DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

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[Docket No. RM99–2–000; Order No. 2000]

Regional Transmission Organizations

Issued December 20, 1999.

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act (FPA) to advance the formation of Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO. The Commission also codifies minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO. The Commission's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service.

EFFECTIVE DATE: This Final Rule will become effective March 6, 2000.

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Before Commissioners: James J. Hoecker, Chairman; William L. Massey, Linda Breathitt, and Curt Hebert, Jr.

I. Introduction and Summary

In 1996 the Commission put in place the foundation necessary for competitive wholesale power markets in this country—open access transmission.[1] Since that time, the industry has undergone sweeping restructuring activity, including a movement by many states to develop retail competition, the growing divestiture of generation plants by traditional electric utilities, a significant increase in the number of mergers among traditional electric utilities and among electric utilities and gas pipeline companies, large increases in the number of power marketers and independent generation facility developers entering the marketplace, and the establishment of independent system operators (ISOs) as managers of large parts of the transmission system. Trade in bulk power markets has continued to increase significantly and the Nation's transmission grid is being used more heavily and in new ways.

On May 13, 1999, the Commission proposed a rule on Regional Transmission Organizations (RTOs) that identified and discussed our concerns with the traditional means of grid management.[2] In that Notice of Proposed Rulemaking (NOPR), the Commission reviewed evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets, and that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets. These problems may be depriving the Nation of the benefits of lower prices and enhanced reliability. The comments on the NOPR overwhelmingly support the conclusion that independent regionally operated transmissions grids will enhance the benefits of competitive electricity markets. Competition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity consumers pay the lowest price possible for reliable service.

Regional institutions can address the operational and reliability issues now confronting the industry, and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. Appropriate regional transmission institutions could: (1) Improve efficiencies in transmission grid management;[3] (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation.

Thus, we believe that appropriate RTOs could successfully address the existing impediments to efficient grid operation and competition and could consequently benefit consumers through lower electricity rates resulting from a wider choice of services and service providers. In addition, substantial cost savings are likely to result from the formation of RTOs.

Based on careful consideration of the thoughtful comments submitted in response to the NOPR,[4] the Commission adopts a final rule that generally follows the approach of the NOPR. Our objective is for all transmission-owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate RTOs in a timely manner. Therefore, we are establishing in this rule minimum characteristics and functions for appropriate RTOs; a collaborative process by which public utilities and non-public utilities that own, operate or control interstate transmission facilities, in consultation with state officials as appropriate, will consider and develop RTOs; a proposal to consider transmission ratemaking reforms on a case-specific basis; an opportunity for non-monetary regulatory benefits, such as deference in dispute resolution and streamlined filing and approval procedures; and a time line for public utilities to make appropriate filings with the Commission to initiate operation of RTOs. As a result of this voluntary approach, we expect jurisdictional utilities to form RTOs. If the industry fails to form RTOs under this approach, the Commission will reconsider what further regulatory steps are in the public interest.

Pursuant to our authority under section 205 of the Federal Power Act (FPA) to ensure that rates, terms and conditions of transmission and sales for resale in interstate commerce by public utilities are just, reasonable and not unduly discriminatory or preferential, and our authority under section 202(a) of the FPA to promote and encourage regional districts for the voluntary interconnection and coordination of transmission facilities by public utilities and non-public utilities for the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy, this rule requires the following.

First, the Commission establishes minimum characteristics and functions that an RTO must satisfy in the following areas:

Minimum Characteristics:
1. Independence
2. Scope and Regional Configuration
3. Operational Authority
4. Short-term Reliability

Minimum Functions:
1. Tariff Administration and Design
2. Congestion Management
3. Parallel Path Flow
4. Ancillary Services
5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
6. Market Monitoring
7. Planning and Expansion
8. Interregional Coordination

Industry participants, however, retain flexibility in structuring RTOs that satisfy the minimum characteristics and functions. For example, we do not propose to require or prohibit any one form of organization for RTOs or require or prohibit RTO ownership of transmission facilities. The characteristics and functions could be satisfied by different organizational forms, such as ISOs, transcos, combinations of the two, or even new organizational forms not yet discussed in the industry or proposed to the Commission. Likewise, the Commission is not proposing a ''cookie cutter'' organizational format for regional transmission institutions or the establishment of fixed or specific regional boundaries under section 202(a) of the FPA.

We also establish an ''open architecture'' policy regarding RTOs, whereby all RTO proposals must allow the RTO and its members the flexibility to improve their organizations in the

[1] *See* Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and 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 No. 888), *order on reh'g,* Order No. 888–A, 62 FR 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997) (Order No. 888–A), *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), *appeal docketed,* Transmission Access Policy Study Group, *et al.* v. FERC, Nos. 97–1715 *et al.* (D.C. Cir.).

[2] Regional Transmission Organizations, Notice of Proposed Rulemaking, 64 FR 31,390 (June 10, 1999), FERC Stats. & Regs. ¶ 32,541 at 33,683–781 (1999).

[3] As discussed more fully later, appropriate regional institutions could improve efficiencies in grid management through improved pricing, congestion management, more accurate estimates of Available Transmission Capability, improved parallel path flow management, more efficient planning, and increased coordination between regulatory agencies.

[4] The Commission received 334 initial and reply comments in response to the NOPR. The commenters, and abbreviations for them as used herein, are listed in an Appendix to this Final Rule.

future in terms of structure, operations, market support and geographic scope to meet market needs. In turn, the Commission will provide the regulatory flexibility to accommodate such improvement.

Second, to facilitate RTO formation in all regions of the Nation, the Commission will sponsor and support a collaborative process to take place in the Spring of 2000. Under this process, we expect that public utilities and non-public utilities, in coordination with state officials, Commission staff, and all affected interest groups, will actively work toward the voluntary development of RTOs.

Third, we provide guidance on flexible transmission ratemaking that may be proposed by RTOs, including ratemaking treatments that will address congestion pricing and performance-based regulation. We also propose to consider on a case-by-case basis incentive pricing that may be appropriate for transmission facilities under RTO control.

Finally, all public utilities (with the exception of those participating in an approved regional transmission entity that conforms to the Commission's ISO principles) that own, operate or control interstate transmission facilities must file with the Commission by October 15, 2000, a proposal for an RTO with the minimum characteristics and functions to be operational by December 15, 2001,[5] or, alternatively, a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation. We expect that such proposals would include the transmission facilities of public utilities as well as transmission facilities of public power and other non-public utility entities to the extent possible. Through the required filings, public utilities will make known to the public any plans for RTO participation and any obstacles to RTO formation.

A public utility that is a member of an existing transmission entity that has been approved by the Commission as in conformance with the eleven ISO principles set forth in Order No. 888 must make a filing no later than January 15, 2001. That filing must explain the extent to which the transmission entity in which it participates meets the minimum characteristics and functions for an RTO, and either propose to modify the existing institution to the extent necessary to become an RTO, or explain the efforts, obstacles and plans with respect to conforming to these characteristics and functions.

The goal of this rulemaking is to form RTOs voluntarily and in a timely manner. The alternative to a voluntary process is likely to be a lengthy process that is more likely to result in greater standardization of the Commission's RTO requirements among regions. Although the Commission has specific authorities and responsibilities under the FPA to protect against undue discrimination and remove impediments to wholesale competition, we find it appropriate in this instance to adopt an open collaborative process that relies on voluntary regional participation to design RTOs that can be tailored to specific needs of each region.

II. Background

In April 1996, in Order Nos. 888[6] and 889,[7] the Commission established the foundation necessary to develop competitive bulk power markets in the United States: non-discriminatory open access transmission services by public utilities and stranded cost recovery rules that would provide a fair transition to competitive markets. Order Nos. 888 and 889 were very successful in accomplishing much of what they set out to do. However, the orders were not intended to address all problems that might arise in the development of competitive power markets. Indeed, the nature of the emerging markets and the remaining impediments to full competition that became apparent in the nearly four years since the issuance of Order Nos. 888 and 889, and the insightful comments and information presented to us by a wide array of industry participants in this rulemaking proceeding have made clear that the Commission must take further action if we are to achieve the fully competitive power markets envisioned by those orders.

A. The Foundation for Competitive Markets: Order Nos. 888 and 889

In Order Nos. 888 and 889, the Commission found that unduly discriminatory and anticompetitive practices existed in the electric industry, and that transmission-owning utilities had discriminated against others seeking transmission access.[8] The Commission stated that its goal was to ensure that customers have the benefits of competitively priced generation, and determined that non-discriminatory open access transmission services (including access to transmission information) and stranded cost recovery were the most critical components of a successful transition to competitive wholesale electricity markets.[9]

Accordingly, Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to (1) file open access non-discriminatory transmission tariffs containing, at a minimum, the non-price terms and conditions set forth in the Order, and (2) functionally unbundle wholesale power services. Under functional unbundling, the public utility must: (1) take transmission services under the same tariff of general applicability as do others; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.[10] Order No. 889 required that all public utilities establish or participate in an Open Access Same-Time Information System (OASIS) that meets certain specifications, and comply with standards of conduct designed to prevent employees of a public utility (or any employees of its affiliates) engaged in wholesale power marketing functions from obtaining preferential access to pertinent transmission system information.

During the course of the Order No. 888 proceeding, the Commission received comments urging it to require generation divestiture or structural institutional arrangements such as regional independent system operators (ISOs) to better assure non-discrimination. The Commission responded that, while it believed that

[5] An RTO proposal includes a basic agreement filed under section 205 of the FPA setting out the rules, practices and procedures under which the RTO will be governed and operated, and requests by the public utility members of the RTO under section 203 of the FPA to transfer control of their jurisdictional transmission facilities from individual public utilities to the RTO. Most RTO proposals by public utilities are likely to involve one or more filings under FPA sections 203 and 205, but the number and types of filing may vary depending upon the type of RTO proposed and the number of public utilities involved in the proposal. Under the Rule, a utility may file a petition for a declaratory order asking, for example, whether a proposed transmission entity would qualify as an RTO or if a new or innovative method for pricing transmission service would be acceptable, to be followed by appropriate filings under sections 203 and 205.

[6] *See supra* note 1.

[7] Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, Order No. 889, 61 FR 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889–A, 62 FR 12,484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889–B, 81 FERC ¶ 61,253 (1997).

[8] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,682.

[9] *Id.* at 31,652.

[10] *Id.* at 31,654–55.

ISOs had the potential to provide significant benefits, efforts to remedy undue discrimination should begin by requiring the less intrusive functional unbundling approach. Subsequent to issuance of Order No. 888, it has become apparent that several types of regional transmission institutions, in addition to the kinds of ISOs approved to date, may also be able to provide the benefits attributed to ISOs in Order No. 888.

Order No. 888 set forth 11 principles for assessing ISO proposals submitted to the Commission.[11] Order No. 888 also stated:

> [W]e see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace. As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required.[12]

Below, we summarize our experiences with functional unbundling from the date of issuance of Order Nos. 888 and 889.

B. Developments Since Order Nos. 888 and 889

In the nearly four years since Order Nos. 888 and 889 were issued, numerous significant developments have occurred in the electric utility industry. Some of these reflect changes in governmental policies; others are strictly industry-driven. These activities have resulted in a considerably different industry landscape from the one faced at the time the Commission was developing Order No. 888, resulting in new regulatory and industry challenges.

Order Nos. 888 and 889 required a significant change to the way many public utilities have done business for most of this century, and most public utilities accepted these changes and made substantial good faith efforts to comply with the new requirements. Virtually all public utilities have filed tariffs stating rates, terms and conditions for comparable service to third-party users of their transmission systems. In addition, improved information about the transmission system is available to all participants in the market at the same time that it is available to the public utility's merchant function and market affiliate as a result of utility compliance with the OASIS regulations.

The availability of tariffs and information about the transmission system has fostered a rapid growth in dependence on wholesale markets for acquisition of generation resources. Areas that have experienced generation shortages have seen rapid development of new generation resources. For example, in the Northeast Power Coordinating Council (NPCC) region (including New England, New York and parts of eastern Canada), where there was deep concern about adequacy of generation supply only three years ago, approximately 30,000 MW of generation is proposed or actually under construction.[13] That response comes almost entirely from independent generating plants, which are able to sell power into the bulk power market through open access to the transmission system. Power resources are now acquired over increasingly large regional areas, and interregional transfers of electricity have increased. The very success of Order Nos. 888 and 889, and the initiative of some utilities that have pursued voluntary restructuring beyond the minimum open access requirements, have placed new stresses on regional transmission systems—stresses that call for regional solutions.

1. Industry Restructuring and New Stresses on the Transmission Grid

Open access transmission and the opening of wholesale competition in the electric industry have brought an array of changes in the past several years: Divestiture by many integrated utilities of some or all of their generating assets; significantly increased merger activity both between electric utilities and between electric and natural gas utilities; increases in the number of new participants in the industry in the form of both independent and affiliated power marketers and generators as well as independent power exchanges; increases in the volume of trade in the industry, particularly sales by marketers; state efforts to introduce retail competition; and new and different uses of the transmission grid.

With respect to divestiture, since August 1997, generating facilities representing approximately 50,000 MW of generating capacity have been sold (or are under contract to be sold) by utilities, and an additional 30,000 MW is currently for sale. In total, this represents more than ten percent of U.S. generating capacity. In all, 27 utilities have sold all or some of their generating assets and seven others have assets for sale. Buyers of this generating capacity have included traditional utilities with specified service territories as well as independent power producers with no required service territory.

Since Order No. 888 was issued, more than 40 applications have been filed for Commission approval of proposed mergers involving public utilities.[14] Most of these merger proposals involve electric utilities with contiguous service areas, although some of the proposed mergers have been between utilities with non-contiguous service areas. In addition, an increasing number of applications involve the combination of electric and natural gas assets.

There has been significant growth in the volume of trading, and particularly the number of marketers, in the wholesale electricity market. For example, in the first quarter of 1995, according to power marketer quarterly filings, marketer sales traded by only eight active power marketers, totaled 1.8 million MWh. By the first quarter of 1999, such sales escalated to over 400 million MWh, traded by over 100 power marketers.[15]

The Commission has granted market-based rate authority to more than 800 entities, of which nearly 500 are power marketers, (including over 100 marketers affiliated with investor-owned utilities). The remaining entities include approximately equal numbers of affiliated power producers, investor-owned utilities and other utilities.[16]

State commissions and legislatures have been active in the past few years studying competitive options at the retail level, setting up pilot retail access programs, and, in many states, implementing full scale retail access programs. As of November 1, 1999, twenty-one states had enacted electric restructuring legislation, three had issued comprehensive regulatory orders, and twenty-six states plus the District of Columbia had legislation or orders pending or investigations underway.[17] Fifteen states had implemented full-

[11] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730.

[12] *Id.* at 31,655.

[13] Based on data supplied to the Commission by Resource Data International.

[14] *See* Commission's website, www.ferc.fed.us/electric/mergers.

[15] *See* Commission's website, www.ferc.fed.us/electric/PwrMkt. The Commission recognizes that a significant portion of the sales represent the retrading of power by a number of different market participants, such that there may be multiple resales of the same generation. Nonetheless, the volume of and intensity of trading continues to increase in the wholesale electricity market.

[16] *See* Commission's website, www.ferc.fed.us/electric.

[17] *See* the Energy Information Administration website, www.eia.doe.gov/cneaf/electricity/chg str/regmap.html.

scale or pilot retail competition programs that offer a choice of suppliers to at least some retail customers. Eight states have initiated programs to offer access to retail customers by a date certain.

Because of the changes in the structure of the electric industry, the transmission grid is now being used more intensively and in different ways than in the past. The Commission is concerned that the traditional approaches to operating the grid are showing signs of strain. According to the North American Electric Reliability Council (NERC), ''the adequacy of the bulk transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions.'' [18] These changes in the use of the transmission system ''will test the electric industry's ability to maintain system security in operating the transmission system under conditions for which it was not planned or designed.'' [19] It should be noted that, despite the increased transmission system loadings, NERC believes that the ''procedures and processes to mitigate potential reliability impacts appear to be working reliably for now,'' and that even though the system was particularly stressed during the summer of 1998, ''the system performed reliably and firm demand was not interrupted due to transmission transfer limitations.'' [20]

An indication that the increased and different use of the transmission system is stressing the grid is the increased use of transmission line loading relief (TLR) procedures.[21] And, according to published reports, the incidence of TLRs is growing. While in all of 1998 over 300 TLRs were called, in the first ten months of 1999, over 400 TLRs have been called, resulting in over 8,000 MW of power curtailment in the three-month summer period beginning June 1999.[22]

It appears that the planning and construction of transmission and transmission-related facilities may not be keeping up with increased requirements. According to NERC, ''business is increasing on the transmission system, but very little is being done to increase the load serving and transfer capability of the bulk transmission system.'' [23] The amount of new transmission capacity planned over the next ten years is significantly lower than the additions that had been planned five years ago, and most of the planned projects are for local system support.[24] NERC states that, ''The close coordination of generation and transmission planning is diminishing as vertically integrated utilities divest their generation assets and most new generation is being proposed and developed by independent power producers.'' [25]

The transition to new market structures has resulted in new challenges and circumstances. For example, during the week of June 22–26, 1998, the wholesale electric market in the Midwest experienced numerous events that led to unprecedented high spot market prices. Spot wholesale market prices for energy briefly rose as high as $7,500 per MWh, compared with an average price for the summer of approximately $40 per MWh in the Midwest if the pricing abnormalities are excluded.[26] This experience led to calls for price caps, allegations of market power, and a questioning of the effectiveness of transmission open access and wholesale electric competition.

The Commission staff undertook an investigation of the pricing abnormalities. Staff's report concluded that the unusually high price levels were caused by a combination of factors, particularly above-average generation outages, unseasonably hot temperatures, storm-related transmission outages, transmission constraints, poor communication of price signals, lowered confidence in the market due to a few contract defaults, and inexperience in dealing with competitive markets.[27]

The Commission's staff found that the market institutions were not adequately prepared to deal with such a dramatic series of events. Regarding regional transmission entities, the staff report observed: ''The necessity for cooperation in meeting reliability concerns and the Commission's intent to foster competitive market conditions underscores the importance of better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation.'' [28] Support for this view comes from many sources. For example, the Public Utilities Commission of Ohio, in its own report on the high spot market prices, recommended that policy makers ''take unambiguous action to require coordination of transmission system operations by regionwide Independent System Operators.'' [29]

On September 29, 1998, the Secretary of Energy Advisory Board Task Force on Electric System Reliability published its final report.[30] The Task Force was convened in January 1997 to provide advice to the Department of Energy on critical institutional, technical, and policy issues that need to be addressed in order to maintain bulk power electric system reliability in a more competitive industry. The Task Force found that ''the traditional reliability institutions and processes that have served the Nation well in the past need to be modified to ensure that reliability is maintained in a competitively neutral fashion;'' that ''grid reliability depends heavily on system operators who monitor and control the grid in real time;'' and that ''because bulk power systems are regional in nature, they can and should be operated more reliably and efficiently when coordinated over large geographic areas.'' [31]

The report noted that many regions of the United States are developing ISOs as a way to maintain electric system reliability as competitive markets develop. According to the Task Force, ISOs are significant institutions to assure both electric system reliability and competitive generation markets. The Task Force concluded that a large ISO would: (1) Be able to identify and address reliability issues most effectively; (2) internalize much of the loop flow caused by the growing number of transactions; (3) facilitate transmission access across a larger

[18] Reliability Assessment 1998–2007, North American Electric Reliability Council (September 1998), at 26 (Reliability Assessment).

[19] *Id.*

[20] *Id.*

[21] The TLR procedures are designed to remedy overloads that result when a transmission line or other transmission equipment carries or will carry more power than its rating, which could result in either power outages or damage to property. The TLR procedures are designed to bring overloaded transmission equipment to within NERC's Operating Security Limits essentially by curtailing transactions contributing to the overload. *See* North American Electric Reliability Council, 85 FERC ¶ 61,353 (1998) (*NERC*).

[22] *Power Markets Week,* November 8, 1999 at 1, *citing* NERC data.

[23] Reliability Assessment at 26.

[24] *Id.* at 7.

[25] *Id.*

[26] *See Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998,* (Sept. 22, 1998) (Staff Price Spike Report) at 3–8 to 3–11. Unusually high spot market wholesale prices also occurred during the summer of 1999. The Commission is not aware that any formal evaluations of market data have been performed for that occurrence of price abnormalities.

[27] *Id.* at v.

[28] *Id.* at 5–8.

[29] Ohio's Electric Market, June 22–26, 1998, *What Happened and Why, A Report to the Ohio General Assembly,* at iii.

[30] *Maintaining Reliability in a Competitive U.S. Electricity Industry; Final Report of the Task Force on Electric System Reliability* (Sept. 29, 1998) (Task Force Report). The Task Force was comprised of 24 members representing all major segments of the electric industry, including private and public suppliers, power marketers, regulators, environmentalists, and academics.

