characteristics into account when determining the appropriate reserve level, and that close coordination between generation and transmission planning is necessary. *NOPR* at ¶¶ 488-490. We agree with the Commission that adequacy must be addressed at the regional level. As mentioned in our previous comments, the Authority supports a regional approach to deal with most problems included in the *NOPR*.

The Authority contends that the adequacy and reliability of electricity systems are very important aspects of any standard market design. We support the Commission's provision for a long-term adequacy planning horizon, as well as its requirement that the ITP develop a load forecast to cover that period. However, we do not support a required minimum reserve level, such as the 12% suggested in the *NOPR*. A fixed minimum reserve requirement may not be appropriate in all situations and is not flexible enough to assure resource adequacy in all circumstances.

Although the Commission is rightly concerned that without the adequacy requirement there would be a "free rider" problem (*NOPR* at ¶¶ 460-473), the proposed solution may actually exacerbate the problem. Because the proposed minimum 12 % reserve requirement applies to the ITP's system as a whole, some Load Serving Entities (LSEs) will have more than 12% while others will "free ride" the system with less than a 12% reserve margin. This scenario could create a problem for the entire system if most LSEs are induced to take advantage of the weakness of the system.

In addition, the *NOPR* requires all LSEs to develop a plan to meet their shares of the reliability requirement three years hence. We argue that this requirement may not always work. In regions without retail competition, in which a single utility is responsible for meeting all future load requirements and has not joined an RTO, this provider would take over the long-term resource adequacy planning functions. In regions with retail competition, free entry and exit of competing firms may make it impossible to develop efficient long-term resource adequacy plans. Indeed, because consumers are allowed to switch from one LSE to another or to move between regulated default suppliers and competitive LSEs on short notice, it would be impossible for the ITP or RTO to allocate resource acquisition responsibilities years in advance to each LSE. Neither the ITP, RTO nor LSE could know individual LSE loads more than a month in advance. In this instance, the Commission should include in the final rule procedures or guidelines that would require an ITP to ensure resource adequacy in the region. The final rule should include details of what market-based processes an ITC should use to meet the

minimum reserve requirement and state that the cost of meeting this reliability requirement should be shared by all electricity consumers in the region.

Further, the *NOPR* provides that within each region, an RSAC would define acceptable resource adequacy (or reserve margin) targets, subject to a minimum reserve margin of 12 % set by the Commission. *NOPR* at ¶ 490. While this provision proves that the Commission has good intentions to involve states in the resource adequacy planning functions, it may not work in practice. This presupposes that all parties involved – ITPs, LSEs, State regulators, FERC and the RSAC – will reach a unanimous agreement. Because it is likely that all parties involved will not reach a consensus, the final rule should specify an alternative process and default values should be established and applied when all the parties cannot agree on the level of resource adequacy requirement or on the planning horizon.

Concerning liquidated damages contracts for power from unspecified sources, the TRA contends that, since a contract for development of new resources would include penalties for non-performance, a contract for supply from unspecified sources should include provisions for liquidated damages for non-performance. Accepting the use of firm liquidated damages contracts will encourage long-term bilateral contracts, better management of participant risks, and discourage incentives to game the system. In addition, the possible prohibition against the use of liquidated damages contracts as a reliability resource is inconsistent with the *NOPR*, which uses financial instruments to reach targeted results.

The Authority is concerned that the *NOPR* gives the ITPs the latitude to implement regional resource adequacy requirements with penalties for non-compliance regardless of whether or not the utilities in question are exempt from the Commission's jurisdiction. Given that electricity landscape of Tennessee is dominated by TVA, municipal utilities and cooperatives, which are all exempt from the Commission's regulation, the Authority recommends that the final rule clarify the division of resource

adequacy responsibilities between ITPs and those utilities exempt from the Commission's regulation.

IV. CONGESTION REVENUE RIGHTS AND TRANSITION ISSUES

The *NOPR* proposes to establish a congestion management system using locational marginal pricing (LMP) and CRRs. *NOPR* at ¶ 203. The *NOPR* proposes that "rather than using a system of physical reservations, a system of financial rights called Congestion Revenue Rights will be used to give customers the ability to protect themselves against congestion costs." *NOPR* at ¶ 235. The Authority addresses the following issues of interest: (1) the transition period, (2) the allocation of CRRs during and after the transition period, (3) load growth, and (4) CRRs for transmission upgrades.

This *NOPR* establishes a preference for the auction of CRRs. This means that ratepayers who paid for a particular transmission system would not have guaranteed access to that system. The *NOPR* offers little protection for existing transmission rights, including rights to serve native load growth or to change pre-schedules and points of delivery without penalty.

The length of the transition period

The Commission seeks comments on whether to allow a transition period before the start of Congestion Revenue Rights auction allocations and, if so, what the length of such a transition should be. *NOPR* at ¶ 382.

