

Act, or DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979).

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Withdrawal

Accordingly, the notice of proposed rulemaking, Docket 2002–NM–257–AD, published in the **Federal Register** on June 18, 2004 (69 FR 34096), is withdrawn.

Issued in Renton, Washington, on September 20, 2004.

Kalene C. Yanamura,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–21817 Filed 9–28–04; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35, 41, 101, 141

[Docket No. RM04–12–000]

Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators

September 16, 2004.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of inquiry.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is inviting comments on its accounting and financial reporting requirements for and oversight of regional transmission organization (RTO) and independent system operator (ISO) costs.

DATES: Comments on this NOI are due on November 4, 2004.

ADDRESSES: Comments may be filed electronically via the eFiling link on the Commission's Web site at <http://www.ferc.gov>. Commentors unable to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE., Washington, DC 20426. Refer to the Procedure for Comments section of the preamble for additional information on how to file comments.

FOR FURTHER INFORMATION CONTACT: Mark Hegerle (Technical Information), Office of Markets, Tariffs & Rates—Central, Federal Energy Regulatory

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SUPPLEMENTARY INFORMATION:

Notice of Inquiry

Introduction

1. The Federal Energy Regulatory Commission (Commission) is issuing this Notice of Inquiry to seek comments on its accounting and financial reporting requirements for and oversight of regional transmission organization (RTO) and independent system operator (ISO) costs. Specifically, the Commission is undertaking a review of:

(a) Whether changes are needed to the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (USofA), (18 CFR part 101), to better account and report RTO and ISO financial information to the Commission, in order to provide greater transparency of transactions and business functions affecting these entities and their member transmission-owning public utilities;

(b) Whether RTOs and ISOs have appropriate incentives to be cost efficient; and

(c) Whether the Commission's rate review methods for RTOs and ISOs are sufficient.

Background

2. In Order No. 888,¹ the Commission encouraged but did not require the formation of ISOs—-independent entities that administer regional transmission tariffs and control the transmission facilities of their member transmission-owning utilities. Rather, Order No. 888 delineated eleven principles defining the operations and structure of a properly functioning ISO. Likewise, in

Order No. 2000,² the Commission encouraged utilities to voluntarily join RTOs, and detailed certain functions an RTO must perform and characteristics that an RTO should have.³ However, in neither rule did the Commission promulgate specific accounting rules or rate review principles for the new entities. The Commission instead chose to rely on existing rules and policies applicable to traditional public utilities, *i.e.*, principally investor-owned utilities (IOUs).

3. Over the past seven years, beginning in 1997, the Commission issued a series of orders approving several ISOs and RTOs which have since commenced operations. PJM Interconnection, LLC (PJM), ISO New England, Inc. (ISO-NE), and Midwest Independent Transmission System Operator, Inc. (Midwest ISO) were first approved (or conditionally approved) as ISOs and later as RTOs; New York Independent System Operator, Inc. (NYISO) and California Independent System Operator, Inc. (CAISO) were approved as ISOs. The Commission has also conditionally approved Southwest Power Pool, Inc. (SPP), which currently operates a regional transmission tariff, as an RTO. The Commission also conditionally approved a number of other RTOs and ISOs which have not commenced operations.⁴

4. Each of these entities developed independent of one another, using somewhat different business models, software, accounting methods, and rate designs to accomplish the same ultimate goal of providing open-access (non-discriminatory) regional transmission service. In addition, some of these entities administer centrally-dispatched, competitive energy markets. These differences have made comparisons between entities difficult and raised questions concerning the Commission's current accounting and financial reporting rules and our current rate review practices for RTOs and ISOs.

5. Nevertheless there are similarities among RTOs and ISOs as well. Each RTO/ISO administers a regional transmission tariff and performs system monitoring and planning, as well as

¹ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888–A, 62 FR 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Policy Study Group, *et al.* v. 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002).

² Regional Transmission Organizations, Order No. 2000, 65 FR 809 (January 6, 2000), FERC Stats. & Regs., ¶ 31,089 (1999), *order on reh'g*, Order No. 2000–A, 65 FR 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *affirmed sub nom.* Public Utility District No. 1 of Snohomish County, Washington, *et al.* v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

³ ISOs and RTOs are, in many respects, similar, with one major difference being that RTOs must meet more stringent independence and scope and configuration standards.