[31] Task Force Report at x-xi.

portion of the network, consequently improving market efficiencies and promoting greater competition; and (4) eliminate ''pancaking'' of transmission rates, thus allowing a greater range of economic energy trades across the network.[32]

2. Successes, Failures, and Haphazard Development of Regional Transmission Entities

Since Order No. 888 was issued, there have been both successful and unsuccessful efforts to establish ISOs, and other efforts to form regional entities to operate the transmission facilities in various parts of the country. While we are encouraged by the success of some of these efforts, it is apparent that the results have been inconsistent, and much of the country's transmission facilities remain outside of an operational regional transmission institution.

Proposals for the establishment of five ISOs have been submitted to and approved, or conditionally approved, by the Commission. These are the California ISO,[33] PJM ISO,[34] ISO New England,[35] the New York ISO,[36] and the Midwest ISO.[37] In addition, the Texas Commission has ordered an ISO for the Electric Reliability Council of Texas (ERCOT).[38] Moreover, our international neighbors in Canada and Mexico are also pursuing electric restructuring efforts that include various forms of regional transmission entities.[39]

The PJM, New England and New York ISOs were established on the platform of existing tight power pools. It appears that the principal motivation for creating ISOs in these situations was the Order No. 888 requirement that there be a single systemwide transmission tariff for tight pools. In contrast, the establishment of the California ISO and the ERCOT ISO was the direct result of mandates by state governments. The Midwest ISO, which is not yet operational, is unique. It was neither required by government nor based on an existing institution. Two states in the region subsequently required utilities in their states to participate in either a Commission-approved ISO (Illinois and Wisconsin), or sell their transmission assets to an independent transmission company that would operate under a regional ISO (Wisconsin).

As part of general restructuring initiatives, several states now require independent grid management organizations. For example, an Illinois law required that its utilities become members of a FERC-approved regional ISO by March 31, 1999, and Wisconsin law gives its utilities the option of joining an ISO or selling their transmission assets to an independent transmission company by June 30, 2000. In both states, the backstop is a single-state organization if regional organizations are not developed. Recently, Virginia,[40] Arkansas[41] and Ohio[42] have also enacted legislation requiring their electric utilities to join or establish regional transmission entities.

The approved ISOs have similarities as well as differences. All five Commission-approved ISOs operate, or propose to operate, as non-profit organizations. All five ISOs include both public and non-public utility members. However, among the five, there is considerable variation in governance, operational responsibilities, geographic scope and market operations. Four of the ISOs rely on a two-tier form of governance with a non-stakeholder governing board on top that is advised, either formally or informally, by one or more stakeholder groups. In general, the final decision making authority rests with the independent non-stakeholder board. One ISO, the California ISO, uses a board consisting of stakeholders and non-stakeholders.

Four of the five ISOs operate a single control area, but the large Midwest ISO does not currently plan to operate a single control area. Three are multi-state ISOs (New England, PJM and Midwest), while two ISOs (California and New York) currently operate within a single state. The current Midwest ISO members do not encompass one contiguous geographic area. The ISO New England administers a separate NEPOOL tariff, while the other four administer their own ISO transmission tariffs.

Three ISOs operate or propose to operate centralized power markets (New England, PJM and New York), and one ISO (California) relies on a separate power exchange (PX) to operate such a market.[43] The Midwest ISO has not proposed an ISO-related centralized market for its region.[44] In addition, at least one separate PX has begun to do business in California apart from the PX established through the restructuring legislation.[45]

The existing ISOs are also evolving in terms of their governance structure and as a result of operating experience with the transmission systems and the various markets they operate. For example, the Commission rejected the original governance proposals for two ISOs: the New England ISO and New York ISO. In both cases, the Commission concluded that the vertically integrated utility members of the ISO would have too much voting power in the various advisory committees that provide advice and recommendations to the non-stakeholder Boards. The ISOs resubmitted governance proposals that gave balanced representation to the various sectors of stakeholders, and the Commission subsequently approved both revised governance structures.

In addition, the Commission has considered a number of significant modifications of market rules proposed by the existing ISOs in the seven months since issuance of the RTO

[32] *Id.* at 76.

[33] Pacific Gas & Electric Company, *et al.,* 77 FERC ¶ 61,204 (1996), *order on reh'g,* 81 FERC ¶ 61,122 (1997) *(Pacific Gas & Electric).*

[34] Pennsylvania-New Jersey-Maryland Interconnection, *et al.,* 81 FERC ¶ 61,257 (1997), *order on reh'g,* 82 FERC ¶ 61,047 (1998) *(PJM).*

[35] New England Power Pool, 79 FERC ¶ 61,374 (1997), *order on reh'g,* 85 FERC ¶ 61,242 (1998) *(NEPOOL).*

[36] Central Hudson Gas & Electric Corporation, *et al.,* 83 FERC ¶ 61,352 (1998), *order on reh'g,* 87 FERC ¶ 61,135 (1999) *(Central Hudson).*

[37] Midwest Independent Transmission System Operator, *et al.,* 84 FERC ¶ 61,231, *order on reconsideration,* 85 FERC ¶ 61,250, *order on reh'g,* 85 FERC ¶ 61,372 (1998) *(Midwest ISO).*

[38] *See* 16 Texas Administrative Code § 23.67(p). Furthermore, on June 18, 1999, S.B.7 was enacted to restructure the Texas electric industry allowing retail competition. The bill requires retail competition to begin by January 2002. Rates will be frozen for three years, and then a six percent reduction will be required for residential and small commercial consumers.

[39] *See* Policy Proposal for Structural Reform of the Mexican Electricity Industry, Secretary of Energy, Mexico (Feb. 1999); Third Interim Report of the Ontario Market Design Committee (Oct. 1998); TransAlta Enterprises Corporation, 75 FERC ¶ 61,268 at 61,875 (1996) (recognition of the restructuring in the Province of Alberta, Canada to create a Grid Company of Alberta).

[40] *See* Virginia Electric Utility Restructuring Act, S1269 (Mar. 25, 1999). In Virginia, electric utilities are required by January 2001, to join or establish regional transmission entities.

[41] *See* The Arkansas Electric Consumer Choice Act of 1999, Act 1, 82nd General Assembly (Apr. 1999).

[42] *See* Amended Substitute Senate Bill No. 3, 123rd General Assembly (July 6, 1999).

[43] The California PX offers day-ahead and hour-ahead markets and the ISO operates a real-time energy market. Participation in the PX market is voluntary except that the three traditional investor-owned utilities in California must bid their generation sales and purchases through the PX for the first five years. New York will offer day-ahead and real-time energy markets that will be operated by the ISO. PJM and New England offer only real-time energy markets, although PJM has proposed to operate a day-ahead market. The ERCOT ISO is the only other ISO that does not currently operate a PX.

[44] There are indications, however, that the Midwest ISO is considering the formation of a power exchange. *See* Joint Committee for the Development of a Midwest Independent Power Exchange, ''Solicitation of Interest-Creation of an Independent Power Exchange for the U.S. Midwest,'' February 5, 1999.

[45] *See* Automated Power Exchange, Inc., 82 FERC ¶ 61,287, *reh'g denied,* 84 FERC ¶ 61,020 (1998), *appeals docketed,* No. 98–1415 (D.C. Cir. Sept. 14, 1998) and No. 98–1419 (D.C. Cir. Sept. 14, 1998).

NOPR. In particular, a number of rules for the California ISO and New England ISO have been modified, affecting the products traded in, and the timing of, the markets for energy, ancillary services, balancing services and transmission.

An additional few transmission restructuring proposals that were pending as of the date of issuance of the RTO NOPR have been approved by the Commission, and others have been filed since that date. In July 1999, the Commission granted a petition for declaratory order filed by Entergy Services Inc., in which the majority concluded that passive ownership of a transmission entity by a generating company or other market participant could meet the ISO principles contained in Order No. 888. The order stated, however, that the passive ownership must be properly designed, such that the transmission entity is truly independent of the market participants.[46] Another filing that was pending when the NOPR was issued was the request by FirstEnergy to sell its transmission assets to a newly-formed affiliate. The Commission approved the disposition of jurisdictional facilities, noting that the proposed action would not adversely affect competition, rates or regulation. In addition, the Commission noted that the creation of the transmission-owning affiliate would facilitate the subsequent transfer of FirstEnergy's transmission facilities to an RTO, which FirstEnergy pledged to do within two years of Commission approval of the disposition of facilities to its affiliate.[47]

Since issuance of the RTO NOPR, the Alliance Companies filed a proposal to create an RTO. Applicants suggest that the RTO could take one of two forms, either an ISO or a transco, but note that they prefer a transco configuration in which, at least initially, the five transmission-owning participants could hold five percent ownership stakes in the transco.[48]

Not all efforts to create ISOs have been successful. For example, after more than two years of effort, the proponents of the IndeGO (*Inde*pendent *G*rid *O*perator) ISO in the Pacific Northwest and Rocky Mountain regions ended their efforts to create an ISO.[49] More recently, members of the Mid-American Power Pool (MAPP), an existing power pool that covers six U.S. states and two Canadian provinces, failed to achieve consensus for establishing a long-planned ISO.[50] In the Southwest, proponents of the Desert STAR ISO have not been able to reach agreement to date on a formal proposal after more than two years of discussion.[51] In the interim period, some of the participants in the Desert STAR ISO have filed at the Commission a proposal to create the Mountain West Independent Scheduling Administrator, which would oversee the scheduling of transmission service within Nevada.[52]

Various reasons have been advanced to explain the difficulty in forming a voluntary, multi-state ISO. Reasons include: "cost shifting," which involves increases in transmission rates for some parties; disagreements about sharing of ISO transmission revenues among transmission owners; difficulties in obtaining the participation of publicly-owned transmission facilities; concerns about the loss of transmission rights and prices embedded in existing transmission agreements; and the preference of certain transmission owners to sell or transfer their transmission assets to a for-profit transmission company in lieu of handing over control to a non-profit ISO.

3. The Commission's ISO and RTO Inquiries; Conferences With Stakeholders and State Regulators

In light of the various restructuring activities occurring throughout the United States, the Commission has held 11 public conferences in nine different cities across the country to hear the views of industry, consumers, and state regulators with respect to the need for RTOs and their appropriate roles and responsibilities.

The Commission initiated an inquiry in March 1998 pertaining to its policies on ISOs. A notice establishing procedures for a conference gave the following rationale:

> In Order Nos. 888 and 889 and their progeny, the Commission established the fundamental principles of non-discriminatory open access transmission services. Nevertheless, many issues remain to be addressed if the Nation is to fully realize the benefits of open access and more competitive electric markets.
>
> * * * * *
>
> Given the dramatic changes taking place in both wholesale and retail electric markets and the many proposals under consideration with respect to the creation of ISOs or other transmission entities, such as transmission-only utilities, it is time for the Commission to take stock of its policies in order to determine whether they appropriately support our dual goals of eliminating undue discrimination and promoting competition in electric power markets.[53]

Accordingly, the Commission held a series of eight conferences in 1998 to gain insight into participants' views on the formation and role of ISOs in the electric utility industry. The first conference was held in April 1998 at the Commission's offices in Washington, D.C. Between May 28 and June 8, 1998, the Commission held seven regional conferences in Phoenix, Kansas City, New Orleans, Indianapolis, Portland, Richmond and Orlando. As a result of these conferences, the Commission heard approximately 145 oral presentations and received a large number of written comments on the appropriate size, scope, organization and functions of regional transmission institutions. A number of different of viewpoints were expressed.[54]

On October 1, 1998, the Secretary of Energy delegated his authority under section 202(a) of the FPA to the Commission. In doing so, the Secretary stated that section 202(a) "provides DOE with sufficient authority to establish boundaries for Independent System Operators (ISOs) or other appropriate transmission entities." [55] The Secretary also stated: "FERC is also increasingly faced with reliability-related issues. Providing FERC with the authority to establish boundaries for ISOs or other appropriate transmission entities could aid in the orderly formation of properly-sized transmission institutions and in addressing reliability-related issues, thereby increasing the reliability of the transmission system."

On November 24, 1998, we gave notice in this docket of our intent to initiate a consultation process with State commissions pursuant to section

[46] *See* Entergy Services, Inc., 88 FERC ¶ 61,149 (1999) (Commissioner Massey dissented from this order).

[47] *See* FirstEnergy Operating Companies, *et al.*, 89 FERC ¶ 61,090 (1999).

[48] *See* Application of Alliance Companies in Docket No. ER99–3144–000 (filed June 3, 1999). The Commission issued an order on this application concurrently with the issuance of this Final Rule. *See* Alliance Companies, 89 FERC ¶ (1999) (*Alliance Companies*).

[49] Recently, however, parties in the Pacific Northwest have resumed RTO discussions.

[50] However, trade press reports suggest that while MAPP members continue to try to reach consensus, the Midwest ISO is in discussion with MAPP members to join the Midwest ISO. *See Inside FERC,* July 26, 1999; *The Energy Report,* Nov. 1, 1999 at 931.

[51] Recent press reports, however, indicate that Desert STAR has incorporated as a non-profit organization, a first step toward the launch of an ISO. *See Energy Daily,* Nov. 5, 1999 at 2.

[52] *See* Application of Mountain West Independent Transmission Administrator in Docket No. ER99–3719–000 (filed July 23, 1999).

[53] Inquiry Concerning the Commission's Policy on Independent System Operators, Notice of Conference, Docket No. PL98–5–000, at 1–2 (March 13, 1998).

[54] A summary of those views was included as Appendix A to the NOPR in this docket.

[55] 63 FR 53,889 (Oct. 7, 1998).

202(a).[56] The purpose of the consultations was to afford State commissions a reasonable opportunity to present their views with respect to appropriate boundaries for regional transmission institutions and other issues relating to RTOs. Conferences with State commissioners were held in St. Louis, Missouri, on February 11, 1999; in Las Vegas, Nevada, on February 12, 1999; and in Washington, D.C., on February 17, 1999. In all, we heard oral presentations by representatives of 41 state commissions during these consultations, with others monitoring or providing written comments.[57] During these sessions, we received much valuable advice. Furthermore, we have had additional consultations since issuance of the RTO NOPR in May 1999.

III. Discussion

A. Existing Barriers and Impediments To Achieving Fully Competitive Electricity Markets

In the NOPR, the Commission expressed its belief that there remain important transmission-related impediments to a competitive wholesale electric market. The Commission grouped these remaining impediments into two broad categories: (1) The engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid, and (2) continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own or their affiliates' power marketing activities.[58]

With respect to engineering and economic inefficiencies, the NOPR noted that the transmission facilities of any one utility in a region are part of a larger, integrated transmission system which, from an electrical engineering perspective, operates as a single machine.[59] Engineering and economic inefficiencies occur because each separate operator usually makes independent decisions about the use, limitations and expansion of its piece of the interconnected grid based on incomplete information, even though any action taken by one transmission provider can have major and instantaneous effects on the transmission facilities of all other transmission providers. The Commission noted that, while this was not a new phenomenon, the demands placed on the transmission grid had changed in recent years due to (1) increases in bulk power trade, (2) large shifts in power flows, and (3) an increasingly de-integrated and decentralized competitive power industry.[60] As a consequence of these changes in trade patterns and industry structure, certain operational problems had become more significant and difficult to resolve.

Engineering and Economic Inefficiencies. The NOPR identified a number of specific economic and engineering inefficiencies. First, the NOPR noted that the reliability of the nation's bulk power system was being stressed in ways that have never been experienced before, and questioned the continued feasibility of one-on-one coordination of an interconnected transmission grid encompassing more than 100 transmission owners and 140 separate control areas.[61] Second, the NOPR observed that there were increasing difficulties in accurately computing Total Transmission Capacity (TTC) and Available Transmission Capacity (ATC), assessments that require reliable and timely information about load, generation, facility outages and transactions on neighboring systems, as well as consistency in methodologies among systems.[62] Third, the NOPR noted that efficient congestion management required regional actions, and that the current methods for managing congestion (*e.g.,* Transmission Line Loading Relief procedures in the Eastern Interconnection), which do not attempt to optimize regional congestion relief, were cumbersome, inefficient and disruptive to bulk power markets.[63] Fourth, the NOPR expressed concern that the uncertainty associated with transmission planning and expansion had increased with the increasing number and distance of unbundled transactions and the wider variation in generation dispatch patterns. The NOPR pointed to a noticeable decline in planned transmission investments and expressed concern that, without a regional approach to planning and expansion, it would be difficult to address complex and controversial issues that arise when the benefits of an expansion do not necessarily accrue to the transmission system that must undertake the expansion.[64] Finally, the NOPR explained that pancaked transmission rates (where a separate access charge is assessed every time the transaction contract path crosses the boundary of another transmission owner) restrict the size of regional power markets. The Commission added that the balkanization of electricity markets hurts consumers who pay higher transmission rates and have access to fewer generation options.[65]

Continuing Opportunities for Undue Discrimination. With respect to continuing opportunities for undue discrimination, the NOPR observed that, when utilities control monopoly transmission facilities and also have power marketing interests, they have poor incentives to provide equal quality transmission service to their power marketing competitors.[66] The NOPR explained that the Commission had made this point in Order No. 888:

> It is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices.[67]

In the NOPR, the Commission noted that functional unbundling does not change the incentives of vertically integrated utilities to use their transmission assets to favor their own generation, but instead attempt to reduce the ability of utilities to act on those incentives.[68]

The NOPR expressed concern about continuing indications that transmission service problems related to discriminatory conduct remain and concluded that these problems are impeding competitive wholesale power markets.[69] The NOPR also noted that

[56] Regional Transmission Organizations, Notice of Intent to Consult with State Commission, 63 FR 66,158 (Dec. 1, 1998), FERC Stats & Regs. ¶ 35,534 (1998).

[57] See Appendix for a list of commenters.

[58] FERC Stats. & Regs. ¶ 32,541 at 33,696.

[59] *Id.* at 33,697.

[60] *See id.*

[61] *See id.* at 33,699.

[62] *Id.* at 33,700.

[63] *Id.* at 33,701–02.

[64] *See id.* at 33,702–03.

[65] *Id.* at 33,703.

[66] *Id.* at 33,704.

[67] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,682.

[68] As noted in the NOPR, in Order No. 888, the Commission received and considered numerous comments that functional unbundling was unlikely to work, and that more drastic restructuring, such as corporate unbundling, was needed. For example, the Federal Trade Commission advised the Commission that a functional unbundling approach "* * * would leave in place the incentive and opportunity for some utilities to exercise market power in the regulated system. Preventing them from doing so by enforcing regulations to control their behavior may prove difficult." However, the Commission decided at the time to adopt the less intrusive and less costly remedy of functional unbundling. FERC Stats. & Regs. ¶ 32,541 at 33,707.

[69] The NOPR described specific examples of undue discrimination that had been brought to its

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instances of actual discrimination may be undetectable in a non-transparent market and, in any event, it is often hard to determine, on an after-the-fact basis, whether an action was motivated by an intent to favor affiliates or simply reflected the impartial application of operating or technical requirement. The NOPR added that, while continued discrimination may be deliberate, it could also result from the failure to make sufficient efforts to change the way integrated utilities have done business for many years. The Commission expressed concern that the difficulty in determining whether there has been compliance with our regulations raises the question as to whether functional unbundling is an appropriate long-term regulatory solution.

The NOPR explained that the Commission considers allegations of discrimination, even if not reduced to formal findings, to be a serious concern for two reasons. First, this can be indicative of additional, unreported, discriminatory actions, because there are significant disincentives to filing and pursuing formal complaints that would result in definitive findings.[70] The NOPR expressed a concern that actual problems with functional unbundling may be more pervasive than formally adjudicated complaints would suggest. Second, the NOPR explained that allegations of discrimination are serious because, if nothing else, they represent a perception by market participants that the market is not working fairly. If market participants perceive that other participants have an unfair advantage through their ownership or control of transmission facilities, it can inhibit their willingness to participate in the market, thus thwarting the development of robust competition. The NOPR added that such mistrust can also harm reliability.[71]

The NOPR explained the potential for undue discrimination increases in a competitive environment unless the market can be made structurally efficient and transparent with respect to information, and equitable in its treatment of competing participants. Also, a system that attempts to control behavior that is motivated by economic self-interest through the use of standards of conduct will require constant and extensive policing and requires the Commission to regulate detailed aspects of internal company policy and communication. The NOPR added that functional unbundling does not necessarily promote light-handed regulation and undoubtedly imposes a cost on those entities that have to comply with the standards of conduct and abide by rules that limit the flexibility of their internal management activities. The NOPR stated that the perception that many entities that operate the transmission system cannot be trusted is not a good foundation on which to build a competitive power market, and it created needless uncertainty and risk for new investments in generation.[72]

Comments. Engineering and Economic Inefficiencies. Virtually all commenters support the NOPR's premise that engineering and economic inefficiencies exist in the operation, planning and expansion of the regional transmission grid and that these inefficiencies hinder electric system reliability and a fully competitive bulk power market.[73] Many commenters state further that, in the new industry structure, coordinated regional transmission planning has become a thing of the past and new transmission additions that will benefit reliable grid operations are being delayed.[74]

FMPA states that grid fragmentation harms reliability.[75] NU and EPRI note that recent demand growth has meant new stresses on grid reliability and there is less coordination of generation and transmission planning. TXU Electric states that, as the shift from regulation to competition accelerates, and restructuring efforts proliferate, the regional transmission grid is being exposed to stresses that cannot be alleviated without regional solutions.

