

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Accounting and Financial Reporting for
Public Utilities

Docket No. RM04-12-000

**COMMENTS OF
TRANSMISSION ACCESS POLICY STUDY GROUP**

Pursuant to the Commission's June 2, 2005 Notice of Proposed Rulemaking, 111 F.E.R.C. ¶ 61,352 (June 2, 2005) ("NOPR"), as published in the Federal Register, 70 Fed. Reg. 36865 (June 27, 2005), the Transmission Access Policy Study Group ("TAPS") submits these comments. Part I below addresses the steps needed to make the direct and indirect costs of RTOs more transparent and controllable — and to do so without enabling vertically integrated utilities to bury their market participation costs in nominally transmission-related accounts that flow through regulated rates to their competitors. Part II addresses further steps needed to "provide greater transparency by public utility transmission owners for the revenues received for use of their transmission facilities," a goal that the NOPR (at P 74) rightly embraces, but does too little to advance.

**I. ACCOUNTING FOR AND CONTROLLING COSTS INCURRED BY OR
DUE TO RTOS**

On November 9, 2004, TAPS submitted comments¹ on the Commission's RTO accountability Notice of Inquiry.² In those comments (at 3-4), TAPS warned that the RTO cost explosion threatens to turn the efficiency-motivated policy contemplated by Order 2000, and

¹ See Comments of the Transmission Access Policy Study Group, filed on November 9, 2004 in this proceeding, available at <http://elibrary-backup.ferc.gov/idmws/common/OpenNat.asp?fileID=10288194>.

² September 16, 2004 Notice of Inquiry, "Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators," 108 F.E.R.C. ¶ 61,237

supported by TAPS, into an albatross consumers in RTO regions are required to bear. Those comments (at 2) describe how RTO administrative costs are imposing substantial burdens on TAPS members, exceeding the total power supply staffing, operations and planning budget of one TAPS member, and exceeding another TAPS member's cost to operate its own 24-hour, 365-day-a-year energy control center to dispatch approximately 5.5 million MWh of power to its municipal members.

More recently, one TAPS member (Wisconsin Public Power Inc.) has calculated that MISO's market-related administrative charges and uplift costs have increased its total power supply bill to its municipal members by 2-3% for the first four months of MISO's Day 2 market operations. For another TAPS member (Missouri River Energy Services), MISO's market-related administrative and uplift costs during the same period increased the total cost of MRES-supplied power to its municipal member loads in the MISO footprint by more than a 4%. Nor is this experience limited to MISO. Vermont Public Power Supply Authority, which represents approximately ½% of the New England load, has calculated that its share of ISO-NE's 2005 budget for operating expenses, debt service, and depreciation amounts to more than twice the cost of VPPSA's Power Supply Department,³ and represents a nearly 900% increase over VPPSA's share of NEPOOL's cost to operate a centrally dispatched pool.⁴

(2004), published 69 Fed. Reg. 58,112 (September 29, 2004).

³ It is also significant that on average, 40% of the VPPSA Power Supply Department staff time is dedicated to managing interactions with ISO-NE and its markets.

⁴ Prior to ISO-NE, VPPSA members paid their share of New England Power Pool's operating cost to dispatch all available units on a least-cost basis. NEPOOL's operating costs were on the order of \$14 million annually, of which VPPSA's share would have been some \$70,000. ISO-NE 2005 budget for operating expenses, debt service, and depreciation is \$125,000,000, which adds \$625,000 to VPPSA's cost of serving its member systems. These estimates of VPPSA's share is based on its percentage of New England load (*i.e.*, approximately ½%); exact tracking of the allocation of ISO-NE operating costs is very difficult.

Thus, today there is even more reason to reiterate our November request that the Commission promptly put RTOs on a pro-consumer track of cost containment and efficient operation that is accountable to the customers that pay the costs incurred and caused by the RTO, by adopting the following steps:

- ❑ Revising the Uniform System of Accounts to better capture RTO functions and associated costs, and requiring the RTO to report estimated RTO-caused costs incurred by market participants as well.
- ❑ Modifying RTO governance to provide for hybrid boards, with a balanced stakeholder minority, to better instill accountability and to make the board less isolated and less captive to management.
- ❑ Making the process for election of independent board members more robust, and eliminating self-perpetuating boards.
- ❑ Putting in place cost control measures, including:
 - an independent, biennial study of all U.S. RTOs that benchmarks each RTO's operating costs, as well as the costs of particular RTO functions, against the costs of other RTOs (here and elsewhere) and, where possible, against the costs of non-RTO transmission providers and non-RTO operators of comparable markets;
 - independent, biennial, cost-benefit analyses (with results shown by state) and RTO efficiency audits;
 - assessment of the cost/benefits of new initiatives or major rule changes before undertaking them, taking into account both RTO costs and costs to market participants (and thus end users), with a true-up of the study to actual costs if the initiative/rule change is ultimately undertaken;
 - annual public reporting of various RTO performance measurements, including congestion costs, interconnection and service queue status, reliability/outage statistics; and progress on meeting planning and expansion targets; and
 - advance stakeholder review of each RTO's annual budget, with a specific allowance for stakeholder rejection or modification of the budget where a substantial majority of stakeholder sectors agrees, as well as allowance for the RTO board, if it believes that a modified budget jeopardizes its ability to meet its obligations, to appeal to the Commission with sufficient time and factual support to permit the Commission to resolve the issue *before* the budget takes effect.
- ❑ Tying RTO senior management compensation to specific performance measurements, including independent measures of customer satisfaction; reductions in costs of congestion; RTO cost containment; reduction in

interconnection and transmission queues; meeting aggressive planning and construction goals; and other objective measures of high quality RTO service.

In its NOPR, the Commission sought to address some aspects of the first item identified above—revising the Uniform System of Accounts (“USofA”) to better capture RTO functions and costs. It looks to TAPS like the Commission is generally on the right track and, as to specific comments on this effort, TAPS generally supports the comments filed this day by the American Public Power Association.

The NOPR also makes strides on collecting the costs incurred by jurisdictional transmission owners (“TOs”) to subject their facilities to RTO control. However, in doing so, the Commission must make a distinction between the costs vertically-integrated TOs incur as TOs and costs they incur as RTO market participants or as generators. The latter types of costs are also borne individually by other market participants, including transmission-dependent systems, and must separately be accounted for in a manner that makes such costs transparent and avoids the potential for subsidization of the market-related costs of one group of market participants (TOs) by others.

For example, new proposed Account 561.5, long-term reliability, planning and standards development, appears to cover both RTOs and TOs. *See* NOPR at PP 61-62. While TAPS has no problem with the proposal to capture RTO resource planning and resource adequacy in Account 561.5, inclusion of vertically-integrated TOs’ expenses for “resource planning to develop long-term strategies to meet customer demand and energy requirements” as a transmission expense would result in forced subsidization of the TOs’ generation function by competitors. Transmission customers, who incur their own expenses for “resource planning to develop long-term strategies to meet customer demand and energy requirements” would bear

their own costs, plus a share of the TOs' costs for comparable activities.⁵ Thus, to the extent vertically-integrated TOs can use the new accounts to classify their activities as transmission expenses, the Commission needs to ensure that TOs' generation function expenses are not included.

Further, the Commission's accounting efforts still omit much of the RTO cost picture. A complete assessment of RTO costs requires examination of not only the costs incurred by RTOs, but also the costs *caused by* RTOs. Without the reporting of such costs, RTOs can mask the true costs of their operations by pushing costs off their own books and onto those of market participants. To recognize and hold RTOs accountable for such costs, the Commission should require the RTO to report on estimated costs incurred by market participants to participate in the market and comply with RTO rules, including costs incurred to participate in RTO stakeholder processes. Collection of this information through the RTO makes good sense given the wide range of market participants (encompassing small non-jurisdictional utilities and arbitrageurs) and the need for standardization. At minimum, the RTO should at least be required to estimate the burdens imposed on market participants, subject to comments, in a manner analogous to the

⁵ Similarly, inclusion of all vertically-integrated TOs' costs for developing reliability standards (proposed Account 561.5, Item 9), if allowed to be collected in transmission rates, would require competitors to fund vertically-integrated TOs' participation in NERC's process for developing mandatory reliability standards for planning and operation of the bulk power system, which includes "electric energy from generation facilities needed to maintain transmission system reliability." See FPA § 215(a)(1)(B) as added by §1211 of the Energy Policy Act of 2005, H.R. 6, 109th Cong. (H. Rept. 109-190), which was signed into law on August 8, 2005. While it may not be easy to draw a line distinguishing TOs' interests in the NERC process as transmission owners from their interests as generators, that distinction must be made if the Commission is to achieve just, reasonable and not unduly discriminatory transmission rates, promote competitive markets, encourage divestiture to independent transmission companies, and avoid stacking the deck in the NERC standard development process. (Segregating balancing authority-related costs is similarly important to avoid creation of unnecessary barriers to control area consolidation.) The only alternatives consistent with comparability principles would be to (1) place these costs into an account clearly not yet associated with either function, to be allocated or otherwise divided when considered for rate purposes, or (2) declare that NERC-related costs are transmission costs for all participants, and to allow TDUs and others who incur these same costs to include them in the RTO ATRR on a comparable basis.