⁴ RTO West (now Grid West), WestConnect, GridFlorida, GridSouth, and SeTrans.

transmission scheduling—functions that formerly were performed by the transmission-owning utilities that now take transmission service under the RTO's or ISO's tariff. While there may be some needed redundancy with respect to certain functions, such as system reliability monitoring, because an RTO/ISO, with its regional focus and reach, takes over certain functions previously performed by the transmission-owning public utilities, ratepayers should, over time, expect to see economic synergies resulting from the formation of RTOs.⁵

Differences Between RTOs and Investor-Owned Utilities

6. There are several significant differences between RTOs/ISOs and vertically integrated public utilities. As noted above, each RTO/ISO offers transmission service over a wide region of the country, covering multiple IOU and other transmission systems. Many also run energy markets and congestion management systems through central dispatch of the generation located in their footprint. However, unlike IOUs, RTOs and ISOs do not own the transmission and generation facilities under their control. In fact, they are required to be independent from any market participant.⁶

7. RTO and ISO costs are largely associated with sophisticated system control and communications hardware and software designed to oversee the transmission grid, and, for many, to run energy markets, congestion management systems, and transmission scheduling systems. In contrast, an IOU's costs are dominated by the costs of generation, transmission, and distribution facilities.

8. In addition, because RTOs/ISOs provide transmission service and may operate wholesale markets, they do not provide retail electric service, and, therefore, fall under the exclusive jurisdiction of the Commission. This means that RTOs and ISOs, unlike vertically integrated IOUs, are not subject to direct oversight by state commissions.

9. Moreover, while the Commission has not mandated any particular

business model for RTOs and ISOs, all current RTOs and ISOs are not-for-profit entities.⁷ Each RTO and ISO is required to have an independent board of directors and to consult with an advisory committee made up of all classes of market participants prior to taking action. However, the advisory committee has no ability to block an action of the RTO/ISO; it can only offer non-binding advice on budget and other matters. Moreover, with for-profit entities, shareholders face a risk of lower earnings if costs are found to be imprudent and ineligible for rate recovery. The not-for-profit status of RTOs/ISOs makes cost review more difficult. As the Commission has previously observed, with respect to one of these RTOs, "Midwest ISO's non-profit status complicates a prudence review after the costs are incurred."⁸

Current RTO Accounting, Financial Reporting and Cost Recovery Practices

10. Despite their differences, RTOs/ISOs are public utilities under the Federal Power Act and, like traditional public utilities, must follow the USofA.⁹ However, the USofA was developed for traditional public utilities, *i.e.*, public utilities that provide electric generation, transmission, and distribution service. The accounting rules contained in the USofA provide for capturing financial information along these primary functional business lines.¹⁰ However, meaningful functional business segments or service lines for RTOs and ISOs seem quite different. Meaningful business lines for RTOs might include "grid reliability," "ancillary services," or "energy markets," to suggest a few possibilities. But because RTOs use the Commission's existing USofA to capture and classify costs, their financial statements and other reports prepared from their accounting records may not provide sufficient information about their costs and the relationship to services provided or other business activities.

11. Likewise, the current USofA may not provide sufficient transparency with respect to changes in RTO- and ISO-

member transmission-owning public utilities' costs to reflect that the RTO/ISO is performing all or a portion of certain functions that were previously performed by the transmission-owning utilities.

12. Differences also exist among RTOs/ISOs with respect to operations, rate design, and accepted rate review methodologies. For example, RTOs/ISOs, while progressing at differing paces, perform similar functions with respect to overseeing the transmission grid and running markets. However, rather than building on the work of others, each RTO/ISO has developed, or contracted with vendors to develop, proprietary software to run its complex systems. The cost of each RTO's/ISO's software package, while largely designed to do similar tasks, varied considerably.

13. With respect to rate design differences, as an example, NYISO has just one charge to recover all of its costs to administer its transmission tariff, energy markets, and congestion management system, including its auction of transmission congestion contracts (comparable to firm transmission rights (FTRs)).¹¹ However, ISO-NE and Midwest ISO have three charges, PJM five, and CAISO seven to recover comparable costs. Some use formula rates with true-ups; others calculate stated rates for the following calendar year. There are also differences among the RTOs/ISOs with respect to the billing determinants used to calculate similar charges.