WPPI describes a situation in 1997 in which the 345-kV transmission facility between MAPP and MAIN was overloaded as a result of transactions scheduled within MAPP, and Wisconsin operators became aware of the problem only when the constrained 345-kV facility automatically separated in response to the overload. WPPI explains that, with the 345-kV facility shut down, other transmission facilities in the region overloaded, causing the transmission system over a large region to come perilously close to a blackout. WPPI adds that, because transmission providers do not have information about their neighbors' on-system transactions to serve native load, they are unable to predict the impact of potential TLR events. WPPI says that, in the face of this uncertainty, transmission providers have to make overly conservative, but inaccurate assumptions which unnecessarily reduce the amount of transmission capacity available to the market.

TAPS states that, when the owners of a constrained interface between MAPP and MAIN tried to remove the line for service for maintenance, they found that 500 MW of flow remained on the line even after all scheduled transactions were terminated. TAPS explains that there were so many transactions in the region at the time that transmission operators could not determine the source of this 500 MW loop flow and were unable to ask other parties to cut their schedules to permit the necessary maintenance.[76] TAPS asserts that transmission owners have engaged in ''creative'' concepts such as CBM to reduce ATC and argues that price spikes are exacerbated, if not caused by the failure to have regional transmission information and control in one place.[77]

TDU Systems complaint that the current system balkanizes regions into a series of submarkets, each with its own dominant incumbent transmission owner/generator that collects its own transmission toll.

EPRI contends that the current off-line ATC calculations result in inconsistencies of ATC values. Entergy argues that the accuracy of ATC will continue to be a problem as long as contract path pricing is used.[78]

Minnesota Power notes that reliability across the broader region suffers simply because of different standards for ATC calculations within and across NERC

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attention through formal complaints, informal complaints made to the Commission's enforcement hotline, oral and written comments made in conjunction with public conferences held by the Commission, and pleadings filed with the Commission in various dockets. The complaints generally involved: (1) Calculation and posting of ATC in a manner favorable to the transmission provider; (2) standards of conduct violations, (3) line loading relief and congestion management, and (4) OASIS sites that are difficult to use. *See id.* at 33,707–13.

[70] As noted in the NOPR, transmission customers are reluctant to make even informal complaints because they fear retribution by their transmission supplier; the complaint process is costly and time-consuming; the Commission's remedies for violations do not impose sufficient financial consequences on the transmission provider to act as a significant deterrent; and, in the fast-paced business of power marketing, there may be no adequate remedy for the lost short-term sales opportunities in after-the-fact enforcement. *See* FERC Stats. & Regs. ¶ 32,541 at 33,706.

[71] *Id.*

[72] *See id.* at 33,714.

[73] *See, e.g.,* Duquesne, Entergy, Florida Power Corp., NU, Kentucky Commission, NECPUC, Ohio Commission, Texas Commission, DOE, American Forest, Arkansas Cities, East Texas Cooperatives, EPSA, First Rochdale, FMPA, Oglethorpe, PNGC, Powerex, Public Citizen, SoCal Cities, Sonat, Williams.

[74] *See, e.g.,* EPRI, Florida Power Corp, Duquesne, Entergy, SoCal Cities, Merrill Energy, TAPS, IPCF, Powerex.

[75] FMPA at 24.

[76] TAPS, Appendix A, at 8

[77] TAPS, Appendix A at 2–5.

[78] Entergy at 8.

regions and, indeed, different terminology and operating practices. Minnesota Power states that: the market currently suffers as participants attempt to deal with multiple OASIS sites; existing tagging and reservation practices that limit transactions due to the complexity of arrangements; its transactions are subject to curtailment pursuant to two different procedures, NERC TLR and MAPP LLR; and congestion management alternatives to line loading relief have not succeeded because they lack regional coordination. Minnesota Power argues that energy price volatility will continue to increase unless there is a viable process, supported by transmission rights and secondary transfer markets, where a participant can secure transmission daily, or as needed, to bring the least cost supply to its customers.

EPSA asserts that one of the major impediments to robust competitive bulk power markets is the current balkanization of the system with dozens of individual utilities, NERC Regional Councils, and security coordinators, and state laws and regulations imposing a patchwork of often inconsistent and incompatible rules for the use of the interstate transmission system. EPSA argues that the operational and economic inefficiencies detailed in the NOPR are not unique to certain region as and may be most pronounced in those regions where competition has yet to take hold.[79]

SoCal Edison states that existing transmission systems were designed to serve native load customers in a defined area, in the most efficient manner possible, in conjunction with the generation that it owned and operated, and were not designed to function as common carriers. SoCal Edison concludes that that radical changes in downstream generation markets are having, and will continue to have, significant and largely adverse effects of transmission systems. Consumers Energy echoes this concern, noting that it should be obvious that the current transmission system was designed to deliver locally generated power to local markets with interfaces used primarily for reliability purposes. Consumers Energy states that the system is simply not engineered to move large quantities of power from many distant generation sources to millions of end users.

Williams concludes that problems with congestion management, pancaked transmission rates, parallel path or loop flows, inaccurate ATC postings, and transmission facilities management and expansion planning continue to impede the development of robust, competitive wholesale electric markets in the United States.

PECO states that current TLR procedures allow one entity to cause the curtailment of numerous third party transactions on a regular basis to preserve power delivery in its single control area, regardless of the impact on other control areas. PECO argues that, while physical operation of the grid is maintained under these TLR procedures, reliable, inter-control area power delivery is not assured and market participants are denied fair access to the grid.

Tampa Electric states that, within peninsular Florida, transmission users must often go to several individual transmission providers and OASIS nodes, sign multiple agreements with various providers and attempt to piece together and navigate through various partial paths to connect a power sale to a buyer. Tampa Electric concludes that access to transmission services within this region is not as open as it could be to facilitate an efficient, robust wholesale market.

AEP states that coordination that previously existed in a fully integrated electric system of the construction of new generation and transmission facilities has eroded due to the separation of these functions. AEP states that congestion constraints could potentially inhibit the development of additional generation capacity or provide a disincentive to add generating capacity where needed. AEP also notes that the priorities of state regulatory agencies sometimes favor the needs of native load customers that can create conflicts among competing interest at the regional level. AEP also states that developers of new merchant generation plants have become less willing to share their long-term planning goals with transmission owners due to the business strategies that accompany a more competitive power market. However, AEP argues that removal of pancaking is not consistent with economic efficiency and may distort future transmission expansion because the cost of transmission should be based on distance and location.[80]

Several commenters state that needed transmission expansion is not taking place because of a lack of pricing incentives to build new transmission.[81] EPRI states that failure to satisfy grid expansion needs is resulting in increasing frequency and duration of power disturbances and outages costing $50 billion per year.

WPPI points out that transmission planning must be undertaken on a regional, not a state basis, noting that import capability from MAPP into Wisconsin is sometimes constrained by facilities located outside of Wisconsin, *e.g.,* transformers and lines located in Illinois and Minnesota. On the other hand, Allegheny asserts that the industry has not failed to plan and coordinate on a regional basis and cites examples of study groups and planning committees, such as VEM (Virginia-ECAR-MAAC) and GAPP (General Agreement on Parallel Paths).

Most commenters assert that pancaked transmission access charges prevent efficient access to regional markets and distort the generation market.[82] A few commenters, however, question the benefits associated with eliminating rate pancaking. Southern Company observes that the severity of pancaking effects may vary from region to region.[83]

Continuing Opportunities for Undue Discrimination. Comments dealing with continuing opportunities for undue discrimination fall generally into two camps. On the one side, transmission customers and some transmission providers agree with the NOPR's premise that opportunities for discrimination exist, that perceptions of discrimination are also a serious impediment to competitive bulk power markets, and that functional unbundling does not reflect the optimal long-term regulatory solution.[84] On the other side,

[79] EPSA specifically points to the SERC as a region where ''state commissions and utilities may be arguing that they don't 'need' RTOs to promote competitive markets,'' at a time when Southeastern markets trail the rest of the nation in proposed merchant plant development and power trading, ''both hallmarks of robust wholesale competition and workable open access policies.'' EPSA notes that SERC is the largest NERC region, both in load and peak demand, yet SERC and FRCC together constitute only 5.2 percent of the wholesale power trades nationwide.

[80] AEP at 1, and Attachment to AEP's comments (Statement of Paul Moul). As discussed in the Transmission Ratemaking section (Section G), elimination of pancaked rates (multiple access charges assessed only because the transaction crosses a corporate boundary) does not constitute a prohibition on distance sensitive rates.

[81] *See, e.g.,* Transmission ISO Participants, H.Q. Energy Services, Powerex.

[82] *See, e.g.,* FMPA, IMEA, NECPUC, Ohio Commission, Texas Commission, American Forest, Arkansas Cities, East Texas Cooperatives, Oglethorpe, PNGC, Powerex, Williams, WPSC.

[83] For illustration, Southern Company points out that a customer in its service area can transmit power 500 miles away for $3/MWh whereas a customer wanting to transmit power from Boston to Washington, DC (also a distance of 500 miles) will have to go through the three PJM, New England and NY ISOs and pay a total of approximately $14/MWh.

[84] *E.g.,* American Forest, Los Angeles, TAPS, UAMPS, Steel Dynamics, Turlock, Cinergy, Statoil, WPPI, NJBUS, MidAmerican, LG&E, Clarksdale, Michigan Commission, New Smyrna Beach,

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a number of transmission providers disagree with these premises.[85]

Comments Asserting That Discrimination Still Exists. AMP-Ohio points to an event last summer when it was unable to transmit power from a generator on AEP's system to a load on the FirstEnergy system and was forced to purchase power from FirstEnergy at $4000/MWh. AMP-Ohio contends that AEP and FirstEnergy were simultaneously reporting zero ATC during the hour, *i.e.,* an event that cannot be rationalized by AMP-Ohio (*i.e.,* an interface that is fully loaded in both directions at the same time would, in AMP-Ohio's view, cancel out).

UAMPS argues that three transmission owners that jointly own segments of a single transmission line have avoided releasing the capacity of this line under their open access tariffs through a series of contractual arrangements that distributes transmission rights directly to each of their merchant functions. As a result, only the transmission owners' merchant functions have the ability the schedule transmission service over the line. UAMPS contends that this example, and others, confirm the Commission's perception that the remedies mandated in Order No. 888 have not eliminated discrimination. UAMPS states that it is intuitively obvious that when the transmission function and merchant function ultimately serve the same master, neither can be truly independent.

Hogan contends that, without an efficient regional spot market and its ease of access, the problems of discrimination will persist. FTC concludes that several years of industry experience confirm the concern that discrimination remains in the provision of transmission services by utilities that continue to own both generation and transmission. FTC concludes that reliance on behavioral rules have proved to be less than ideal.

Cinergy contends that reliance on CBM by some transmission providers this summer provided their native load an unfair operational edge over network service in the import of power through interconnects that were the subject of TLR orders. Cinergy argues that the more severe impact on market efficiency is caused by the lack of information underlying the transmission provider's implementation of TLRs, and raises significant opportunities for transmission providers to use alleged reliability reasons to hide conduct actually motivated to protect their own or their affiliate's own power market. Cinergy concludes that market participants will never know the real answer because it may be impossible to prove abuse of the TLR procedures with access to information on the nature and cause of constraints and the lack of consistency in implementing TLRs across the regions. Cinergy adds that, even where there may be sufficient evidence to prove discrimination, potential complainants may fear retribution by the transmission provider, and may also be hesitant to file complaints because of the litigation costs of the complaint process and the lack of remedy for lost short-term market opportunities.

Enron/APX/Coral Power state that the following types of relatively overt, although difficult to detect, discrimination occur: (1) Offers of attractive transmission service to a transmission owner's affiliate or merchant function that are not similarly offered to others; (2) advance notification to the affiliate or merchant function of the availability of transmission service or the availability of a new service; and (3) changes in procedures, such as scheduling deadlines, for obtaining transmission service in ways that benefit the affiliate or merchant function. Enron/APX/Coral Power (as well as CCEM/ELCON, UtiliCorp and EPSA) also argue that a ''principal form of discrimination grows out of the exemption from the *pro forma* OATT and OASIS that is enjoyed by transmission bundled with service to captive 'native-load' customers.'' Enron/APX/Coral Power believes that, if the Commission were to conduct an investigation of compliance with the Commission's open access requirements and the uses of their own transmission system during periods of extreme peak loads and volatile prices during the past summer, the Commission would uncover evidence of widespread abuses. According to Enron/APX/Coral Power, these abuses would include instances where the transmission provider imported power on a network basis, as if it were intended to service captive, native load customers, only to turn around and sell that power competitively, off-system; where scheduling requirements or deadlines were changed without adequate notice to third parties; and where ATC amounts that either were not posted or were posted in an untimely manner.

NASUCA concludes that, despite Order No. 888, there is still reason for concern that continued discrimination in the provision of transmission services by vertically integrated utilities may be impeding competitive electric markets.

EPSA states that the prospect of real competition continues to be threatened by (1) arbitrary and discriminatory curtailment and line loading relief policies, and (2) needlessly complex and overly restrictive transmission planning, expansion and interconnection practices.

TAPS argues that the anticompetitive effects of allowing a subset of competitors to control essential facilities have been long recognized.[86] TAPS provides specific examples that it claims show that discrimination exists: (1) The price spikes in June 1998 and Summer of 1999 where the asserted ATC was inadequate to allow external generation resources to meet the needs of the market; (2) failure of a transmission owner to provide necessary upgrades; and (3) a transmission owner taking negotiating positions contrary to a clear provision of the Open Access Transmission Tariff (OATT). In its reply comments, TAPS describes a recent situation where AEP, acting in its role as the NERC Security Coordinator, informed IMPA that it had implemented a TLR seven minutes earlier, too late for IMPA to replace the curtailed schedule with another transaction at market prices, which were $35/MWh. TAPS contends that IMPA had no effective choice but to make up the shortfall by purchasing emergency energy from AEP at $100/MWh. In following hours that day, IMPA elected to purchase power from AEP at $35/MWh rather than continue its other purchase options (at $17/MWh) and risk further curtailments. TAPS observes that AEP substantially profited from delayed communication of the TLR, by selling power to IMPA at nearly three times the then-market price. TAPS states that, even assuming AEP was acting properly on this occasion, this example illustrates the inherent conflict of interest in combining security coordinator functions with that of market participant. TAPS argues that this diminishes the faith in the market place and breeds mistrust. Based on the examples it provides and on the evidence reviewed in the NOPR, TAPS

Industrial Consumers, IMPA, First Rochdale, East Texas Cooperatives, FMPA, TDU Systems, Canada DNR, Allegheny, IMEA, Sonat, Public Citizen, EPSA, CCEM/ELCON, UtiliCorp and FTC. [85]:United Illuminating, Southern Company, MidAmerican, Duke, PSE&G, FP&L, Entergy, FirstEnergy, Alliance Companies, Lenard and Florida Power Corp.

[85] United Illuminating, Southern Company, MidAmerican, Duke, PSE7G, FP&L, Entergy, First Energy, Alliance Companies, Lenard and Florida Power Corp.

[86] TAPS cites to a 1912 Supreme Court case involving the control of a railway terminal by several railroads which their competitors were required to use. *See* United States v. Terminal RR Ass'n, 224 U.S. 383, 397 (1912).

recommends that the Final Rule make formal findings that undue discrimination remains widespread throughout the industry.

Steel Dynamics states that the Commission needs to build confidence that transmission customers will not be victimized when markets get tight and claims the Commission's record to date has been uneven. Steel Dynamics cites a case in which the Commission determined that Niagara Mohawk Power Corporation had committed several violations of the OASIS posting requirements and standards of conduct in order to favor its marketing affiliate over a third-party user.

Clarksdale states that it has experienced problems with the posting of ATC by Entergy on the OASIS. Clarksdale states that on July 21, 1999, it attempted to purchase from Cajun Electric Cooperative 20 MW of power for whatever length of time that Cajun would have had it available up to one week. Entergy denied the transaction on the basis that the ATC between Entergy and Cajun was zero. Clarksdale complained and the next day the ATC for this interface was shown to be 1,700 megawatts; however, by that time Cajun had sold the power to another entity and it was no longer available for Clarksdale. Clarksdale submits that the incident, along with others Clarksdale reported, compels the conclusion that the function of security coordination should be entirely separate from the transmission owner and from the generation owner and that participation in an absolutely independent RTO should be mandated by the Commission in the final rule.

FMPA states that, whether because of discriminatory motivations or simply because of balkanized perspectives (or both), there have been numerous instances of Florida's dominant transmission owners falling short on the transmission planning performance. According to FMPA, Florida's dominant transmission owners have failed to promptly address regionally significant constraints (until addressing them became advantageous for their own merchant function), and have continued to impose discriminatory transmission-related construction requirements. FMPA claims that relying on functional separation rules to curb the self interest of market-interested transmitters when huge sums of money are at stake is like ''relying on words to hold back the tide.'' [87]

WPPI states that it routinely experiences and observes subtle and difficult to detect problems in the marketplace. WPPI states that, because they are subtle and difficult to detect, they are not susceptible to any prompt and effective regulatory remedy. WPPI adds that prosecution of complaints is expensive and time consuming and customers do not have the ability to prosecute each such incident.

WPPI contends that transmission owners are able to dispatch their resources in order to manipulate their exposure to TLRs, while customers cannot. WPPI characterizes this tactic as a ''shell game'' because it is purportedly accomplished by designating fictional sources and sinks and treating one transaction as two separate transactions. WPPI contends that these actions leave other transmission users to bear the costs of curtailments and denials of service. WPPI argues that these manipulations of TLRs are ''rampant.''

WPPI states that during summer peak periods, when it claims power prices exceeded $5,000/MWh in the Eastern Interconnection, at least one Midwestern transmission-owning utility appears to have been able to abuse its control-area operator authority to gain a market advantage. According to WPPI, as a control-area operator, the transmission owner at issue declared that power shortages had created an emergency situation which allowed it to relax the transmission limitations that it had imposed on other market participants, enabling the transmission owner to acquire less expensive power from the MAPP region. WPPI claims that the transmission owner thereby gained a market advantage, at a time when market advantages were worth huge sums. WPPI claims that most if not all other control-area operators in the region played by the rules and did not abuse the system to access less expensive power for which ATC ostensibly was not available. WPPI asserts that utilities that are not control-area operators had no choice other than to buy high cost, locally generated power, and that they ''lack not only the right, but also the might'' [88] to declare an emergency or to recalculate ATC to help themselves. WPPI and Cinergy maintain that this recent event provides a clear example of the continuing potential, under present industry structure, for vertically integrated utilities to abuse their transmission control to gain market advantages and for that reason, among others, the Commission should mandate that entities under its jurisdiction participate in RTOs.

TDU Systems provide a number of examples which raise their concerns about undue discrimination, including: (1) Failure of an incumbent IOU to reduce its own out-of-region power sales during a period when the system was experiencing overloads and the transactions of other transmission users were jeopardized; (2) overly aggressive and selective enforcement of tariff requirements on transmission customers than are imposed on the transmission providers' own merchant function; (3) selectively targeting generating units that are jointly owned by competitors when redispatch of the transmission system is required to relieve line loading; (4) self-serving ATC calculations in circumstances when transmission customers have no way of knowing whether access is being denied legitimately or through manipulation for competitive gain; and (5) onerous and lengthy negotiations to obtain system studies. TDU Systems contend that there is a fire under the smoke of allegations of discrimination, and those complaining of the anecdotal nature of its information haven't provided any evidence to show that discrimination is not occurring.

TXU Electric states that, if a truly successful, restructured competitive electric industry is to achieve its full potential, it is incumbent of all concerned, transmission providers, users and regulators alike, to move beyond the impediments of the past, including hidden motivations on the part of some, unfounded fears of hidden motivations on the part of others, and a general environment of distrust. TXU Electric adds that, transmission users and regulators must have confidence that the transmission grid is truly an open, non-discriminatory and robust commercial highway and transmission providers must inspire that confidence. TXU Electric concludes that the Commission's voluntary collaborative approach is an important step in the right direction.