Commission's obligations to the Office of Management and Budget under Section 3507(d) of the Paperwork Reduction Act of 1995.⁶

More fundamentally, TAPS stresses that the NOPR is just step one and, if the Commission is serious about getting a handle on RTO costs it must promptly implement additional actions, including those listed above and described in more detail in our November 9 Comments. While all these measures are important, plainly reformed governance and focused incentive compensation for senior management are absolutely critical to changing RTOs into customer- and cost-conscious entities.

II. TRANSPARENT ACCOUNTING FOR TRANSMISSION REVENUES

While helpful, the NOPR's proposal to break out from the general revenue account (No. 456) a new sub-account number 456.1 for "Revenues from transmission of electricity of others," and thereby distinguish the "revenues the public utility receives for the transmission of electricity over its transmission facilities," still provides for far too little transparency regarding the particular sources of those revenues and how they relate to common ratemaking categories. Truly transparent accounting for transmission revenues would enable customers and the Commission to monitor whether previously accepted rates have come to generate more than the appropriate level of revenues, and to allow for restoration of appropriate revenues through a Section 206 proceeding as necessary. But the reality is that such Section 206 cost investigations are rare, because a lack of transparency places unnecessary and impeding uncertainties in the way of anyone who attempts to ascertain, from publicly available Form 1 accounting information, what unit transmission cost the Commission would find were it to apply its standard ratemaking policies to the transmission owner's current costs and loads. By the same token,

⁶ 44 U.S.C. § 3507(a)(1)(D)(5).

formula rates that draw on Form 1 information commonly have to massage the Form 1 data, through adjustments that are not always consistent and transparent, to ready it for ratemaking application. Modernized accounting would provide accounting data ready for direct ratemaking use.

The main impediments to such transparency are unnecessary and easily remedied. Without attempting to be comprehensive, we submit the following as examples of how accounting and its reporting have failed to keep pace with standard ratemaking practice, and as to which public utilities now have widely varying practices that impede monitoring and should be standardized.

- Account 456 information should be broken down sufficiently to allow ready computation of the revenue that would be deemed revenue-creditable under generally applicable Commission policy. Breaking out transmission access charge revenues (from other functions' revenues, such as ancillary services, and from tax and FERC assessment revenues) is a good start, and the Commission should make clear that the new Account No. 456.1 should provide that break-out. But further sub-categorization is needed. Account 456.1 revenues should be broken down into the various firmness and duration classes of OATT and grandfathered agreements (so as to allow ready determination of which revenues should be credited, as distinguished from having the associated loads included in rate divisors), and presented separately. Revenues from "wholesale distribution" (transmission for non-end-users, over facilities classified as distribution for accounting purposes) should likewise be separately identified. So should revenues received pursuant to Financial Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), and similar instruments.
- The standard rate divisor as specified in Order 888 — peak load adjusted by removing point-to-point deliveries' scheduled loads and substituting their reserved capacities — is not reported in Forms 1. Instead, those seeking to compare transmission owners' revenues, rates, and costs at best must painstakingly reconstruct one using 12 CP information and guesswork, and often will find that critical information is not available. The divisor should be reported in the Form 1, with separate identification of any behind-the-meter loads that counted towards network service billing determinants and of the relevant point-to-point loads and reserved capacities. Where the principal rate through with the transmission owner's transmission investment is recovered uses a different billing determinant (*e.g.*, the modified 1 CP based on five peak hours used for network service billing in much of PJM), the Form 1 should report that divisor as well.

- ❑ The plant, depreciation, and expenses associated with facilities that have been accounted for as transmission but are either functionalized to other functions or directly assigned (such as generator step-up transformers) are not all separately identified. They should be.
- ❑ The existing Form 1 reporting of individual line and substation facilities should be expanded to identify which facilities have been placed under operation or control of another entity (such as an RTO or ITC), and the gross plant investment of each facility so transferred.
- ❑ Where the transmission owner is participating in a regional transmission entity, revenue distributions received from that regional entity should be reported, with breakdowns showing, e.g., operating fees or leases for transferred facilities, distribution of revenues from zonal transmission charges, pass-through of revenues for ancillary services and wholesale distribution services, reimbursement of start-up costs, distribution of revenues from third-party (out and through) transactions, and distribution of FTR or ARR revenues.

With today's computerized accounting systems and electronic reporting, maintenance and reporting of such information would not be unduly burdensome. The Commission should attend to this subject now, so that utilities can make the necessary changes to their accounting systems and practices as they comply with the rest of the final rule.

Respectfully submitted,

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