14. RTOs/ISOs develop their proposed rates through a collaborative process with their respective advisory committee processes. In general, the RTO/ISO determines the cost side of the equation based on the level of expenditures budgeted to accomplish the RTO's/ISO's functions,¹² and works with its stakeholders through the advisory committee process to arrive at a proposed allocation methodology, which is filed with the Commission (under section 205 of the FPA).¹³ The Commission has largely relied on each advisory committee process as a check on RTO expenditures and has focused primarily on the review of the cost allocation and rate design methodologies. In addition, the Commission required one RTO,

⁵ For example, Order No. 2000 noted one entity's observation that there may be transmission functions performed by individual company control centers, within existing control areas, or within existing reliability councils, that may be better and/or more efficiently performed by an RTO.

⁶ A market participant is defined in relevant part as any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the RTO or any other entity (*e.g.*, a member transmission-owning utility), which has economic or commercial interests that would be significantly affected by the RTO's actions or decisions. See 18 CFR 35.34(b)(2) (2004).

⁷ One exception is that PJM earns money for its members when it sells software and technology to other transmission providers. Nevertheless, like the other RTOs, PJM does not have shareholders and passes through all of its costs of operation to its market participants.

⁸ Midwest Independent Transmission System Operator, 101 FERC ¶ 61,221 at P 35 (2002), *order on reh'g*, 103 FERC ¶ 61,035 (2003).

⁹ See 18 CFR Part 101.

¹⁰ The Commission has explained that RTOs and ISOs are public utilities, and as such, they are required to follow the USofA and file Form No. 1. See PJM Interconnection, L.L.C. *et al.*, 107 FERC ¶ 61,087 (2004).

¹¹ NYISO also has separate charges for unbudgeted costs, and start-up and formation costs.

¹² The costs incurred by the RTO/ISO are tied to the services it performs on behalf of its market participants. The RTO/ISO would not, therefore, take an additional functions without an approving vote of its advisory committee or a directive by the Commission.

¹³ 15 U.S.C. 824d (2000).

Midwest ISO, to file its annual budget and progress reports on expenditures related to market development for informational purposes.¹⁴ The Commission reasoned that the informational filings would “provide a sufficient opportunity to review and compare the proposed costs with the actual costs and allow the Commission to monitor Midwest ISO’s cost containment efforts.”¹⁵

15. Nevertheless, in all cases, RTOs/ISOs are typically allowed recovery of all expenditures; they do not absorb losses and instead pass through all costs that they incur (e.g., NYISO has a separate charge for unbudgeted expenses; Midwest ISO’s Schedule 10 charge, while capped at \$0.15/MWh, allows for the deferral, with interest, of any costs which would cause the rate to exceed the cap during one period to be recovered during a later period when actual costs for that period are less than the capped rate).

The Subject of the Notice of Inquiry

16. The Commission wants to explore whether changes to RTO/ISO accounting, financial reporting, and cost recovery practices are necessary to ensure the rates charged by RTOs/ISOs and their member transmission-owning public utilities are just and reasonable. Rate review mechanisms, including the accounting and financial reporting requirements contained in quarterly and annual financial reports applicable to traditional public utilities may no longer be sufficiently descriptive to reflect RTO/ISO operations due to their structure and business functions. Secondly, current financial reporting by RTOs/ISOs and their member transmission-owning public utilities owners may not provide the Commission and others sufficient transparency of financial trends and emerging issues.

17. As noted above, the Commission’s expectation has been that the RTO/ISO would spend only for the benefit of its market participants. The RTO/ISO looked to stakeholders for advice on whether to pursue particular tariff or market design changes which, of course, would necessitate agreement on spending to bring those changes to fruition. However, RTO/ISO stakeholders (including member transmission-owning utilities) have alleged in various forums that this process provides an insufficient check, noting that they only see the budget

after it is finalized and they have no veto power. In this regard, member transmission-owning utilities subject to state commission regulation complain that the absence of sufficient oversight of RTO/ISO spending results in their being forced to justify before their state commissions the prudence of RTO/ISO expenditures.