LG&E states that, under the current system, transmission owners' operational decisions, even if well intentioned, are surrounded by a cloud of suspicion that, acting in the name of reliability, the transmission owner has enhanced its position in the generation market. LG&E agrees that this perception that the transmission system is not being operated in an even handed manner undermines confidence in the non-discriminatory open access implemented under Order No. 888.

Virginia Commission agrees that allegations of discrimination represent only known problems, and there may be many unknown ones remaining given that it is difficult for transmission users

[87] FMPA at 23–24.

[88] WPPI at 31.

to identify and demonstrate instances of discrimination.

Canada DNR states that discriminatory behavior by transmission operators, identified in the NOPR as the second significant driver for establishment of RTOs, is not perceived as a key impediment to the evolution of efficient bulk power markets in Canada.

Dynegy argues that transmission provides have the incentive and ability to discriminate in today's markets due to the combination of control over transmission with participation in power markets and the existing regulatory structure that exempts transmission providers from the open access rules of Order Nos. 888 and 889 for its bundled, native load customers. Dynegy argues that the ''native load'' exemption can be and is often manipulated to favor the transmission providers' own or affiliated merchant functions.

PECO notes that, in their capacity as vertically integrated utilities, transmission providers have access to critical market sensitive information with respect to each transaction (*e.g.,* source, sink), at a time when they are in direct competition in the same markets and with the same transmission customers whose market information they have. PECO argues that, in spite of the existence of functional unbundling and codes of conduct, the serious potential for conflicts of interest and abuse inherent in the current structure cannot be ignored.

Comments Asserting That Discrimination Is Not a Problem. A number of commenters, mostly transmission owners, do not believe that significant discrimination problems remain with respect to wholesale transmission access pursuant to Order No. 888. As a general matter, those transmission owners whose actions are cited in other pleadings as examples of undue discrimination disagree with those characterizations of the cited events and declare that they provide non-discriminatory transmission service under their OATT. These transmission owners contend that the disputes cited in the pleadings are not the result of discriminatory practices; rather, they are the result of the priority accorded native load customers under the OATT, and good faith errors on the part of the transmission provider trying to administer complex rules and tariff changes that have necessitated fundamental changes to the structure of companies and the way they do business.

EEI contends that many of the difficulties transmission customers encounter in obtaining price, availability and transmission service result in a technology gap that can be, and often is, interpreted as discriminatory behavior. EEI also contends that many allegations of discrimination are ''rooted at their heart'' on the scarcity of transmission resources and not overt attempts to discriminate against specific customers.

PSE&G argues that supposition and anecdotal evidence of alleged abuses by transmission owners does not justify a radical change in the existing regulatory scheme. PSE&G contends that, while the incentive to maximize shareholder value is certainly a powerful force in the marketplace, the requirements of law, such as Order Nos. 888 and 889, will prevail.

Duke argues that mere anecdotes of discrimination, involving unnamed parties and without reference to specific facts, are not evidence of anything, let alone discrimination, and cannot form the basis of a reasoned decision. Duke also lists a number of formal complaint proceedings where the Commission found the transmission provider to have acted properly. Entergy argues that those alleging discrimination, as competitors of transmission providers, have an economic incentive to make their own allegations. Entergy adds that, if perceptions of discrimination were impeding competitive markets, there would not be 20,000 MW of generation investment proposed in its region.

United Illuminating complains that many of the allegations of undue discrimination presuppose that all utilities are the same, *i.e.,* vertically integrated transmission, distribution and generation companies, and do not recognize that a number of utilities are divesting their generation business.

Southern Company states that the goal of non-discriminatory transmission service is already being satisfied in the Southeast. Southern Company asserts that it has separated its transmission and reliability functions from its wholesale merchant function up to the level of ''very senior management.'' Southern Company submits that it is unaware of any pending allegations of discrimination against it. Southern Company adds that the Southeast is characterized by large transmission systems such as Southern Company, Tennessee Valley Authority, and Entergy and that these transmission systems are already planned and operated on a regional basis. Southern Company also points out that it alone covers a region as large as (if not larger than) many ISOs currently in existence. Under these circumstances, Southern Company believes that the Commission's open access initiatives have worked in the Southeast and that additional steps are not required to ensure non-discriminatory transmission service.

MidAmerican asserts that complaints received by the Commission about alleged discrimination should not be the primary basis for determining if the market is successful. According to MidAmerican, if it is assumed that an adequate number of parties are competing successfully, it could be concluded that the complaints may be indications of ill-defined problems not yet resolved, isolated market flaws, or indications of a successful market with somewhat inadequate tools.

Duke believes that its transmission organization is meeting the needs of its customers as evidenced by the very few and relatively insignificant complaints Duke has received regarding the administration of its OATT. Duke believes that Order No. 888 has been quite successful and, although it agrees with the Commission that elimination of balkanized transmission operations through the formation of larger, regional operations is ultimately preferred, Duke does not believe Order No. 888 should be abandoned hastily.

Duke argues that disputes are primarily the result of the complexity of the priority scheme in the Commission's *pro forma* tariff, the rules for which are still being developed; the inherent tension between the Commission's comparability requirement and the requirements of state-regulated native load customers; and the obligation to ensure reliability of the transmission grid on a real time basis. Duke asserts that the vast majority of transactions occurring as a result of Order No. 888 do not produce transmission disputes and, to the extent that isolated instances of discrimination have occurred, the Commission has adequate authority to address the problem.

Duke also maintains that a major source of confusion involves the rights of native load customers versus wholesale transmission users under the *pro forma* tariff and that this issue remains subject to disagreement and needs further clarification. Duke says its conclusion is reinforced by its experience as a market participant in areas where there are ISOs. Duke asserts that the establishment of ISOs in California, NEPOOL and PJM has not resulted in the elimination of disputes over tariff ambiguities. Duke questions the assertion that disagreements between customers and individual transmission owners are indicative of significant ongoing discrimination.

Florida Power Corp. and FP&L's comments are similar to Duke's. Florida

Power Corp. and FP&L state that they have not received any formal complaints alleging undue discrimination with regard to their OATT. Florida Power Corp. and FP&L agree that the increasing number of transactions has led to a concomitant increase in transmission disputes; however, they characterize the disputes as legitimate disagreements over policy or meaning of the *pro forma* tariff as opposed to true allegations of discriminatory conduct. Like Duke, Florida Power Corp. and FP&L believe that many of the allegations of potentially discriminatory conduct are attributable to two primary areas: (1) Rights of native load customers versus wholesale wheeling customers; and (2) disputes arising from the complex priority scheme in the *pro forma* tariff. According to FP&L, disputes will still occur until the issues relating to priority rights are resolved. FP&L argues that the Commission cannot expect that any remedy will eliminate discrimination claims in light of the Eighth Circuit Court's decision in *Northern States Power Co.* v. *FERC*.[89]

FPL and Florida Power Corp. argue that unsubstantiated allegations do not constitute evidence of discrimination and should be characterized as legitimate disputes over tariff interpretation, while EEI describes some of the allegations as ''one-sided characterizations of cases now being litigated.'' FPL also contends that some intervenors adopt the stance that, whenever the transmission provider and customer are in disagreement, it evidences discrimination. Florida Power Corp. states that, if undue discrimination exists outside of Florida, it is a function of the newness of the Commission's open access rules, and it is far too soon to declare functional unbundling ineffective. Florida Power Corp. agrees with the Commission's statement that it may be impossible to distinguish an inaccurate ATC presented in good faith from an inaccurate ATC posted for the purpose of favoring the transmission provider's marketing interests, but concludes that, once technical issues have been resolved about ATC calculations, the volume of disputes will be greatly diminished. Florida Power Corp. adds that there is no evidence of a pattern of industry-wide undue discrimination, and concludes that mere perceptions cannot provide a justification for generic remedial action.

Entergy, FirstEnergy, Alliance Companies and Lenard argue that there is no credible or substantial evidence in the record that transmission owners have been engaging in discriminatory practices in providing transmission services under Order Nos. 888 and 889 and, therefore, the Commission should not, and lawfully cannot, rely on mere allegations of discriminatory conduct. FirstEnergy states that it has doubled its control area reservation and back office staff to handle the five percent of its transmission business that is wholesale related and still is having difficulty keeping pace with OASIS and tagging administrative processes. FirstEnergy asserts that due to relatively new processes associated with open access transmission, there are often good faith disputes over the proper interpretation of the Commission's requirements and these disputes should not be mischaracterized as continued discrimination.

Commission Conclusion. Engineering and Economic Inefficiencies. In this Final Rule, we affirm our preliminary determination that the engineering and economic inefficiencies identified in the NOPR[90] are present in the operation, planning and expansion of regional transmission grids, and that they may affect electric system reliability and impede the growth of fully competitive bulk power markets. The sources of these inefficiencies involve: difficulty determining ATC; parallel path flows; the limited scope of available information and the use of non-market approaches to managing transmission congestion; planning and investing in new transmission facilities; pancaking of transmission access charges; the absence of clear transmission rights; the absence of secondary markets in transmission service; and the possible disincentives created by the level and structure of transmission rates. Virtually all commenters agree that at least some of these inefficiencies exist. There is substantial agreement among commenters that most of the engineering and economic obstacles identified by the NOPR arise from the current industry structure and can be rectified through development of regional transmission entities.

As noted by Allegheny, the industry historically has done an excellent job of regional coordination in implementing voluntary standards to maintain the security of the transmission system through various study groups and planning committees. However, virtually all commenters agree that new competitive pressures are interfering with the use of traditional methods of coordinated regional transmission planning. As a result, new transmission additions that will benefit reliable grid operations are being delayed. Some commenters state that the increasing frequency and duration of power outages have cost the economy billions of dollars, and they predict that unless this problem is addressed now the reliability of power supply will worsen. The traditional use of regional coordination through study groups and planning committees is no longer effective because these entities are usually not vested with the broad decisionmaking authority needed to address larger issues that affect an entire region, including managing congestion, planning and investing in new transmission facilities, pancaking of transmission access charges, the absence of secondary markets in transmission service, and the possible disincentives created by the level and structure of transmission rates.

We recognize, as some commenters point out, that the degree to which these inefficiencies act as obstacles to electric competition and reliability varies from system to system. However, we believe it is clear that such inefficiencies exist and are sufficiently widespread that they must be addressed to prevent them from interfering with reliability and competitive electricity markets.

Continuing Opportunities for Undue Discrimination. As noted, many transmission customers and some transmission providers argue that there are continuing opportunities for undue discrimination under the existing functional unbundling approach. A number of the commenters provide examples of events that, in their view, indicate that transmission owners are engaging in undue discrimination. These commenters also generally believe that even the perception of undue discrimination is a significant impediment to the evolution of competitive electricity markets. A number of transmission providers challenge the relevancy of these examples, characterizing them as unsubstantiated or anecdotal allegations that do not rise to the level of evidence of undue discrimination necessary to support generic action. These transmission providers further contend that many disputes simply reflect good faith efforts of transmission providers to interpret the Commission's pro forma tariff and standards of conduct. These

[89] *See* Northern States Power Co. (Minnesota) and Northern States Power Co. (Wisconsin), 83 FERC ¶ 61,098, *clarified,* 83 FERC ¶ 61,338, *reh'g, clarification and stay denied,* 84 FERC ¶ 61,128 (1998), *remanded,* Northern States Power Co., *et al.* v. FERC, 176 F.3d 1090 (8th Cir. 1999), *reh'g denied* (unpublished order dated Sept. 1, 1999), *order on remand,* 89 FERC ¶ 61,178 (1999) (request to withdraw curtailment procedures pending) (*Northern States*).

[90] FERC Stats. & Regs. ¶ 32,541 at 33,697.

commenters also generally share the view that the Commission should not base its decisions in this rule on mere perceptions that may be prevalent in the industry.

For the most part, the challenges mounted by these commenters are focused against a determination by the Commission that it should mandate participation in RTOs in this Rule. As noted in Section C.1 of this Rule, we have also determined that a measured and appropriate response to the evidence presented and concerns raised is to adopt a voluntary approach to the formation of RTOs. However, as discussed below, we do conclude that opportunities for undue discrimination continue to exist that may not be remedied adequately by functional unbundling. We further conclude that perceptions of undue discrimination can also impede the development of efficient and competitive electric markets. These concerns, in addition to the economic and engineering impediments affecting reliability, operational efficiency and competition, provide the basis for issuing this Final Rule.

At the outset, it is important to note that the conclusion that there are continuing opportunities for undue discrimination should not be construed as a finding that particular utilities, or individuals within those utilities, are acting in bad faith or deliberately violating our open access requirements or standards of conduct. However, we cannot ignore the fact that the vertically integrated structure reflected in the industry today was created to support the business objectives of a franchised monopoly service provider that owned and operated generation, transmission and distribution facilities primarily to serve requirements customers at wholesale and retail in a non-competitive environment. Clearly, there are aspects of this vertically integrated structure that are difficult to transition into a competitive market. As we noted in the NOPR and Order No. 888, vertically integrated utilities have the incentive and the opportunity to favor their generation interests over those of their competitors. If a transmission provider's marketing interests have favorable access to transmission system information or receive more favorable treatment of their transmission requests, this obviously creates a disadvantage for market competitors.

While we have attempted to rely on functional unbundling to address our concerns about undue discrimination, there are indications that this is difficult for transmission providers to implement and difficult for the market and the Commission to monitor and police. In cases in which the Commission has issued formal orders, we have found serious concerns with functional separation and improper information sharing with respect to at least four public utilities.[91] In addition, our enforcement staff is receiving an increasing number of telephone calls about standards of conduct issues, ranging from simple questions about what is permissible conduct to more serious complaints alleging actual violations of the standards of conduct. In a number of cases, our staff has verified non-compliance with the standards of conduct.[92] The petitioners for rulemaking in Docket No. RM98–5–000 allege that there are common instances of ''unauthorized exchanges of competitively valuable information on reservations and schedules between transmission system operators and their own or affiliated merchant operation employees.''[93] They also cite OASIS data showing an instance where a transmission provider quickly confirmed requests for firm transmission service by an affiliate, while service requests from independent marketers took much longer to approve. We believe that some of the identified standards of conduct violations are transitional issues resulting from a new way of doing business, and we acknowledge that many utilities are making good-faith efforts to properly implement standards of conduct. However, we also believe that there is great potential for standards of conduct violations that will never even be reported or detected. Moreover, as we stated in the NOPR,[94] we are increasingly concerned about the extensive regulatory oversight and administrative burdens that have resulted from policing compliance with standards of conduct. The use of standards of conduct is not the best way to correct vertical integration problems. Their use may be unnecessary in a better structured market where operational control and responsibility for the transmission system is structurally separated from the merchant generation function of owners of transmission.

We also cannot dismiss the significance of reports of undue discrimination simply because they are not reduced to formal complaints. As many intervenors have asserted, the cost and time required to pursue legal channels to prove discrimination will often provide an inadequate remedy because, among other things, the competition may have already been lost.[95] The fact that evidence of discrimination in the fast-paced marketplace is not systematic or complete is not unexpected. The fact remains that claims of undue discrimination have not diminished, and there is no evidence that discrimination is becoming a non-issue.

Finally, we continue to believe that perceptions of discrimination are significant impediments to competitive markets. Efficient and competitive markets will develop only if market participants have confidence that the system is administered fairly.[96] Lack of market confidence resulting from the perception of discrimination is not mere rhetoric. It has real-world consequences for market participants and consumers. As stated by NERC, there is a reluctance on the part of market participants to share operational real-time and planning data with transmission providers because of the suspicion that they could be providing an advantage to their affiliated marketing groups,[97] and this can, in turn, impair the reliability

[91] *See Wisconsin Public Power Inc. SYSTEM* v. *Wisconsin Public Service Corporation,* 83 FERC ¶ 61,198 at 61,855, 61,860, *order on reh'g,* 84 FERC ¶ 61,120 (1998) (WPSC's actions raised ''serious concerns'' as to functional separation; WP&L's actions demonstrated that it provided unduly preferential treatment to its merchant function); Washington Water Power Co., 83 FERC ¶ 61,097 at 61,463, *further order,* 83 FERC ¶ 61,282 (1998) (utility found to have violated standards in connection with its marketing affiliate); Utah Associated Municipal Power Systems v. PacifiCorp, 87 FERC ¶ 61,044 (1999) (finding that PacifiCorp had failed to maintain functional separation between merchant and transmission functions).

[92] *See, e.g.,* Communications of Market Information Between Affiliates, Docket No. IN99–2–000, 87 FERC ¶ 61,012 (1999) (Commission issued declaratory order based on hotline complaint clarifying that it is an undue preference in violation of section 205 of the FPA for a public utility to tell an affiliate to look for a marketing offer prior to posting the offer publicly).

[93] Petition at 15.

[94] FERC Stats. & Regs. ¶ 32,541 at 33,711–12.

[95] For example, EPSA has told us: ''Furthermore, even if the exercise of such discrimination could be adequately documented and packaged in the form of a complaint under section 206 of the Federal Power Act under a more streamlined complaint process contemplated by the Commission, it would still be extremely costly and inefficient to deal with such complaints on a case-by-case basis. More than likely, the potential power transactions for which transmission principally was sought would disappear by the time a Commission ruling was obtained. Motion to Intervene and Comments of Electric Power Supply Association in Support of Petition for Rulemaking, Docket No. RM98–5–000 (filed Sept. 21, 1998), at 3.''

[96] For example, a representative of Blue Ridge told us: ''There simply is no shaking the notion that integrated generation and transmission-owning utilities have strategic and competitive interests to consider when addressing transmission constraints. Functional unbundling and enforcement of [standard of] conduct standards require herculean policing efforts, and they are not practical.'' Regional ISO Conference (Richmond), Transcript at 20.

[97] NERC Reliability Assessment 1998–2007, at 39.

of the nation's electric systems. Lack of market confidence may deter generation expansion, leading to higher consumer prices. Fears of discriminatory curtailment may deter access to existing generation or deter entry by new sources of generation that would otherwise mitigate price spikes of the type that have been experienced during peak periods in the last two summer peak periods. Mistrust of ATC calculations will cause transactions involving regional markets to be viewed as more risky and will unnecessarily constrain the market area, thereby reducing competition and raising prices for consumers. The perception that a transmission provider's power sales are more reliable may provide subtle competitive advantages in wholesale markets, *e.g.,* purchasers may favor sales by the transmission provider or its affiliate, expecting greater transmission service reliability. We believe that the potential for such problems increases in a competitive environment unless the market can be made structurally efficient and transparent with respect to information, and equitable in its treatment of competing participants.

In summary, we affirm our conclusion in the NOPR that economic and engineering inefficiencies and the continuing opportunity for undue discrimination are impeding competitive markets. As noted below, we conclude that RTOs will remedy these impediments and that it is essential for the Commission to issue this Final Rule.

B. Benefits That RTOs Can Offer to Address Remaining Barriers and Impediments

In the NOPR the Commission explained how the use of independent RTOs could help eliminate the opportunity for unduly discriminatory practices by transmission providers, restore the trust among competitors that all are playing by the same rules, and reduce the need for overly intrusive regulatory oversight.[98] The Commission further identified a number of significant benefits of establishing RTOs: (1) RTOs would improve efficiencies in the management of the transmission grid;[99] (2) RTOs would improve grid reliability; (3) RTOs would remove opportunities for discriminatory transmission practices; (4) RTOs would result in improved market performance; and (5) RTOs would facilitate lighter-handed governmental regulation.[100] The Commission requested comments on the benefits of RTOs and the magnitude of these benefits.

Comments. Description of Benefits. Many commenters support the establishment of RTOs throughout the United States to effectively remove the remaining impediments to competition in the power markets.[101] Illinois Commission states that the pursuit of competition as the driving force for markets in the electric industry requires developing new institutions and accepting new practices, and RTOs are the logical next organizational step in the electric industry restructuring process. Entergy agrees that significant benefits can be achieved by the creation of properly-structured, large RTOs and that the Commission has accurately described many of those benefits in the NOPR. Ohio Commission believes that a properly structured RTO will facilitate efficient regional generation markets, while preventing incumbent holding companies from improperly exercising their market power.

PG&E acknowledges that the benefits of Order No. 888 have been largely reaped, and still significant impediments to an efficient competitive marketplace remain in place where RTOs are not yet operational. Moreover, industry restructuring has led to new and complex operational issues that were unanticipated at the time Order No. 888 was issued. RTOs represent the most promising and efficient regulatory method for the Commission to address these issues. Without RTOs, it would be incumbent on the Commission to take very detailed and intrusive actions because the transmission grid cannot operate reliably and efficiently unless the competitive and operational issues are resolved.

Ontario Power agrees that the electric power industry should now move beyond the functional unbundling approach prescribed in Order Nos. 888 and 889. TDU Systems asserts that wholesale electric markets will benefit immensely if RTOs can simply provide transmission service on an unbiased basis, treating all customers fairly, and take the lead role in regional transmission planning.