The *NOPR* proposes a four-year transition period during which regional flexibility on this issue will be allowed. Specifically, during the transition period, after consultation with the RSAC and stakeholders in a region, the ITP could decide to directly assign CRRs. After the four-year transition, the Commission calls for all transmission rights to be put up for auction. This would force small rural utilities to compete with deep-pocketed marketers and financial institutions for the transmission capacity the utilities

need to keep on their customers' lights. The Commission actually states that the goal is to ensure that "customers that value the transmission the most will get it." *NOPR* at ¶¶140, 210. In other words, the goal is to ensure that those who can afford to drive up the price of transmission the highest will get to move power. The Commission does not even require those bidding to have any intention of delivering power. The *NOPR* states: "Once a customer has these point-specific Congestion Revenue Rights, the customer may sell them at any time to another entity, whether or not that entity intends to transmit power. The sale could be for all or a portion of the amount or duration of the Congestion Revenue Rights." *NOPR* at ¶ 162.

Because in states and regions without retail access, limiting the transition period to four years does not provide adequate protection to native load customers, the Authority supports a longer transition period during which regional flexibility on this issue will be allowed. The Authority recommends that the Commission remove from the rule the provision for a four-year transition period and include in the final rule more regional flexibility in the length of the transition period.

Allocation of CRRs

The *NOPR* proposes an initial allocation of all CRRs during the transition period and an overall preference for an auction of all CRRs thereafter. The Authority supports the initial allocation of CRRs to existing long-term customers because they will face increased risks due to congestion costs. However, in states and regions without retail access, limiting the transition period to four years does not provide adequate protection to native load customers, and auctioning CRRs after the transition period would harm native load customers and interfere with the obligations of load serving entities to serve native load in accordance with the requirements of state laws. The Authority anticipates that, in states with retail access, auctioning CRRs will result in a more dynamic secondary market. However, states and regions without retail access should be allowed flexibility such that regional entities like the RSACs and ITP/RTOs could determine when all the necessary conditions are met to move from direct assignment to auction of the CRRs.

Regional flexibility will provide greater protection to native load customers and allow a smooth transition to market conditions for CRRs. Therefore, the Authority recommends that the Commission clarify in the final rule that it will allow regional flexibility regarding the direct allocation of CRRs and the length of the transition period.

Load growth and direct allocation of CRRs

The *NOPR* also states that existing customers would not be granted an initial allocation based on additions for future load growth, but would have to secure those rights in the market. The Commission seeks comments as to whether and under what circumstances load growth should be accommodated in the direct allocation of CRRs. *NOPR* at ¶ 376. The Authority contends that as long as the long-term planning horizon of an LSE includes native load growth, forcing existing customers to secure CRRs from the market will impose additional costs that would not have existed in the absence of a standard market design.

The Commission should clarify that after the transition period, any additional CRRs needed to serve load growth will be allocated to LSEs and existing long-term customers to meet native load growth. Indeed, in regions without retail access, LSEs will be exposed to the congestion costs associated with serving the physical load it has the obligation to serve, and its existing customers will be exposed to similar risks. Therefore, as long as a region has not moved to retail access, the allocation of CRRs on an annual basis to existing customers and LSEs should continue until a competitive retail market is in place. Thus, the Authority recommends that the Commission include in the final SMD rule more regional flexibility in the allocation of CRRs. The Commission should also consider situations where direct allocation of CRRs could be combined with auctions of these CRRs. In this case, the Commission should anticipate negotiated multiparty agreements.

Allowing credits for upgrades

The *NOPR* proposes that "[i]f an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled in, the entity would receive Congestion Revenue Rights associated with the new transfer capability. In the past the Commission has allowed credits for upgrades; is there still a role for credits under Standard Market Design?" *NOPR* at ¶ 238. The Authority believes that the final rule should clarify how to allocate rights to the existing grid and rights to grid expansion. It should allow those who finance grid expansions to be allocated some of the equivalent financial rights made possible by the grid expansions. The Authority supports the idea that those who pay for grid upgrades and expansions should receive any resulting economic value. Those CRRs entitle the customer who paid for upgrades to the revenue stream to be associated with any future congestion on the facilities they financed. However, we continue to maintain that the Commission should allow regional flexibility in the way benefits will be matched with costs, so that distribution of duplicative credits will be avoided. The *NOPR* proposes that "[t]he initial allocation process for Congestion Revenue Rights will be done through compliance filings that allow for different treatment within each region." *NOPR* at ¶ 236. However, the Commission fails to provide this regional flexibility after the transition period.

CONCLUSION

The Tennessee Regulatory Authority respectfully asks that the Commission take action consistent with the comments provided herein.

Respectfully submitted,

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