Questions for Response

18. The Commission encourages any and all comments regarding the topics broadly discussed above. In addition the Commission seeks responses to the following specific questions:

A. Accounting and Financial Reporting Issues for RTOs/ISOs

1. Are the individual account descriptions and instructions under the existing USofA adequate for the functions typically performed by RTOs/ISOs? If not, what changes should be made to the account descriptions and instructions under the existing USofA to accommodate the RTO/ISO business model? Are the changes so extensive that an entirely separate USofA should be developed to accommodate RTOs/ISOs?

2. Under the existing USofA costs are accounted for as electric production, transmission, distribution or general plant. What other accounts and functional classifications should be provided for RTO/ISO transactions and events? For example, are additional revenue, expense or detailed fixed asset accounts needed?

3. Should the Commission develop a new financial reporting format for the functions typically performed by RTOs/ISOs? If so what financial information and financial-related information should be reported? If not, how may the existing annual and quarterly financial reports be changed or modified to report relevant RTO/ISO transactions and events?

4. Is additional accounting and financial reporting guidance needed for market operation and market monitoring functions of RTOs/ISOs? If so what transactions and events require additional accounting and financial reporting guidance?

5. Is there sufficient detailed financial and financial-related information being provided to users of RTO/ISO data? If not, what additional information would the users of the information find helpful and why? For example, if detailed information technology cost data is necessary, would it also be helpful for the RTO/ISO to include the cost driver of the data (e.g., quantity of desktop computers in relationship to the number of employees)?

6. Currently the quarterly and annual Commission financial reports include a schedule that requires respondents to report data concerning the transmission of electricity for others. Should RTOs/ISOs report transmission of electric for others for its Commission-jurisdictional members or should those individual members report the information in their individual filings? If the RTO/ISO should report the information, what

information should be reported and how should it be shown in the filing?

B. Accounting and Financial Reporting Issues for Public Utilities and Licensees That Are Members of an RTO/ISO

1. Are the individual account descriptions and instructions under the existing USofA useful and applicable for classifying revenues received from RTOs/ISOs? If not, what changes should be made to the account descriptions and instructions under the existing USofA to accommodate these transactions and events?

2. Are the individual account descriptions and instructions under the existing USofA useful and applicable for classifying costs related to providing various services such as ancillary services, energy markets, or costs associated with transmission congestion? If not, what changes should be made to the existing USofA to accommodate these transactions and events?

3. What additional detailed information should be collected or disclosed in the quarterly and annual Commission financial reports of individual utilities to provide greater transparency of RTO transactions and events?

4. What additional disclosures should be made in the quarterly and annual Commission financial reports of individual utilities to describe the economic effects resulting from the respondent transmitting public utility participating in an RTO?

5. Does the Commission’s USofA and existing financial reporting requirements for public utility members of RTO/ISOs provide regulators with adequate information to clearly identify which functions are performed by the RTO/ISO and which are performed by the member transmission-owning public utilities, and to ensure that costs are not being double recovered through either Commission-jurisdictional or state-jurisdictional rates? Are they adequate to determine how RTO/ISO costs billed to public utility members should enter into the determination of retail rates? If not, what changes to the Commission’s accounting and reporting rules should be made?

C. Cost Management

1. Do not-for-profit RTOs/ISOs currently have the appropriate incentives to contain costs? If not, what are the right incentives (and why would they be the right incentives) and how should they be implemented?

2. Should the Commission revisit the means by which RTO/ISO rates are reviewed, particularly with respect to cost incurrence? If so, what means should the Commission employ to ensure that RTOs/ISOs’ expenditures are prudent and their rates are just and reasonable? Would a “best practices” or “benchmark” approach, where one RTO/ISO’s expenditures in a particular cost category are measured against those of other RTOs/ISOs, be sufficient?

3. What is the appropriate role for the Commission with respect to overseeing RTO/ISO software costs? Should an RTO/ISO be required to justify contracting for the development of new software rather than using or modifying “off-the-shelf” software developed for a comparable application for or by another RTO/ISO? To what extent would

¹⁴ See, e.g., Midwest Independent Transmission System Operator, 101 FERC ¶ 61,221 (2002), *order on reh’g*, 103 FERC ¶ 61,035 (2003)

¹⁵ *Id.*, 101 FERC ¶ 61,221 at P 36.

the use of standardized or at least compatible software in neighboring RTO/ISO markets reduce the cost of doing business across RTO/ISO boundaries? How would any such standardization be accomplished?