On the other hand, a number of vertically integrated utilities do not support government action to form RTOs. For example, Duke recognizes that there may be transmission functions performed today within individual company control centers, within existing control areas, or within existing reliability councils that may be better and/or more efficiently performed by a regional transmission organization. However, Duke also believes that the industry is voluntarily working to identify such functions or processes and is effecting meaningful changes and improvements in a timely manner. Accordingly, Duke believes that this progress should not be pre-empted by regulatory mandates, and that there are insufficient data, at this time, to draw meaningful conclusions regarding the magnitude of benefits that will result from RTO formation.

Similarly, MidAmerican argues that benefits of RTOs can be realized without RTOs. MidAmerican claims that existing regional organizations, such as MAPP, are capable of meeting the Commission's concerns about eliminating existing impediments to an efficient competitive marketplace. FP&L states that the NOPR does not attempt to quantify any of the claimed benefits of RTOs. FP&L is unaware of any data that specifically and objectively show that ISOs have saved ratepayers money in those areas where ISOs have been established. Nor is it aware of any specific quantification of any other actual or projected benefits of ISOs.

Some commenters contend that the costs of establishing RTOs must not exceed the benefits. Cal DWR argues that significant start-up costs and costs associated with duplicative efforts have been higher than the NOPR appears to recognize. These costs entail not only costs of the new organization itself, but also market participants' costs in travel, staffing, and other expenses and investments necessary to participate or operate in new structures. Other commenters suggest that each proposal contained in the NOPR should be carefully evaluated for its cost consequences.[102]

Seattle notes that its region has the lowest cost electricity in the Nation and an already thriving wholesale market with little price volatility. Assuming that an RTO is projected to result in additional transmission costs, Northwest consumers will be less willing to incur these costs than consumers in regions where power costs are high and wholesale prices are extremely volatile. Snohomish and Aluminum Companies assert that one of fatal flaws of the IndeGO proposal[103] was that its demonstrable benefits did

[98] FERC Stats. & Regs. ¶ 32,541 at 33,714.

[99] These efficiencies include, among other things, regional transmission pricing, improved congestion management of the grid, more accurate ATC calculations, more effective management of parallel path flows, reduced transaction costs, and facilitation of state retail access programs.

[100] FERC Stats. & Regs. ¶ 32,541 at 33,716–20.

[101] *See, e.g.,* PJM, DOE, Illinois Commission.

[102] *See, e.g.,* Cal DWR, California Board, Southern Company, Aluminum Companies.

[103] IndeGO is an independent grid operator proposal that has been discussed for the Pacific Northwest and Rocky Mountain area.

not clearly outweigh the costs of its start-up and operation. Snohomish requests that the Commission not impose an RTO with similar flaws upon the Northwest. A number of commenters also urge the Commission to reject any RTO filing for the Northwest or other regions that fails to provide a strong demonstration that its benefits will substantially outweigh its projected costs.[104]

To ensure that RTOs are formed in a cost effective and efficient manner, SRP proposes a phased approach to RTO development that would allow RTOs to gradually take on new functions and responsibilities in response to the needs to the market. In addition, the Commission should require RTOs to establish criteria against which they will measure cost effectiveness and efficient performance and to make adjustments where criteria are not being met.

Canada DNR states that structural differences between the Canadian and American electric power industries mean that there may be fewer potential benefits from the formation of RTOs in Canada than those identified by the Commission for the United States. Consequently, it believes that Canadian jurisdiction should be able to assess the costs and benefits of RTO proposals. In addition, it notes that some may find that, although the benefits do warrant the associated costs, they may address impediments to efficient electricity markets through other means.

Comments on RTOs Improving Efficiencies in the Management of the Transmission Grid.[105] PJM agrees with the Commission that placing as many grid management functions as possible under an RTO is the best means of bringing the benefits of RTOs to the marketplace. A number of commenters address specific RTO actions as examples of grid management efficiencies, including use of regional transmission pricing, accurate estimation of ATC, efficient planning for grid expansion, and facilitating state retail access programs.

FMPA claims that a just and reasonable RTO transmission rate, with a unified regional loss factor or factors, would provide a regionally rational approach, which is not provided by the existing fragmented regime. Pancaking has long prevented FMPA and its members located on the Florida Power Corp. transmission system from economically delivering the output from their portions of the St. Lucie nuclear plant to their loads. Similarly, WPSC notes that without an RTO that encompasses the Midwest region, unjustified pancaked transmission rates may inhibit the efficient flow of power across the region.

PacifiCorp supports the Commission goal of eliminating transmission pancaking, to the extent practical. PacifiCorp maintains that such a goal could be furthered by the creation of the most geographically expansive RTOs that are technically workable. The goal also could be met, however, if multiple RTOs within the western United States agree to reciprocally eliminate charges in connection with the ‘‘export’’ or ‘‘import’’ of power from one RTO to another. In the western United States, such ‘‘reciprocity’’ agreements may be preferable to the creation of a single RTO that otherwise is too large to be efficient, safe and reliable, or of a single RTO for which operating principles must be unreasonably compromised to attract all necessary transmission owners.

Allegheny asserts that even with an RTO, grid inefficiencies such as rate pancaking and congestion will continue unless an appropriate pricing mechanism is adopted. The various RTO structures, regardless of size and number, would still need to work cooperatively to ensure that the various interfaces are sufficient to maintain the reliable operation of the system. The formation of an RTO, by itself, does not bring a particular benefit.

Rochdale asserts that a properly structured independent RTO, with a broad geographic scope, could eliminate incorrect calculations of ATC and TTC. Furthermore, the motive for discrimination and possible manipulation that exists where transmission owners with affiliated power marketers are responsible for reporting ATC and TTC would become moot. FMPA contends that, without an RTO, most market participants would remain unable to replicate or trust the transmission owners' ATC calculations. FMPA indicates that customers and regulators cannot properly review transmission providers' ATC accounting without access to their TTC starting points; however, existing Florida OASIS sites do not provide TTC information. In addition, ATC calculations require extensive application of engineering judgment. FMPA questions whether market-interested transmission providers can be trusted to exercise such judgment disinterestedly. Consequently, FMPA believes that an RTO could provide unbiased ATC information.

Many commenters believe that RTOs would provide more efficient planning for transmission and generation investments.[106] For example, Entergy agrees that the creation of RTOs can lead to more efficient and effective planning and expansion of the transmission system. However, to ensure efficient investment in the transmission system, Entergy proposes that the Commission encourage innovative pricing policies to replace traditional cost-of-service ratemaking in certain respects. Minnesota Power also agrees that an RTO would help identify the best place on the grid to locate new generation. It believes that the centralization of regional reliability planning is a big step forward for enabling independent power producers to build projects and also is a significant benefit to each transmission owner who deals with requests from generation groups.

Illinois Commission and Texas Commission state that electricity consumers in states adopting retail direct access can directly and fully benefit from the operation of properly constituted RTOs and their concomitant improvements in system efficiency, reliability and market competition.

Comments on RTOs Improving Grid Reliability. Many commenters agree that an RTO could provide improved reliability.[107] Minnesota Power supports the formation of a single regional body that operates the regional grid and enforces reliability rules for the entire region. It suggests that a non-profit RTO can be expected to enforce reliability rules fairly and aggressively and, thus, require minimal Commission oversight. On the other hand, a for-profit RTO may be perceived as biased towards making a profit at the expense of reliability and may require additional scrutiny by the Commission.

Michigan Commission strongly supports creating an RTO for the Midwest that is large enough to ensure reliability. It is very concerned that splitting the Midwest region into improperly sized competing ISOs, RTOs, and/or Transcos will affect regional reliability and delay the benefits of competition. Also, splitting a region into multiple RTOs reduces

[104] *See, e.g.,* Big Rivers, Chelan, California Board, Industrial Customers, Arizona Commission, EEI, Idaho Commission, Washington Commission.

[105] As noted earlier, many of the principal benefits of RTOs (*e.g.,* congestion management, improved reliability, parallel path flow resolution) are discussed in greater detail later as RTO minimum characteristics and functions; however, some of the commenters cited here mention these benefits as part of their overall discussion of RTOs improving efficiencies in the management of the transmission grid.

[106] Comments are addressed in greater detail in the discussion of planning and expansion as an RTO minimum function.

[107] Comments are addressed in greater detail in the discussion of short-term reliability as an RTO minimum characteristic.

access to economic generation due to increased transmission charges. Michigan Commission believes competition and reliability within the region will be served best if the Transmission Alliance and Midwest ISO are joined.

Comments on RTOs Removing Opportunities for Discriminatory Transmission Practices. Many commenters, mostly transmission customers, agree that RTOs will remedy continuing opportunities for undue discrimination.[108]

As both a buyer and seller of wholesale electricity, Oglethorpe supports the evolution of competitive markets for generation service. To ensure that competitive markets evolve and perform in a workable manner, market participants should be assured access to the transmission system on a fair and comparable basis, without regard to transmission ownership. It believes that true competition can occur only with widespread, open and nondiscriminatory access to the transmission system. UtiliCorp claims that removing control over access to transmission from the remaining large transmission-owning utilities and placing such control in properly structured RTOs will go a long way toward eliminating the remaining obstructions to effective competition in wholesale markets for electric power.

Virginia Commission agrees that discrimination exists and that RTOs can help facilitate competition and police non-competitive activities. However, Virginia Commission believes that it is premature to conclude that there is no role for rigorous governmental regulation. Virginia Commission urges that the Commission not rely exclusively on RTOs to detect, prevent and penalize violations of the FPA and should itself provide for expedited handling of allegations regarding discrimination and market power abuses.

On the other hand, a number of commenters, mostly transmission owners, do not believe that RTOs are needed to address undue discrimination because they do not believe that significant discrimination problems remain with respect to wholesale transmission access pursuant to Order No. 888.[109] PSE&G argues that, if a misperception exists in the marketplace as to the trustworthiness or incentives of transmission owners as a whole, it may signal a need for an industry-wide educational campaign that discusses transmission operation and system reliability. However, such a misperception does not, in and of itself, warrant altering the structure of the industry.

Comments on RTOs Resulting in Improved Market Performance. DOE asserts that open and comparable transmission access can reduce both concentration in generation markets (by expanding the boundaries of the relevant market) and the potential to discriminate through vertical control but cannot, in its view, eliminate all market power. The establishment of an independent RTO can and should substantially mitigate the potential exercise of market power through vertical control, because dispatch and related transmission services will be provided by an independent entity with no financial interest in wholesale market participants. Furthermore, the expected contribution of an RTO in reducing the risk of horizontal market power will be realized only if RTOs have sufficient ''critical mass.'' Appropriately sized RTOs are necessary to assure a transparent and fair marketplace for all generation.

EPA notes that RTOs can play an important role in the development of environmentally preferred or ''green'' electricity products for use by states that are implementing retail electricity competition. As the operator of the transmission system, an RTO will have access to detailed information on the operations of individual generators as well as fuel type and air emissions, even where such information is considered confidential. RTOs are uniquely situated to assemble the information necessary to determine environmental attributes of specific retail electricity products for purposes of consumer information disclosure. EPA notes that this is already occurring in New England, where ISO–NE has agreed to provide the states with information on environmental attributes and resource mix for individual generators. In addition to facilitating consumer information disclosure, EPA notes that this information will support other state policies, such as renewable portfolio standards and generation performance standards.

Comments on RTOs Facilitating Lighter-Handed Governmental Regulation. Although most commenters agree that properly-designed RTOs can be self-governing to a certain extent, the vast majority of commenters believe that the Commission has either overstated the reliance it should place on self-governance or has reached this conclusion prematurely. Most of these commenters suggest that there is insufficient evidence at this time to reach the conclusion that RTO formation would necessarily result in lighter-handed regulation. A number of commenters also caution that the Commission should not significantly reduce its oversight of RTOs until they are proven to be effective. British Columbia Ministry states that the structure of future RTOs should minimize additional layers of administration and oversight. However, at least one commenter, Cal DWR, noting that RTOs are themselves transmission monopolies subject to the FPA, argues that the Commission should continue its course of regulating RTOs to ensure compliance with legal and policy requirements.

PJM generally supports the Commission's conclusion regarding light-handed regulation. It notes that, where ISOs' decisions are independent and conducted through an extensive stakeholder processes to produce collaborative solutions to market issues, the Commission can defer confidently to those decisions. Under such circumstances, the Commission can be assured that ISO proposals to changes market rules and procedures would promote competitive markets and are not designed to favor any one group of market participants.

PJM argues further that the Commission accord greater flexibility to properly structured RTOs to change market rules and procedures without Commission filings. An RTO with an established stakeholder process could publish some changes in market rules on its internet site, without requiring prior Commission approval. In the event that a market participant objected, it could file a complaint with the Commission. PJM says the benefit is that the market would not be hindered by delay in implementing new rules. Other rules could be permitted to go into effect upon filing, rather than at the end of the Commission review process.

Some commenters suggest that the Commission be particularly deferential to decisions that result from ADR processes. For example, PNGC supports strong and broad dispute resolution power in an RTO. It argues that many small transmission users currently have no effective way to be heard regarding service complaints, outage restoration, and adequacy of equipment or maintenance because of the high cost of bringing such a dispute to the Commission. In addition, Desert STAR

[108] *See, e.g.,* American Forest, TDU Systems, WPPI, Sonat, Illinois Commission, Arizona Commission, FMPA, Tampa Electric, Advisory Committee ISO–NE. Comments are addressed in more detail later in the discussion of existing discriminatory conduct.

[109] *See, e.g.,* United Illuminating, Southern Company, MidAmerican, Duke, PSE&G, FP&L, Entergy, FirstEnergy, Alliance Companies, Lenard, Florida Power Corp.

asserts that where the Commission has approved the charter governance and ADR processes of an RTO as being sufficiently broad-based and independent, the Commission should give some deference to decisions reached through the RTO's ADR processes. However, deference in dispute resolution to an RTO should not impair a transmission user's fundamental rights under section 211 of the FPA. Because the RTO will be a jurisdictional entity, the Commission is an appropriate appeals forum. Similarly, Seattle supports the Commission proposal to defer to RTOs on matters involving commercial, operating and planning practices, as well as to resolve disputes, but argues that it is too early to tell whether ISOs transcos or other forms of RTOs can be deferred to in lieu of regulatory filings.

MidAmerican welcomes the Commission's proposed lighter-handed approach to regulation, but questions whether lighter-handed regulation, in fact, will be derived from the proposed rule. MidAmerican proposes that the Commission issue a policy statement to provide general guidance on how it intends to give deference to RTOs. For example, the policy should outline that, if a transmission owner follows RTO directives, it will be presumed that the transmission owner does not have transmission market power and that it is not capable of transmission market discrimination. The Commission should give deference to RTOs to design tariffs that include rate incentives and should permit returns on equity that compensate transmission owners for additional risks and for competitive market development.

A number of commenters argue that there is as yet no evidence to support the conclusion that RTO formation should lead to lighter-handed regulation. Duke and Entergy argue that each of the existing ISOs has been mired in significant litigation with market participants, and the Commission's dockets are loaded with cases arising out of decisions made by ISOs. They and NECPUC suggest that this raises the possibility that RTOs represent a new layer of regulatory oversight of market activities, supplementing rather than replacing federal and state regulation. FP&L states that the independence and objectivity of the Florida Public Service Commission make it unnecessary to create a formal (and costly) separate entity to operate and oversee the Florida grid as an RTO.

Other commenters suggest that the probability that RTOs can be self-regulating may be overstated. APPA argues that existing ISOs still represent the interests of the transmission owners that formed these ISOs. In addition, it argues that each ISO is a market participant because its revenue recovery is affected by the performance of transmission, ancillary services, and energy imbalance spot markets. It suggests that the right to self-regulation must be earned in the marketplace, not bestowed by regulators in advance.

NECPUC argues that not only must an RTO be properly structured to be self-regulating, so must the utilities involved, or the RTO will constantly be involved in the business of dispute resolution. It suggests that during a transition phase, a certain level of active regulation may be inescapable. For example, it notes that the Commission stepped in quite definitively in developing the governance of the New England Power Pool. NECPUC believes that strong intervention by the Commission was effective at achieving progress when the parties in New England stalemated.

PG&E claims that an RTO is uniquely situated to handle a number of responsibilities, including reliability enforcement and sanctions, market monitoring, and reporting non-reliability market-related violations. However, a single entity, no matter how well-structured and independent, cannot successfully fulfill several competing roles simultaneously, *i.e.,* serve as judge, jury and advocate. While the RTO can do much to create region-specific processes that meet the needs of market participants, the Commission must retain ultimate oversight. The RTO is not a substitute for this function. With the tremendous volume of transactions flowing through an RTO, even small errors in energy or financial accounting can lead to huge cost shifts. Market participants need to have a remedy at the Commission if issues are not resolved adequately by the RTO.

Other commenters believe that the Commission may have to play a strong role in ADR. Arizona Commission urges the Commission to give respect rather than deference to decisions reached through an RTO's ADR processes. TDU Systems state that the ability of an RTO transmission customer to obtain ultimate Commission review of a dispute with the RTO (or another RTO customer) should not be cut off. RTO tariffs should contain ADR provisions that allow for mediation or other low-cost forms of ADR so disputes can, if possible, be resolved without resort to the Commission. If this is not possible, the Commission should consider any dispute that comes to it after the conclusion of ADR at an RTO on a *de novo* basis.

In dealing with disputes between RTOs and their customers, TDU Systems suggests that the Commission be sensitive to the issue of ''minority rights.'' The Commission should ensure that transmission customers with complaints against their RTOs get due process and a full and fair opportunity to air their concerns. Just because a customer may take a position in a dispute not shared by many others does not mean that it is automatically wrong.

Moreover, TDU Systems believe that the Commission, in considering the ADR issue, should make a distinction between ISOs or other RTOs that are not-for-profit or quasi-governmental in nature and for-profit RTOs. For-profit RTOs may not necessarily be well suited to be the arbiters of disputes, especially where they are an involved party. It would be inappropriate for the Commission simply to ''off load'' dispute resolution duties to a private for-profit entity, especially if the entity is an interested party in the dispute. ISOs, on the other hand, are more quasi-governmental in nature, and if fully independent, may be in a better position to attempt to resolve a dispute, subject to Commission review.

Duke asserts that streamlined filings and approval procedures could reduce costs that would otherwise be borne by market participants. Reducing regulatory burdens could constitute one form of incentive to encourage RTO participation. The policy could be applied equally for non-profit and for-profit RTOs. On the other hand, TDU Systems argues that opportunities for streamlined RTO filings could set a very dangerous precedent, especially if applied to incentive rate filings of for-profit RTOs. RTOs will still be monopolies (although hopefully large horizontal ones, rather than smaller, vertically integrated ones). The norm for RTO filings should still be full Commission scrutiny. Entergy argues that the Commission should encourage proposals submitted by RTOs designed to increase regulatory efficiencies and reduce regulatory burdens imposed on RTOs. The Commission should specifically declare its willingness to entertain proposals to streamline filing requirements. The Commission could encourage innovative ways to reduce regulatory costs by authorizing performance-based rates that reward RTOs for reducing regulatory costs.

Commission Conclusion. We conclude that properly structured RTOs throughout the United States can provide significant benefits in the operation of the transmission grid. The comments received reinforce our preliminary determination in the NOPR that RTOs can effectively remove existing impediments to competition in the power markets.

Description of Benefits. We conclude that RTOs will provide the benefits that we described in detail in the NOPR, and others that commenters mention.[110] While we acknowledge that the level of RTO benefits may vary from region to region depending on the current transparency and efficiency of markets, the Commission believes that benefits from RTO's would be universal. These benefits will include: increased efficiency through regional transmission pricing and the elimination of rate pancaking; improved congestion management; more accurate estimates of ATC; more effective management of parallel path flows; more efficient planning for transmission and generation investments; increased coordination among state regulatory agencies; reduced transaction costs; facilitation of the success of state retail access programs; facilitation of the development of environmentally preferred generation in states with retail access programs; improved grid reliability; and fewer opportunities for discriminatory transmission practices.[111] All of these improvements to the efficiencies in the transmission grid will help improve power market performance, which will ultimately result in lower prices to the Nation's electricity consumers.

As stated in the NOPR, we expect that RTOs can reduce opportunities for unduly discriminatory conduct by cleanly separating the control of transmission from power market participants. An RTO would have no financial interests in any power market participant, and no power market participant would be able to control an RTO. This separation will eliminate the economic incentive and ability for the transmission provider to act in a way that favors or disfavors any market participant in the provision of transmission services.

Most commenters support the premise that RTOs can be beneficial in addressing the remaining transmission-related impediments to full competition in the electricity markets. Although we recognize certain differences in perspective about the existence of, or potential for, widespread discrimination by current transmission owners, no one seriously disputes the benefits of a marketplace where service quality and availability are uniform, where users of the network are treated equally, and where commercially important data are readily available to all. Although some commenters support the NOPR proposal only if the costs of establishing RTOs do not exceed the benefits, a subject discussed further below, most believe that the benefits listed in the NOPR are accurate and can be achieved through an RTO.

We recognize that some commenters believe that either RTOs alone will not solve all of the identified problems, or individual benefits can be achieved in ways other than creating RTOs. Both of these observations may have some merit. However, we believe that the creation of RTOs is one action that can address all of the identified impediments to competition and provide all or most of the identified benefits.

We also recognize that there are those who worry that the costs of establishing an RTO will outweigh the benefits. We believe this concern fails to account for the flexibility we have built into this rule. While many look at the high costs involved with respect to establishing some existing ISOs and PXs, this rule does not require an RTO to follow any specific approach. For example, this rule does not require the consolidation of control areas nor does it require the establishment of a PX. We are allowing significant flexibility with respect to how and, in some cases, when the minimum characteristics and functions are satisfied. Accordingly, we do not believe it will be necessary to expend the same level of resources that were expended, *e.g.,* in California, to create an RTO satisfying our minimum characteristics and functions. We therefore conclude that the flexibility built into the Final Rule will allow RTOs to create streamlined organizational structures that are not overly costly. Moreover, with five ISOs now operating in the United States, there is considerable experience available regarding what works and what does not with respect to regional transmission entities. This experience should make it somewhat easier, and more cost efficient, to create new RTOs.

As we stated in the NOPR, by improving efficiencies in the management of the grid, improving grid reliability, and removing any remaining opportunities for discriminatory transmission practices, the widespread development of RTOs will improve the performance of electricity markets in several ways and consequently lower prices to the Nation's electricity consumers. To the extent that RTOs foster fully competitive wholesale markets, the incentives to operate generating plants efficiently are bolstered. The evidence is clear that market incentives can lead to highly efficient plant operations. The incentives for more efficient plant operation can also affect existing generation facilities. Especially noteworthy is the recent experience that indicates improvements in the generation sector in regions with ISOs. Regions that have ISOs in place are undergoing dramatic shifts in the ownership of generating facilities. Large-scale divestiture and high levels of new entry in California and the Northeast are changing the ownership structure of these regions' generators. Access to customers and the presence of competing suppliers are creating the incentives for better-performing plants.

By improving competition, RTOs also will reduce the potential for market power abuse. As discussed earlier, eliminating pancaked transmission prices will expand the scope of markets and bring more players into the markets. By eliminating the mistrust in the current grid management, entry by new generation into the market will become more likely as new entrants will perceive the market as more fair and attractive for investment. And with more players, the market becomes deeper and more fluid, allowing for more sophisticated forms of transacting and better matching of buyers and sellers.

Estimation of Benefits. The full value of the benefits of RTOs to improve market performance cannot be known with precision before their development, and we do not yet have a sufficiently long track record with existing institutions with which to measure. The Commission staff has estimated a subset of the potential cost savings from RTOs as part of its National Environmental Policy Act analysis. In the Environmental Assessment (EA) for this rulemaking, three scenarios were developed to estimate potential economic and environmental effects of the rulemaking.[112] The scenario analysis was conducted using a computer simulation model of the continental U.S. electric power system over the

[110] The benefits described in this section are not intended to include all benefits that RTOs could provide. Some of the principal benefits of RTOs (*e.g.,* more effective management of parallel path flows, improved congestion management) are addressed in later discussions of RTO minimum characteristics and functions.

[111] FERC Stats. & Regs. ¶ 32,541 at 33,716–20.

[112] One of these scenarios assessed transmission effects only, the second assessed generation efficiencies in addition to transmission effects, and the third posited increased entry of new supply and demand choices.

period 1997 to 2015.[113] The Commission adopts staff's analysis.

The results of the EA modeling present a range of potential cost savings resulting from the changes in modeling assumptions in each scenario. Although this Final Rule does not mandate RTO formation, full development of RTOs as envisioned by the Commission in this rule could offer substantial economic benefits. The EA scenarios modeled resulted in average annual savings of up to $5.1 billion per year over the 2000–2015 period. Based upon review of the EA scenarios and comparison with other existing analyses of competitive electric power markets, the best estimate from the EA analysis of annual benefits that could result from RTO formation is $2.4 billion per year. This estimate results from a scenario in which the modeling assumptions for transmission and generation efficiency are selected for consistency with other economic analyses of competitive power markets, including the Order No. 888 Environmental Impact Statement analysis conducted by Commission staff in 1996.[114]

These estimates do not represent a complete economic analysis of the rulemaking because the EA analysis addressed only factors that may change the dispatch of power plants or future generating capacity decisions. The model accounts for production costs (capital additions, operations and maintenance expenses, and fuel) equal to roughly one-third of the annual sales revenue now passing through the industry, and does not include such cost categories as existing (sunk) capital, the distribution system, and end user charges such as taxes. If other cost savings were realized, for example, from merger-like consolidation savings in the transmission grid, these savings would be additional to those estimated in the EA. Benefits from elimination of market power and improved intra-regional congestion management are also not included in the calculation and could represent significant additional savings.

The costs of RTO formation are not explicitly captured in the EA analysis, nor are any potential costs associated with the provision of incentives for RTO formation or operation. Costs of RTO formation cannot be well estimated because of the wide range of design choices that the rule allows for a new RTO. For instance, the choice of building a dedicated telecommunications and data infrastructure, as opposed to relying on existing infrastructures, can have a large effect on the initial cost of an RTO.[115]

Based on review of cost studies for existing ISOs, it appears unlikely that the costs of RTO formation will exceed RTO cost savings on an annualized basis over time. This is because most of the costs are capital investments that occur at the beginning of the RTO's operation. But whether the costs in the initial period are under $10 million or up to several hundred million dollars (and more likely between these two figures) for an RTO, they are small in comparison with the ongoing annual savings that RTOs may provide.

As discussed above, our best estimate of cost savings from RTO formation is $2.4 billion annually, with potential cost savings estimated to be as high as $5.1 billion annually. This represents about 1.1 to 2.4 percent of the current total costs of the U.S. electric power industry.[116] Such savings can be considered in the context of recent analysis of the economic benefits of further industry restructuring.[117] The wholesale cost savings the Commission is anticipating from the formation of RTOs are properly viewed as distinct from the larger savings that may result from competitive retail power markets. However, RTOs can also help achieve retail access and its associated benefits by creating a robust wholesale power market. In this sense the cost savings from retail access depend on the Commission fulfilling its RTO objectives.[118]

Light-Handed Regulation. One of the benefits of RTOs that we identified in the NOPR was that the existence of a properly structured RTO would reduce the need for Commission oversight and scrutiny, which would benefit both the Commission and the industry. We stated that to the extent an RTO is independent of power marketing interests, there would be no need for the Commission to monitor and attempt to enforce compliance with the standards of conduct designed to unbundle a utility's transmission and generation functions. We also stated that an independent RTO with an impartial dispute resolution mechanism could resolve disputes without resort to the Commission complaint process, and that it is generally more efficient for these organizations to resolve many disputes internally rather than bringing every dispute to the Commission. Further, we noted that the Commission has in the past indicated its willingness to grant more latitude to transmission pricing proposals from appropriately constituted regional groups [119] and, to the extent that RTOs increase market size and decrease market concentration, the competitive consequences of proposed mergers would become less problematic and thereby help further streamline the Commission's merger decision-making process.

We continue to believe that the types of reduced regulatory scrutiny mentioned in the NOPR, and summarized above, are possible and appropriate for RTOs. A number of commenters, however, have expressed concern that it is premature to reduce regulation of RTOs, and that RTOs will be monopolies that will require continued regulation. We believe that this concern stems from a misunderstanding of our concept of light-handed regulation. Admittedly, this concept is subject to varying interpretations.

We clarify that we will continue to apply the level of regulation and scrutiny that is necessary to ensure that public utilities comply with the FPA and our regulations. Only when we determine that a different form of regulation will adequately protect the public interest, we will allow a reduced oversight role for the Commission.

Furthermore, our encouragement of the use of ADR by participants in RTOs to resolve disputes without resort to formal complaint proceedings is not new. In our RTG Policy Statement, we encouraged RTGs to develop alternative dispute resolution procedures for resolving transmission issues, particularly technical and reliability issues. We also stated that we would be willing to entertain proposals for some degree of deference to decisions rendered pursuant to an ADR process, pursuant to procedures that are specified in an agreement and assure

[113] The Integrated Planning Model (IPM) was developed for the U.S. Environmental Protection Agency by ICF Inc. *See* 3.3.1 of the Commission Staff's Environmental Assessment in this proceeding.

[114] Order No. 888, *Final Environmental Impact Statement*, FERC/EIS–0096, FERC Stats. & Regs. ¶ 31,036 at 31,860–96.

[115] *See, e.g.*, California ISO, *Cost Performance Benchmarking Study of Independent System Operators*, revised version of Feb. 17, 1999.

[116] Defined as revenue from sales to ultimate users, which were reported as $215 billion in 1997. *See* Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA–0384(97) (July 1998).

[117] *See, e.g.*, Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE–PO–0059 (May 1999).

[118] DOE's Economic Analysis of the Comprehensive Electricity Competition Act shows an estimated cost savings from a national policy of retail access to be $20 to $32 billion per year. *See id.*

[119] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55031 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005, at 31,140, 31,145, 31,148 (1994) (Transmission Pricing Policy Statement).

due process for all participants. [120] We stated there, and we reaffirm here, that while the Commission cannot delegate its authority, it can give deference to resolutions that meet the standards of the FPA.

We reiterated this concept in the eleven ISO principles we set forth in Order No. 888. We stated there that an ISO should provide for a voluntary dispute resolution process that allows parties to resolve technical, financial, and other issues without resort to filing complaints at the Commission.[121] We have also expressed our willingness to grant some deference to changes to an open access tariff by an ISO concerning a regional solution to an identified regional problem based on what we understand is a broad consensus.[122]

Accordingly, we believe that some degree of deference can be granted on certain issues to independent RTOs that have appropriate procedural mechanisms in place to ensure fair representation of viewpoints. We cannot delineate here precisely the degree of deference that is appropriate, or on what issues. To the extent some issues can be fairly resolved within a region without formal Commission procedures, a benefit accrues to both the parties and the Commission.

In addition, we note that some of the innovative ratemaking policies discussed later in this Final Rule are consistent with light-handed regulation, since we expect that these policies may result in reduced levels of regulatory scrutiny. We emphasize, however, that we will not delegate or fail to exercise our regulatory responsibilities. We also recognize that the degree of deference and reduced regulatory scrutiny accorded to an RTO may necessarily depend on the ability of the RTO to reach consensus solutions to regional issues.

C. Commission's Approach to RTO Formation

The NOPR proposed an approach to RTO formation that embraces several general principles: first, as a matter of policy, we should strongly encourage transmission owners to participate voluntarily in RTOs; second, we should be neutral as to organizational form (*e.g.*, ISO or transco) of an RTO as long as it satisfies our minimum characteristics and functions; and third, we should provide maximum flexibility as to the specifics of how an RTO can satisfy the minimum characteristics and functions. We sought comment on these principles and specifically asked whether we should generically mandate RTO participation [123] or whether market-based rates or merger approvals should be conditioned on RTO participation.[124]

Based on the wide array of comments received, which we discuss next, and the voluminous record compiled in this rulemaking proceeding, we conclude that a voluntary approach to RTO formation represents a measured and appropriate response to the technical impediments to competition that have been identified as well as the lingering discrimination concerns that have been raised. We believe that voluntary formation of RTOs will address the fundamental economic and engineering issues which confront the industry and the Commission, and will help eliminate any actual or perceived discriminatory conduct by entities that continue to control both generation and transmission facilities.[125] Further, we believe that the voluntary process adopted in this rule, in conjunction with the innovative transmission pricing reforms that we will permit RTOs to seek, will be successful in achieving widespread formation of RTOs in a timely manner. Our adoption of a voluntary approach to RTO formation in this Final Rule does not in any way preclude the exercise of any of our authorities under the FPA to order remedies to address undue discrimination or the exercise of market power, including the remedy of requiring participation in an RTO, where supported by the record.

1. Voluntary Approach

Comments. Comments as to whether the Commission should require formation of and/or participation in RTOs break down into five main categories: (1) The Commission should require formation of and participation in RTOs; (2) formation of and participation in RTOs should be voluntary; (3) the Commission should encourage voluntary RTOs, but with strong enforcement mechanisms; (4) RTOs should be voluntary, but if they do not form or if utilities do not participate, the Commission should mandate them; and (5) RTOs should be voluntary, but the requirements of the NOPR effectively create a mandate.

Most investor-owned utilities argue that RTOs should be voluntary. Most municipal utilities, customer groups, consumer advocates, and marketers argue that the Commission should require RTOs. State commissions and cooperatives are more evenly split. These characterizations, however, are broad generalizations, and there are strong exceptions to each statement.

Comments That the Commission Should Require Formation of and Participation in RTOs. The most extensive argument for mandating RTOs comes from TAPS and is representative of the positions of a number of public power utilities and other transmission customers. [126] TAPS argues that the non-mandatory approach leaves the keys to reform in the hands of the wrong people—the monopolists who have market power—and that the voluntary creation of RTOs will give opportunities for monopolists to maintain their market power. TAPS presents extensive arguments as to the Commission's authority to mandate and its obligation under the FPA to do so. They state:

> Only by mandating that jurisdictional utilities participate in * * * RTOs will the Commission protect against * * * utilities' inclinations to form alternative RTOs that are structured to perpetuate or enhance their competitive position. Compelling such participation is also the only way for the Commission to satisfy its statutory obligations to eradicate undue discrimination and protect against unjust and unreasonable pricing of both transmission service and wholesale generation sales.

TAPS further argues that past attempts to allow voluntary formation of RTOs have not been successful. Only where states have required ISOs or where the Commission has required them as part of a merger proceeding have effective ISOs been formed.

TDU Systems also presents extensive arguments for a mandate. It argues that the need for a national system of RTOs is urgent; that the Commission cannot rely purely on voluntary actions of transmission owners; that only a mandate will create RTOs in a timely fashion; and that inducements are counterproductive. WPPI states that the financial incentive to protect a transmission owner's generation investment is much stronger than any transmission incentive FERC can give to induce RTO participation. First Rochdale argues that voluntary RTOs will create too great an emphasis on forcing parties to litigation and other

[120] Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (Aug. 5, 1993), FERC Stats. & Regs. ¶ 30,976 (1993) (RTG Policy Statement).

[121] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,732.

[122] *See* PJM Interconnection, L.L.C., 84 FERC ¶ 61,212 (1998).

[123] FERC Stats. & Regs. ¶ 32,541 at 33,762.

[124] *Id.*

[125] These engineering, economic and discrimination issues are discussed in Section III.A above.

[126] *E.g.*, APPA, Empire District, FMPA, Great River, Lincoln, UAMPS, UMPA.

costly, time consuming dispute resolution.

Some investor-owned utilities support a mandate.[127] For example, Cinergy presents arguments similar to those of TAPS, and believes that ''all jurisdictional utilities must be required to transfer control of their transmission facilities to a qualified ISO, which shall integrate those facilities into an RTO approved by the Commission.''

A number of marketers believe that RTOs must be mandated. Sonat is not convinced that incentives alone are sufficient to persuade transmission providers to follow through with RTO formation. NEMA believes that participation by all transmission owners should be mandatory, but that the form of the RTO should be allowed to evolve.

Many industrial customers agree that RTOs must be required. PJM/NEPOOL Customers argue that the goals of the Commission cannot be achieved without mandatory participation by all transmission owners in RTOs. They go further to state that experience from both the Midwest ISO/Alliance debate over formation of ISOs and from the natural gas industry demonstrates monopolists will not act effectively to eliminate discrimination without strong mandates attached to strong penalties.

Residential consumer advocates and environmental organizations concur. Public Citizen says that the Commission should order the creation of three non-profit public transmission companies (one each for the Eastern, Western, and ERCOT interconnections) and order each public transco to purchase all of the transmission facilities needed to provide customers with transmission service.

Project Groups recommends that the final rule be strengthened to require that if owners do not voluntarily transfer control of facilities to an approved RTO by a date certain, the Commission will either order the transfer (in the case of jurisdictional utilities) or take other actions designed to minimize the opportunities for resisting owners to use their facilities in anti-competitive ways.

A number of state commissions support a mandatory RTO regime imposed by the Commission. Illinois Commission does not believe that the voluntary approach set out in the NOPR is likely to obtain its objectives and especially not in a timely manner, noting that voluntary efforts ''for more than six years'' have failed and that the encouragements and incentives contained in the NOPR are unlikely to change the situation. Indiana Commission points to its experience with the Midwest ISO/Alliance debates as indicating that the Commission must take a more assertive role. Montana Commission agrees, pointing to unwillingness of transmission owners to give up control and to concerns about cost-shifting. It recommends that the Commission strengthen the NOPR to ensure the prompt formation of RTOs using all the tools at its disposal. Pennsylvania Commission argues that in order to be stable, both as to their authority and with respect to membership participation, RTOs must be mandatory. Virginia Commission argues that the goal of independence is in conflict with a voluntary approach.

Wisconsin Commission argues that the Commission should move forward quickly and require all transmission facilities to be placed under the control of an RTO. In the absence of any action from FERC to require utility membership, it states, it is unclear how any effort to resolve the ''Swiss cheese'' problems already experienced in the Midwest can succeed. Ohio Commission argues that it continues to believe that the mandatory participation and boundary drawing approach is more appropriate.

Comments That Formation of and Participation in RTOs Should Be Voluntary. The most extensive presentation of the argument that RTOs should and must be voluntary comes from Indianapolis P&L and FP&L, which make mostly legal arguments that are addressed below. Southern Company argues that a voluntary, flexible RTO policy is consistent with desires of the states as reflected in statements given at the consultations with the states held by the Commission. It also avers that an RTO is not required to achieve the goals of the NOPR. Alliance Companies and Trans-Elect argue that voluntary formation is the key to RTO success, noting that the Commission's voluntary approach of encouraging regionalization of the transmission grid has been successful and there is no reason to doubt its continued success.

EEI suggests that the voluntary approach is working well, indicating that five ISOs have been approved serving 46 percent of U.S. customers and 38 percent of total MWh sales. They state that four other regions have proposed or are about to propose RTOs which will result, within three years since the issuance of Order No. 888, in nearly 63 percent of the nation's electricity customers being served by regional transmission entities. They go on to argue that a mandate could stimulate litigation that would slow this voluntary development.[128]

A number of public power entities, including municipal utilities, cooperative utilities, Federal Power Marketing Administrations, and others, also support a voluntary approach. TVA argues that FERC's proposal to make RTO participation voluntary is a wise one, that as RTOs demonstrate their effectiveness and the benefits of RTOs become more evident, transmission owners likely will be persuaded to participate and the holes in the RTOs should disappear. CMUA argues that mandatory RTOs are not likely to be formed through collaborative processes and therefore are not likely to take into account broad stakeholder input. Tacoma Power supports voluntary formation because some utilities may not find that the cost savings are sufficient to warrant the expenditure necessary. Also, it states that public power utilities may face legal obligations or restrictions that inhibit their participation and that such utilities should not face penalties or sanctions for not participating.[129]

A number of state commissions support voluntary formation of RTOs. Alabama Commission argues that the Commission does not have authority to mandate RTOs. Florida Commission agrees and states that any action by the Commission must be on a case-by-case basis, and the Commission should defer to states in developing regional approaches. Michigan Commission believes that there is a solution short of mandating RTO formation, but that uses FERC's unique national perspective and authority to facilitate larger RTO formation. Wyoming Commission urges the Commission not to codify or mandate anything other than the general framework for RTOs and thereby allow the voluntary process an opportunity to work.[130]

Comments That the Commission Should Encourage Voluntary RTOs But With Strong Enforcement Mechanisms. The Justice Department argues that the

[127] *E.g.*, Minnesota Power, WEPCO, PG&E, PECO.

[128] Other transmission-owning utilities supporting voluntary development and opposing mandates are Detroit Edison, Duke, Entergy, Florida Power Corp., SCE&G, Metropolitan, MidAmerican, NEPCO *et al.*, NU, NSP, Montana-Dakota, Tampa Electric, TXU Electric, United Illuminating, CP&L, Central Maine and Virginia Power.

[129] Other public power and cooperative entities supporting voluntary formation of RTOs include Big Rivers, East Kentucky, Georgia Transmission, South Carolina Authority, SMUD, Seattle, JEA, LPPC, NRECA, Los Angeles, MEAG, Oglethorpe, Platte River, NPRB, NPPD, RUS and Tri-State.