4. To what degree should an RTO/ISO's stakeholder/advisory committee be involved in reviewing or shaping the RTO/ISO's budget and spending decisions? Are there independence considerations that should prevent or limit such review by market participants?

5. Should the Commission allow differences between RTOs/ISOs with regard to cost allocation and rate design to recover the operation and capital costs for each of their functions (e.g., tariff administration and markets for energy, ancillary service, and FTRs)? If so, how should the various rates be designed, i.e., what are the correct billing determinants for each service?

6. Should the compensation of senior RTO/ISO management be linked to specific performance measures, including cost reductions?

Procedure for Comments

19. The Commission invites interested persons to submit comments, and other information on the matters, issues and specific questions identified in this notice. Comments are due November 4, 2004. Comments must refer to Docket No. RM04-12-000, and must include the commentor's name, the organization they represent, if applicable, and their address.

20. To facilitate the Commission's review of the comments, commentors are requested to provide an executive summary of their position. Commentors are requested to identify each specific question posed by the NOI that their discussion addresses and to use appropriate headings. Additional issues the commentors wish to raise should be identified separately. The commentors should double space their comments.

21. Comments may be filed on paper or electronically via the eFiling link on the Commission's Web site at <http://www.ferc.gov>. The Commission accepts most standard word processing formats and commentors may attach additional files with supporting information in certain other file formats. Commentors filing electronically do not need to make a paper filing. Commentors that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE., Washington, DC 20426.

22. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commentors are not required to serve copies of their comments on other commentors.

Document Availability

23. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (<http://www.ferc.gov>) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

24. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number (excluding the last three digits) in the docket number field.

25. User assistance is available for eLibrary and the Commission's Web site during normal business hours. For assistance, please contact the Commission's Online Support at 1-866-208-3676 (toll free) or 202-502-6652 (e-mail at FERCOnlineSupport@ferc.gov or the Public Reference Room at 202-502-8371, TTY 202-502-8659 (e-mail at public.referenceroom@ferc.gov)

By direction of the Commission.

Magalie R. Salas,
Secretary.

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BILLING CODE 6717-01-P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

Endangered and Threatened Wildlife and Plants; 90-Day Finding for a Petition To List the Western Gray Squirrel as Endangered Rangeland

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of petition finding.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce a 90-day finding for a petition to list the western gray squirrel (*Sciurus griseus*) as endangered under the Endangered Species Act of 1973, as amended. We find the petition does not present substantial scientific or commercial information indicating that listing this species may be warranted.

DATES: The finding announced in this document was made on September 29, 2004.

ADDRESSES: Data, information, comments or questions concerning this petition should be sent to the Manager, U.S. Fish and Wildlife Service, Western Washington Fish and Wildlife Office, 510 Desmond Drive SE., Suite 102, Lacey, WA 98503. The petition finding, supporting data, and comments are available for public inspection, by appointment, during normal business hours at the above address.

FOR FURTHER INFORMATION CONTACT: Dr. L. Karolee Owens (see **ADDRESSES** section), telephone 360/753-4369, facsimile 360/753-4369.

SUPPLEMENTARY INFORMATION:

Background

Section 4(b)(3)(A) of the Endangered Species Act of 1973, as amended (Act) (16 U.S.C. *et seq.*), requires that we make a finding on whether a petition to list, delist, or reclassify a species presents substantial scientific or commercial information indicating that the petitioned action may be warranted. This finding is to be based on all information contained in the petition and available in our files at the time the finding is made.

Our standard for substantial information with regard to a 90-day petition finding is "that amount of information that would lead a reasonable person to believe that the measure proposed in the petition may be warranted" (50 CFR 424.14(b)). If the finding is that substantial information was presented, we are required to promptly commence a review of the status of the species, unless a status review has previously been initiated.

Petition

On December 24, 2002, we received a petition dated December 19, 2002, from the Institute for Wildlife Protection (IWP). The petition was submitted as a comment to our request for public comments in a 90-day finding for a petition to list the Washington population of one of the subspecies of the western gray squirrel (*Sciurus griseus griseus*) as threatened or endangered. The petitioner provided a comment letter-petition to list the western gray squirrel rangeland and two attachments. The petitioner requested that we consider listing the western gray squirrel as endangered throughout its range and evaluate "any DPS's (distinct population segments) and subspecies" of the western gray squirrel throughout its range. The petitioner did not provide any