[130] Other state commissions supporting voluntary formation include South Carolina, Iowa, New York, and Washington. Other entities supporting voluntary formation of RTOs include NYPP, SRP and Cal ISO.

NOPR makes a strong case for mandating RTOs. It recommends that a regime of ''carrots and sticks'' be carefully designed to reasonably guarantee complete voluntary compliance, rather than merely promote greater voluntary compliance.

Enron/APX/Coral Power argue that the Commission should take steps to induce transmission owners to participate in RTOs.[131] They doubt, however, that performance-based ratemaking alone will be a sufficient inducement and recommend Commission procedures to prevent transmission owners that fail to participate in RTOs from misusing their transmission systems to favor their own or affiliated uses of their systems. These could include regional proceedings to impose added safeguards against violations, presumptions of ineligibility for market-based rates, and presumptions that mergers are inconsistent with public interest absent membership in an RTO.

Comments That RTOs Should Be Voluntary, But if They Do Not Form, the Commission Should Mandate Them. PNGC argues that if a voluntary RTO encompassing the Pacific Northwest does not come about in a reasonably short time, the Commission should explore its authority or seek new authority to mandate participation in RTOs. Fertilizer Institute believes that the Commission has sufficient authority to mandate RTOs but would likely be bogged down in endless litigation should it do so, and so recommends that the Commission pursue a voluntary approach, but, should that not work, proceed with a requirement. WPSC argues that encouraging voluntary participation in RTOs is the appropriate starting place. However, the Commission must be prepared to take more direct action, including increased legislative authority, to ensure the participation of utilities that do not voluntarily choose to join an RTO.

Comments That RTOs Should Be Voluntary, But the Requirements of the NOPR Effectively Create a Mandate. Puget states that if the Final Rule continues to reflect a position that nonparticipation in the RTO will result in negative regulatory consequences for the nonparticipant, then the RTO proposal cannot really be said to be voluntary. CP&L argues that mandatory filings, coupled with threats of withholding benefits and/or leveling penalties for those that do not choose to ''voluntarily'' join and RTO, do not present a picture of a truly voluntary process.

Comments on Sanctions for Non-Participation. Most vertically integrated public utilities oppose conditioning market-based rates and merger approval on RTO participation, while most transmission customers favor the Commission using conditioning authority. A number of utilities express concern that the Commission may be exceeding its legal authority, and that conditioning would undermine the voluntary nature of the RTO initiative. Florida Power Corp. argues that the Commission cannot impose penalties for failure to participate voluntarily in an RTO in contravention of the FPA. Puget contends that the possibility of penalties for non-participation means that no provision is made for participation to be truly voluntary. Duke expresses concern that potential revocation of market-based rate authorization and refusal to find a merger in the public interest are actions that make it legally or economically impossible for any public utility not to participate in an RTO. EEI observes that such linkage would change settled law requiring reasoned analysis or factual findings. Similarly, Consumers Energy submits that summary withdrawal of existing market-based rate authorization must be justified by substantial evidence of changed circumstances. CP&L claims that the Commission cannot impose RTO participation conditions on a proposed merger that go beyond the consistency with the public interest standard under the FPA.

Two commenters suggest that the Commission must proceed on a case-by-case basis. MidAmerican contends that there is no clear indication that the number of parties competing in generation markets is so small to cause inadequate levels of competition. Since changes to restructure the industry into RTOs will be costly and difficult for all parties, mandates or sanctions should be based only on willful violations of Commission policy. LG&E concurs that only where the record supports a case-specific finding that a transmission owner's failure to participate in an RTO will result in undue discrimination or the ability to exercise market power should the Commission take remedial steps to address the situation so that the Commission is on firm legal grounds.

On the other hand, a number of commenters believe the Commission must require RTO participation as a condition of future market-based rate transactions and authorizations. TAPS notes that this is necessary for the Commission to meet its obligation to protect consumers from unjust and unreasonable rates if it intends to pursue a lighter-handed regulatory approach, adding that only RTOs of appropriate size and structure will be able to meet fully the Commission's statutory obligation to protect consumers. Oneok and New Smyrna Beach argue that manipulation and undetectable anticompetitive conduct for which there is no practical after-the-fact remedy are concerns that could be alleviated by an RTO and that, accordingly, denial of merger approval or market-based rate authorization is well within the Commission's authority when anticompetitive factors have not been mitigated.

PJM/NEPOOL Customers, Great River, East Texas Cooperatives and PNGC support revoking market-based rate authorization to remedy inherent discrimination resulting from non-participation and also using non-participation as a factor in merger analysis. APPA favors imposing the merger condition in the form of an immediate requirement to participate given the Commission's prior experience with conditioning mergers with commitments to join an ISO. merican Forest supports conditioning all future market-based rate transactions on participation. H.Q. Energy Services encourages the Commission to explore the full extent of its authority under the FPA to compel participation in RTOs.

Enron/APX/Coral Power recommend that the Commission create a rebuttable presumption that RTO participation is required for approval of market-based pricing or a transfer of facilities under section 203 of the FPA. For market-based rate authorizations, the Commission should establish a presumption that a decision by a transmission owner not to participate in an RTO is evidence that it is misusing its transmission facilities to advantage its merchant function. This presumption could be rebutted through a demonstration that stand-alone operation of the non-participant's grid serves the public interest as well as or better than participating in an RTO. They suggest that utilities currently with market-based rate authorizations should be ordered to show cause by the December 15, 2001, implementation deadline why their market rate authorizations should not be revoked. Enron/APX/Coral Power also recommend that all sales, leases, mergers and consolidations of transmission systems be conditioned on RTO participation based on a presumption that it is inconsistent with the public interest to dispose of transmission facilities without eliminating the incentive to

[131] Concurring are H.Q. Energy Services, Midwest Energy and Oregon Office.

discriminate by committing the operation of those facilities to an RTO.

Industrial Consumers believes that the engineering and economic efficiencies of RTO participation loom so large that the Commission is justified in adopting a presumption that a decision by a transmission owner not to participate in an RTO is evidence that it is misusing its transmission facilities. Industrial Consumers recommends that the Commission assert jurisdiction over the transmission component of bundled sales, and order that the rates, terms and conditions offered under the OATT apply to all eligible customers. This would deprive vertically-integrated utilities of the incentive to resist RTO participation.

State commission commenters tend to favor the Commission using conditioning authority, but some are not sure this will necessarily encourage participation in RTOs. Oregon Commission comments that unless a utility can demonstrate that it cannot manipulate the transmission system to its advantage or that an RTO is impossible, the Commission should revoke its ability to sell at market-based rates. Complaints of unfair practices without credible reasons should be prima facie evidence of market power. Pennsylvania Commission recommends that the Commission revisit previously granted market-based rate authorizations. Indiana Commission cautions, however, that a recalcitrant utility that does not join an RTO may not perceive loss of market-based pricing authorization as detrimental. Illinois Commission does not oppose conditioning merger and market-based rate approvals on RTO participation, but it also believes that the threat of these penalties may be inadequate to induce RTO participation.

Comments on Consequences for Failure to File, or Filing Alternative Explanation. The majority of comments on this issue support the Commission taking additional action if adequate RTOs do not form. PJM/NEPOOL Customers suggests that strict penalties must be assessed against actions inconsistent with RTO formation. Oneok suggests that certain benefits that are within the Commission's authority and discretion to grant or deny should be withheld from utilities unwilling to participate. Project Groups recommend that the Final Rule provide that the Commission itself create RTOs if the stakeholders are unable or unwilling voluntarily to do so by a reasonable date certain. PNGC suggests that if RTOs do not form within a reasonable time, the Commission should explore its authority or seek new authority to mandate participation by all utilities.

On the other hand, Duke is concerned that the Commission may not accept valid reasons for nonparticipation and use the October 15, 2000, alternative filings as vehicles to mandate RTO membership. Duke offers that the Commission cannot consider imposing penalties for non-participation while simultaneously claiming that its policy on participation is voluntary. Seattle cautions that the Commission should exercise care not to unfairly sanction transmission-owning utilities that cannot participate in an RTO (*e.g.,* where good cause is shown that participation would violate state and local legal obligation, or the costs of RTO participation outweighs the benefits).

Commission Conclusion. Based on the record before us with respect to undue discrimination and market power, as well as with respect to economic and engineering issues affecting reliability, operational efficiency, and competition in the electric industry, it is clear that RTOs are needed to resolve impediments to fully competitive markets. However, we continue to believe, as we proposed in the NOPR, that at this time we should pursue a voluntary approach to participation in RTOs.

We acknowledge that there are many commenters who are skeptical that a voluntary approach will be able to accomplish our stated objective, which, as we stated in the NOPR,[132] is for all transmission-owning entities to place their transmission facilities under the control of RTOs in a timely manner. In general, they argue that those with a market advantage will not easily give it up, and that voluntary efforts to date have not been very successful in creating effective regional entities.

However, we believe that a voluntary approach as we have structured it, with guidance and encouragement from the Commission, is most appropriate at this time. Given the rapidly evolving state of the electric industry, we want to allow involved participants the flexibility to develop mutually agreeable regional arrangements with respect to RTO formation and coordination. Further, we want the industry to focus its efforts on the potential benefits of RTO formation and how best to achieve them, rather than on a non-productive challenge to our legal authority to mandate RTO participation.

We believe the voluntary approach to RTO formation can be more successful now than in the past for several reasons. The pace of industry restructuring is accelerating. Many formerly vertically integrated utilities have recently recognized the strategic benefits to them of concentrating solely in one of the traditional utility areas (generation, transmission, or distribution). Moreover, the NOPR has focused industry attention on RTOs and their benefits. Further, this Final Rule is providing clear rules and guidance on what is necessary to form an RTO. Through this Final Rule, we are also committing the Commission to act as a catalyst in RTO discussions by initiating and encouraging a collaborative process. Finally, we have provided in this Final Rule for certain favorable ratemaking treatments for those who assume the risks of the transition to a new structure, which should, at a minimum, eliminate any rate disincentives to RTO formation.

We are not adopting as a generic policy in this Final Rule either that RTO participation is required in order to retain or obtain market-based rate authorization for wholesale power sales, or that RTO participation is required for a disposition of jurisdictional facilities to be in the public interest. However, in response to those who argue that the Commission has a statutory responsibility to remedy undue discrimination and anticompetitive effects when evaluating market-based rate and merger requests, we recognize that we may have to consider, in individual cases, issues that arise as to whether market power has been mitigated in the absence of RTO participation or as to whether a merger would be in the public interest without RTO participation.

While we have concluded on this record that it is in the public interest to provide for a voluntary approach to RTO formation that relies upon encouragement, guidance, and support from the Commission, this does not mean that all aspects of this Rule are voluntary. The filing requirements set forth in section 35.34(c) of the new regulations are mandatory. In other words, public utilities must file either an RTO proposal or a report on the impediments to RTO participation. In addition, to qualify as an RTO, an applicant must comply with the minimum characteristics and functions and other specific RTO requirements set forth in the new regulations. We will also expect that all transmission owners will participate in good faith in the collaborative process that we are establishing herein.

2. Organizational Form of an RTO

Comments. A number of commenters address the proposal to allow flexibility

[132] FERC Stats. and Regs. ¶ 32,541 at 33,685.

in the type of structure allowed for RTOs. Several of those commenting recommend maintaining the NOPR's flexibility and that the Commission not prescribe either a transco, ISO or some other structure.[133] FirstEnergy advocates flexibility and says that no one knows today what the best structure will be for the future so, therefore, the Commission should allow customization reflecting regional needs. Several commenters, such as APPA, argue that the Commission's flexibility on type of organization should go beyond the standard ISO and transco structures and include gridcos, wirecos, not-for-profit and for-profit forms of each organization, and hybrid organizations.

Numerous commenters state a preference in favor of for-profit transcos although many of these commenters still recommend that other structures be allowed at each region's option.[134] In favoring transcos, commenters cite the greater efficiency due to a transco's profit motive.[135] Commenters further argue that for-profit transcos can better serve the goal of independence because the transco would make all business decisions,[136] can more cleanly divide Commission-regulated transmission from state-regulated distribution,[137] and can operate more efficiently by integrating investment decisions, facility design, construction and O&M into a unified strategy.[138] A few additional supporters of transcos prefer that they be not-for-profit.[139] Gainesville recommends further that transcos in Florida become an instrumentality of the state.

In contrast to the above, ISOs are preferred by a number of commenters.[140] PJM argues that ISOs are necessary to ensure independence, provide more independent market monitoring and have a fiduciary duty to the public interest. PJM also notes that ISOs can meet the Commission's objectives more quickly than transcos. NASUCA reports that some of its members oppose for-profit transcos because of their ''natural incentive to extract monopoly rents from consumers.'' [141] Some of those who prefer ISOs contend that transcos would favor transmission solutions over generation solutions to congestion.[142] This argument is contested in the reply comments of Trans-Elect and others. NEPCO *et al.* maintains that the alleged bias in favor of transmission solutions can be overcome by using performance-based rates to replace standard rate base regulation.

Some commenters favor a hybrid involving an ISO with a gridco or with another type of organization.[143] As noted above, many commenters recommend flexibility and believe that either an ISO or transco would satisfy the needs of an RTO if designed properly.

Several commenters cited problems that need to be worked out for both transcos and ISOs. Professor Joskow notes that ISOs would suffer efficiency losses from the separation between ownership and operation of transmission assets. This separation makes it harder to apply incentive regulation because it divides decisions that affect the costs of transmission between two organizations. On the other hand, Professor Joskow says that an ISO may be superior to a transco where transmission ownership is presently so balkanized that loop flow and congestion cannot be managed, but he asserts that this advantage may decline over time as the industry changes. Southern Company says that while some see ISOs as ineffective bureaucracies which add to transmission risk, the creation of transcos presents substantial tax and financial problems.

A few commenters contend that the NOPR's provisions produce a bias in favor of ISOs even though this intent is not noted.[144] For example, Duke argues that the NOPR provisions for stakeholder participation in formation, governance and market monitoring functions seem more geared toward the ISO form of organization. These commenters recommend that the Final Rule not include such a bias.

A number of commenters suggest multi-layered structural alternatives. For example, ISO–NE proposes an ISO and gridco operating in tandem. A non-profit ISO would direct the operation of the transmission system and run day-ahead and real-time power markets coupled with a grid entity that owns and maintains the transmission in the area operated by the ISO. This, they claim, would require a final rule that defines an RTO as an entity, or a combination of entities working in collaboration, that satisfies the minimum characteristics set forth in the NOPR. Under the model discussed by ISO–NE, the ISO would have responsibility for assuring open transmission access, operating the regional transmission assets (including provision of switching orders to the gridco), monitoring power markets, serving as a clearing agent and possibly serving as a clearinghouse, and maintaining short-term reliability. The gridco would own and maintain transmission assets, operate transmission assets in response to ISO directions consistent with safety requirements, and build new transmission facilities (including licensing, permitting and siting responsibilities). Joint responsibilities would include planning upgrades to transmission system.

ISO–NE argues that ISOs alone would have disadvantages in the realm of transmission expansion due to fragmentation of transmission ownership. A gridco, however, could raise investment capital, bring parallel and complementary strengths to an ISO, and should bring crisp and decisive implementation of transmission planning and expansion decisions. Pairing an ISO with a gridco, ISO–NE argues, would eliminate the problems inherent in a transco by separating transmission ownership from market administration and market monitoring.

Midwest ISO suggests a structure that it believes could meld the best of both ISOs and transcos, *i.e.,* an ISO that would allow an independent transmission company to operate under the Midwest ISO. This model would not require that all transmission be owned by a single gridco—transmission owners could decide whether to operate directly through the ISO, or spin assets off to a gridco that would operate under the ISO. Midwest ISO argues that this proposal overcomes the problems encountered in expecting all transmission owners to divest their transmission assets to separate companies.

PGE points out that, ''for an RTO to achieve * * * critical mass in the near term, it must be capable of managing a regional transmission market in which a variety of subsidiary transmission structures will be in place. Such subsidiary structures may include single-company and sub-regional ITCs, integrated utilities located in states that already have restructured their retail electric markets, integrated utilities located in states that have not yet restructured, and publicly-owned and federal utilities.'' PJM argues that ISOs

[133] *See, e.g.,* EEI, Lincoln, LG&E, SERC and Washington Commission.

[134] *See, e.g.,* Allegheny, Entergy, INGAA and Trans-Elect.

[135] *See, e.g.,* Sierra Pacific, H.Q. Energy Services and Detroit Edison.

[136] MidAmerican.

[137] CTA.

[138] Duke.

[139] LPPC, Los Angeles, Gainesville and Public Citizen.

[140] *See, e.g.,* NASUCA, PJM and ICUA.

[141] NASUCA at 20.

[142] *See, e.g.,* PJM and ISO–NE.

[143] *See, e.g.,* ISO–NE.

[144] *See, e.g.,* Sierra Pacific, Duke and Enron/APX/Coral Power.

should be present even in regions that form separate transmission-owning companies to avoid continued conflict regarding the neutrality and commercial consequences of grid management decisions.

Professor Hogan states that it is very unlikely that a pure transco model is viable at all. He further indicates that, ''the advantages of an independent transmission company can be pursued through the gridco model with an accompanying ISO.'' He suggests that this approach is already well advanced in the United States and elsewhere, and that by separating ownership of the wires from control of system operations, it would be easy to accommodate a complex pattern of ownership.

ComEd says that characteristics and functions should be performed by two linked organizations that make up a binary RTO: a for-profit ITC under the oversight of an independent not-for-profit regional transmission board.

Michigan Commission believes that wirecos, transcos and ISOs are all interim transitional organizations along the path toward very large RTO-like organizations. Even if vestiges of the smaller interim organizations continue to exist, they should operate under some kind of RTO umbrella to assure appropriate regional control. Missouri Commission proposes a zonal model in which the zones are areas where generation is integrated through the transmission grid in such a way as to minimize restrictions on sources of generation used in the area. In the future, independent transmission companies may form with the possibility that adjacent control areas will join to form larger zones. In such a case, an RTO is a collection of zones for purposes of administering the regional gatekeeper function and providing markets for transmission congestion. Each zone would be responsible for maintaining its transmission facilities and coordinating both the use and expansion of those facilities with the RTO.

WEPCO proposes that each RTO should be composed of two parallel organizations to serve the same region under a common, independent board: a Regional Reliability Council to develop regional reliability rules and a not-for-profit ISO that operates under those regional rules.

Cal DWR suggests a three-tiered structure that builds on existing organizations. Existing NERC regional councils should set broad governing criteria for ISO reliability issues, parallel path flow issues, and for regional planning. More than one ISO may be located in each NERC region. These should control area reliability, administer transmission terms and conditions, and create market mechanisms to manage congestion, among other functions. Transmission owners should support, but not duplicate the roles of NERC regional councils.

Commission Conclusion. We will not limit the flexibility of proposed structures or forms of organization for RTOs. We are prepared to accept a transco, ISO, hybrid form, or other form as long as the RTO meets our minimum characteristics and functions and other requirements.

Some of the commenters argue that the NOPR's requirements either favor one form of organization over others or make one or the other forms very difficult to construct. It is not our intention to favor or disfavor transcos, ISOs, or other organizational form. We acknowledge that some of our minimum requirements might affect transcos and ISOs differently, but there also may be different acceptable ways for an ISO or transco to satisfy the minimum requirements. However, we designed this Final Rule to be neutral as to organizational form, and we do not believe that the requirements for forming an RTO in this Final Rule favor any particular RTO structure.

Arguments are made that an ISO is the better form of RTO because an ISO has no incentive either to favor transmission solutions to solve congestion constraints or to perpetuate congestion. ISOs are easier to form, in most cases, because there are fewer tax and mortgage consequences as there is no actual transfer of ownership.

On the other hand, some argue that transcos are preferable because they introduce a profit motive for efficient operation and expansion. Performance-based rates are normally considered more effective with transcos than with ISOs. Advantages are cited for having the same entity both propose and carry out transmission expansion and maintenance.

The transco and ISO forms of organization each has its advantages and disadvantages as do combination forms and other forms that have been suggested. In many cases, the situation facing transmission owners in a particular region may influence the appropriate form of organization to propose. In other cases it may be a matter of preference for how the participants wish to do business. Some may propose to start operation in one form and transform to another form at a future date. Tax consequences, public ownership, bond indentures and current organization will each have an impact on the decision of what form of organization a particular RTO will propose.

This Rule does not necessarily require that a single organization perform all of the functions itself. To mention but a few examples, we specifically clarify in other parts of this Final Rule that the security coordinator function and the OASIS function could be shared with another RTO or contracted out, and that appropriate scope may be achieved in creative ways. We will entertain appropriate tiered or other structures. We require only that the RTO be responsible for ensuring that the requirements are met in a way that satisfies our Rule.

Because of the differing conditions facing various regions, we offer flexibility in form of organization. We welcome innovative structures and forms that meet the needs of the market participants while satisfying the minimum requirements of this Rule.

3. Degree of Specificity in the Rule

Comments. Many commenters believe that our proposed flexible approach is either still too rigid, or that it should provide clearer guidance. INGAA argues for less specificity in the Final Rule. INGAA points to the success of Order No. 636, wherein the Commission required open access, functional unbundling, and a new rate design, and it established specific requirements for operational control and pipeline capacity trading, all without having to specify the structure of the conforming gas transmission entity. NU similarly points to the precedent of the restructured gas industry. It states that the Commission should avoid the perils of imposing a rigid system pursuant to the mistaken belief that it can be easily and swiftly changed later to respond to future needs of the marketplace. CP&L also cautions that the principle of flexibility could prove illusory in practice and that there is a danger that, if guidance from the Commission takes the form of overly restrictive rules, it will stifle the development of innovative proposals. PG&E submits that the Commission should simply define a broad standard that provides for independence and evaluate particular RTO proposals on a case-by-case basis. South Carolina Commission also counsels that the Commission should not attempt to mandate a particular form of RTO, or establish its size or region, because this will not ensure that an efficient market will develop. It posits that any RTO policy should be flexible enough and dynamic enough to allow for both regional and organizational differences and for growth and changes in the future.

SCE&G claims that the NOPR is overly prescriptive with respect to both scope and timing. TXU Electric submits that the NOPR's approach to reliance on minimum characteristics and functions seems to reflect a significant number of fundamental policy decisions that have already been made without the benefit of any of the very experimentation the NOPR extols. Southern Company argues that the Commission should recast the characteristics and functions as voluntary guidelines at this early stage in the development of RTOs, since it is unclear what the best form of RTO will be.

ISO supporters, such as NYPP and Central Maine, recommend that the Commission reject proposals to impose rigid and inflexible rules on RTOs and remain flexible especially with regard to existing ISOs and RTO pricing. ISO–NE counsels that tolerance for a diversity of approaches is essential, as well as politically pragmatic, due to the fact that different regions will have different histories, industry elements, and local regulatory policies that need to be accommodated.

FirstEnergy supports the NOPR's flexibility because there is no best model to deal with regional variations. Alliance Companies and Washington Commission also recommend that the Commission adhere to a flexible RTO policy, open to voluntary regional experimentation in the design of RTO structures. In addition, both Southern Company and Trans-Elect recommend that the Commission maintain flexibility toward transcos. And while a transco supporter, Entergy, sees the NOPR as properly flexible in regard to for-profit and not-for-profit RTOs. Finally, Duke agrees that RTOs should satisfy key principles, as long as they are not so prescriptive as to promote only one type of RTO.

On the other hand, Illinois Commission submits that the NOPR's minimalist approach will lead to creation of lowest common denominator RTOs that minimally comply with the characteristics and functions and general guidance as to geographic scope and membership. Project Groups suggests that the Commission expand and strengthen the minimum characteristics. TDU Systems recommends that the Commission resist calls to water down its Final Rule and urges more substance. TAPS claims that calls for more flexibility are really a cover for diluted, ineffective RTOs that will lack the scope, independence and authority to get the job done.

Commission Conclusion. While many commenters think that our proposal to rely on guidance and flexibility to promote establishment of appropriate RTOs is either too rigid or too non-specific, we conclude that we struck an appropriate balance in the NOPR.

Although we and the electric industry see many problems associated with the operation of the Nation's transmission systems and we see a general need for regional transmission solutions, we cannot at this time foresee the best organizational means to resolve every problem. Given this situation, we believe that the right balance is a minimally intrusive, solution-oriented approach that provides guidance and specifies only the fundamental RTO characteristics and functions.

We do not agree with those commenters who contend that the NOPR approach adopted herein is either overly or insufficiently prescriptive. Certainly the minimum characteristics and functions do reflect a number of threshold requirements, but collectively, these requirements serve to define the minimum necessary to improve the operation of the Nation's transmission systems. While we agree that there is no best answer and we encourage regional innovation, we cannot simply define a standard of independence and nothing else. This would leave the industry without direction and provides no guidance on how we would evaluate the various RTO proposals.

Finally, we do not agree with those who suggest that our electric regulation must follow our natural gas pipeline industry Order No. 636 model, where the Commission did not attempt structural unbundling of the pipeline industry but simply relied on more limited, functional unbundling. The situations in the two industries are different regarding the need for regional entities. Most importantly, there was not in the gas industry the degree of vertical integration of production, transmission, and distribution that historically existed in the electric industry. In addition, the gas industry has no analog to loop flow, transmission loading relief, the need for large regional calculations of ATC, or the use of generation energy and reactive power output to manipulate transmission flow, among other reasons.

4. Legal Authority

In the NOPR, we noted that sections 205 and 206 of the FPA, 16 U.S.C. 824d and 824e, give the Commission both the authority and responsibility to ensure that the rates, charges, classifications, and services of public utilities (and any rule, regulation, practice, or contract affecting any of these) are just and reasonable and not unduly discriminatory, and to remedy undue discrimination in the provision of such services. We stated that in fulfilling its responsibilities under FPA sections 205 and 206, the Commission is required to address, and has the authority to remedy, undue discrimination and anticompetitive effects.[145] We also noted that the Commission has the authority and responsibility under section 203 of the FPA to review mergers and other transactions involving public utilities, including dispositions of jurisdictional facilities by public utilities, and that the Commission may grant an application under section 203 upon such terms and conditions as it finds necessary to secure the maintenance of adequate service and the coordination in the public interest of jurisdictional facilities.

Further, we noted that section 202(a) of the FPA authorizes and directs the Commission ''to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy.'' The purpose of this division into regional districts is for ''assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources.'' Section 202(a) states that it is ''the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts.''

We solicited comments on whether the Commission should generically mandate RTO participation by all public utilities to remedy undue discrimination under sections 205 and 206 of the FPA, whether market-based rates for generation services could continue to be justified for a public utility that does not participate in an RTO, whether a merger involving a public utility that is not a member of an RTO would be consistent with the public interest, whether non-participants that own transmission facilities should be allowed to use the non-pancaked transmission rates of the RTO participants in that region, whether transmission services provided by a transmitting utility need to be under RTO control to satisfy the discrimination standards of sections 211 and 212 of the FPA, and whether a public utility's lack of participation

[145] FERC Stats. & Regs. ¶ 32,541 at 33,695.

would otherwise be in violation of the FPA.[146]

Comments. The comments on the Commission's legal authority to mandate participation in RTOs span the spectrum from those asserting that we clearly have that authority to those asserting that we clearly do not, with others taking a less definitive position in between.

Supporting Commission's Authority to Mandate RTO Participation. Representative of those asserting that the Commission has the authority to mandate RTO participation are the joint comments filed by APPA, ELCON, TAPS, and TDU Systems (''APPA *et al.* (WP)''). These parties argue that the FPA as presently constituted gives the Commission ''ample'' legal authority to require participation by public utilities in properly structured and configured RTOs. APPA *et al.* assert that section 202(a) permits the Commission to determine rational and efficient regional boundaries; section 203 provides authority to require RTO participation as a standardized condition to mitigate the increased generation and transmission concentration brought about by mergers; ''it would be fully consistent with, and indeed required by'' FPA section 205 to insist on RTO participation as a condition necessary to yield competition robust enough to produce just and reasonable market-based rates; requiring RTO participation falls within the Commission's broad discretion to fashion a remedy for undue discrimination under FPA sections 205 and 206; and the Commission could reasonably conclude that it is no longer just and reasonable for transmission service to be planned, implemented, or priced on a less-than-regional basis. Other commenters echo some or all of these points in asserting that the Commission currently has sufficient legal authority to mandate RTO participation.[147]

Some other commenters emphasize the authority contained in particular statutory sections. One commenter states that FPA section 202(a) is an express delegation of authority to the Commission to make policy, and the stated goal of that section of assuring an abundant supply of electric energy with the greatest possible economy provides ample authority to support the conclusion that transmission facilities should be operated by an RTO. This commenter states that it is well established administrative law that there is great deference given to an agency charged with policymaking responsibility.[148] Another commenter, FMPA, argues that the Commission's interconnection authority under FPA sections 202(b) and 210 provides ample basis for mandating RTO participation. According to FMPA, the Commission could find that RTO participation is necessary to ''make effective'' an interconnection, pursuant to FPA section 210, that has been rendered ineffective by fragmented and anticompetitive practices of transmission owners. FMPA also asserts that the Commission could use this authority through a rulemaking without following the individual procedural requirements of section 212.[149]

In addition to those commenters finding clear authority in the FPA for an RTO mandate, a number of commenters support the suggestion, as one commenter put it, that certain benefits and rights that are within the Commission's authority and discretion to grant or deny should be withheld from utilities unwilling to participate in an RTO.[150] PNGC states that the Commission should use ''big sticks'' to obtain RTO participation, and Michigan Commission says the Commission ''should use every stick, carrot, orange-colored stick and tool it can.'' Some commenters assert specifically that the Commission has the authority, and should use its authority, to condition mergers under section 203 and condition market-based rate authority under section 205 of the FPA on RTO participation.[151] Some commenters also favor limiting access to non-pancaked transmission rates of RTOs to those who participate in RTOs.[152]

Even some commenters that generally oppose the idea of an RTO mandate acknowledge that market-based rate authority or mergers could, on a case-by-case basis, be conditioned on RTO participation. For example, Florida Power Corp. states that the Commission could find, ''given certain factual circumstances,'' that the granting of market-based rate authority would not be appropriate ''unless the entity agreed to commit its transmission facilities to an RTO.'' United Illuminating states that whatever conditioning authority the Commission may have for market-based rates or mergers could not be used as a basis for a generic rulemaking.

NECPUC cites to other sections of the FPA that the Commission might rely upon to promote RTO establishment. It supports the use of the complaint process under section 206 of the FPA in specific cases. It also suggests the use of FPA section 207 proceedings, which can be initiated by state commissions, as a vehicle for requiring RTOs where the Commission finds interstate service inadequate or insufficient. NECPUC also urges the use of joint boards and cooperative procedures between the Commission and the states under FPA section 209 as a means of resolving RTO issues.

Opposing Commission's Authority to Mandate RTO Participation. At the other end of the debate on the Commission's legal authority with respect to RTOs are those that assert that the Commission's authority to mandate RTOs is non-existent or very limited.[153] A number of commenters emphasize that FPA section 202(a) is explicitly voluntary and therefore provides no support for the Commission's authority to mandate RTOs.[154] FP&L states that it is questionable whether the Commission could use FPA section 202(a) as a tool to promote competition, given that section 202(a) is for the ''coordination and interconnection of facilities,'' and coordination is arguably inconsistent with competition.

Some argue that the exercise of FPA section 206 authority to remedy discrimination on a generic basis by requiring RTOs would have to be supported by more explicit findings of discrimination than are contained in the NOPR.[155] For example, Florida Power Corp. and United Illuminating contend that the Commission cannot use an industry-wide solution to remedy a problem that does not exist industry-wide,[156] and the record does not demonstrate an industry-wide problem. EEI and others argue that the Commission may only impose a remedy that is reasonable and appropriate in light of the specific discriminatory

[146] *Id.* at 33,762.

[147] *E.g.,* UAMPS, PJM/NEPOOL Customers, Illinois Commission, Michigan Commission, Cinergy, Industrial Consumers, First Rochdale, East Texas Cooperatives, FMPA.

[148] Professor Koch, *citing* Chevron U.S.A., Inc. v. Natural Resources Defense Council Inc., 467 U.S. 837 (1984).

[149] *Citing* American Paper Institute, Inc. v. American Elec. Power Serv. Corp., 461 U.S. 402, 419–20 (1983).

[150] Oneok.

[151] *E.g.,* Oneok, TAPS, APPA, PJM/NEPOOL Customers, Illinois Commission, Industrial Consumers, East Texas Cooperatives, FMPA, TDU Systems and PNGC.

[152] *E.g.,* TDU Systems, PNGC and PJM/NEPOOL Customers.

[153] *E.g.,* Southern Company, Puget, Avista, CP&L, Duke, STDUG, FirstEnergy, NYPP, Indianapolis P&L, FP&L, Detroit Edison, Florida Power Corp., Florida Commission, Alabama Commission.

[154] *E.g.,* EEI, United Illuminating, Southern Company, Central Maine, CP&L, Duke, NYPP, Florida Power Corp., Florida Commission.

[155] *E.g.,* EEI, Central Maine, Southern Company, Duke, NYPP, Dalton Utilities, Indianapolis P&L, Florida Power Corp., Entergy.

[156] *Citing Associated Gas Distributors* v. *FERC,* 824 F.2d 981 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988).

findings made and the actual practices to be corrected, and the NOPR fails to demonstrate such a nexus. Southern Company notes that the Commission has not made any finding of discrimination and that the ''perception'' of discrimination is an insufficient basis on which to invoke FPA sections 205 and 206. CP&L asserts that section 206 may give the Commission some authority with respect to requiring RTOs, but only in individual cases after hearings and substantial evidence of discriminatory practices. Southern Company contends that the Commission's remedial authority under section 206 must be construed in light of the voluntary nature of section 202(a) and the Commission cannot do anything indirectly under section 206 that it cannot do directly under section 202(a). Central Maine asserts that discrimination findings would not apply against a ''wires only'' company such as itself, and similarly, Indianapolis P&L argues that it has no ability to discriminate in favor of its own wholesale generation and therefore could not be forced to join an RTO as a remedy for discrimination.

Some commenters question the Commission's authority to condition market-based rates or mergers on RTO participation. Central Maine argues that the Commission could not conclude on a generic basis that an RTO is needed in every market-based rate case, and that the Commission could not change its existing policy on market-based rates without substantial evidence and reasoned decisionmaking. CP&L states that the Commission cannot use FPA section 205 authority to grant market-based rates merely to advance preferred policies, and cannot use FPA section 203 to condition mergers absent specific findings in a particular case. Duke contends that the Commission has no authority to issue a rule that imposes sanctions for non-participation that would make non-participation practically or economically unfeasible. Similarly, NYPP states that mergers, market-based rates, and access to non-pancaked transmission rates are economic necessities, and using them as conditions would effectively require RTO participation. Indianapolis P&L asserts that it would be inequitable and unjustifiable to withhold market-based rate authority from a utility that has a good reason not to participate in an RTO, and further, that the Commission may not pressure a utility to engage in an activity that it may not require through direct regulation.[157] Similarly, Puget states that if the Commission is not mandating RTOs, which is beyond its authority, then the rule must contain no penalties for non-participation.

Several commenters point to the recent court decision in *Northern States*[158] as limiting the Commission's authority with respect to RTOs.[159] These parties assert that *Northern States* stands for the proposition that the Commission may not directly or indirectly interfere with state regulation of retail service, and that the NOPR would result in traditional utility retail responsibilities being shifted to RTOs. Specifically, for example, Puget alleges that redispatch and planned maintenance are reliability functions that affect the utility's ability to serve native load and are subject to state law. Indianapolis P&L asserts that *Northern States* makes clear that the Commission may act only under authority given by Congress.

A variety of other legal arguments are made in opposition to any Commission efforts to mandate RTO participation. Southern Company contends that since there has been no finding that Order Nos. 888 and 889 have failed, there has been no reasonable explanation as to why the Commission should change that policy. CP&L argues that the Commission's authority to enforce FPA section 205 is in the enforcement provisions of FPA sections 314, 316, and 317. CP&L also states that it would be discriminatory to have higher pancaked rates for non-participants in RTOs while participants get the advantage of non-pancaked rates. Duke and Florida Power Corp. assert that requiring involuntary wheeling and imposing common carrier status is outside the Commission's authority,[160] and likewise, so is mandating RTOs. Florida Power Corp. contends that requiring RTO participation would force a utility to join an ISO or divest its transmission or generation assets, and the Commission cannot compel divestiture. Florida Power Corp. and Southern Company make the point that the Public Utility Holding Company Act granted the SEC, not the FERC, the authority to restructure the electric utility industry. Florida Power Corp. further argues that requiring RTO participation would be a ''taking'' of utility property for which just compensation would be owed, and that the ''taking'' problem is exacerbated by utilities being liable for facilities no longer under their control. Florida Commission states that the Energy Policy Act of 1992 indicated that the Commission should proceed with transmission access issues case-by-case, not generically.

Other Comments On Legal Authority. DOE submitted comments strongly supporting the Commission's efforts to establish RTOs. DOE states that while the Commission has substantial authority to accomplish much of what needs to be done, Federal legislation clarifying Commission authority, especially with respect to non-jurisdictional utilities, would greatly facilitate RTO formation.

One commenter raised the issue of what authority the Commission would rely upon to require the filings in proposed section 35.34(c). This commenter wants the Commission to clarify that the filings would be required pursuant to the information gathering authority under FPA sections 304, 307, and 311, and not under authority of section 205, which the commenter asserts provides no such authority.[161]

There were only a few comments in response to the Commission's inquiry about sections 211 and 212 or other FPA standards. Florida Power Corp. submits that the Commission cannot rely on FPA sections 211 and 212 to mandate RTOs. Florida Power Corp. notes that in Order Nos. 888 and 888–A, the Commission recognized that it does not have the authority to order wheeling pursuant to FPA sections 211 and 212 except on a case-by-case basis after an evidentiary hearing resulting in specific findings. Florida Power Corp. argues that because the Commission is fashioning an industry-wide generic solution and not acting on a case-by-case basis, the Commission cannot rely on sections 211 and 212 in this proceeding.

NARUC also notes that Congress revised FPA sections 211 and 212 to provide FERC with authority to address requests for non-discriminatory transmission service on a case-by-case basis. NARUC argues that the goal of promoting regional flexibility is more readily served by case-by-case consideration. In this way, NARUC believes that the Commission can use FPA sections 211 and 212 to take a more tailored approach rather than ''one-size-fits-all'' regulations that ignore market development and local conditions.

Commission Conclusion. Much of the discussion in the comments on the Commission's legal authority with

[157] *Citing Altamont Gas Transmission Co.,* v. *FERC,* 92 F.3d 1239, 1246 (D.C. Cir. 1996).

[158] *See Northern States, supra* note 89.

[159] *E.g.,* Southern Company, Puget, Indianapolis P&L, FP&L, Florida Commission.

[160] *Citing* Richmond Power & Light Co. v. FERC, 574 F.2d 610 (D.C. Cir. 1978) and Otter Tail Power Co. v. U.S., 410 U.S. 366 (1973).

[161] Consumers Energy.

respect to RTOs focuses on whether the Commission has the statutory authority to mandate that transmission owners participate in an RTO. As discussed elsewhere in this Final Rule, we have decided not to mandate generically that all public utility transmission owners must join an RTO. We conclude that the Commission possesses both general and specific authorities to advance voluntary RTO formation. We also conclude that the Commission possesses the authority to order RTO participation on a case-by-case basis, if necessary, to remedy undue discrimination or anticompetitive effects where supported by the record.[162] Of course, RTO participation is not the only remedy that the Commission might employ to address these problems.

FPA sections 205 and 206. As we stated in the NOPR, the Commission is granted the authority and responsibility by FPA sections 205 and 206, 16 U.S.C. 824d and 824e, to ensure that the rates, charges, classifications, and service of public utilities (and any rule, regulation, practice, or contract affecting any of these) are just and reasonable and not unduly discriminatory, and to remedy undue discrimination in the provision of such services. In fulfilling its responsibilities under FPA sections 205 and 206, the Commission is required to address, and has the authority to remedy, undue discrimination and anticompetitive effects. The Commission has a statutory mandate under these sections to ensure that transmission in interstate commerce and rates, contracts, and practices affecting transmission services, do not reflect an undue preference or advantage (or undue prejudice or disadvantage) and are just, reasonable, and not unduly discriminatory or preferential.[163] Additionally, as discussed in Order No. 888,[164] there is a substantial body of case law that holds that the Commission's regulatory authority under the FPA ''clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to [FPA] sections 202 and 203, and under like directives contained in sections 205, 206, and 207.'' [165]

There are two principal contexts in which the authority of FPA sections 205 and 206 has been raised. One is the use of requiring participation in RTOs as a remedy for undue discrimination by public utilities. As discussed above, many commenters believe that the evidence of undue discrimination is sufficient to justify generically mandating RTO participation as a remedy, and many others argue that the record on undue discrimination is insufficient to impose a generic, industry-wide solution. We have concluded in our discussion elsewhere in this Rule that continuing opportunities for undue discrimination exist in the electric transmission industry. However, we have also concluded that a voluntary approach to eliminating such opportunities through RTO formation (including the filing requirements and Commission supported collaboration efforts identified herein) represents a measured and appropriate response to the significant undue discrimination and other competitive impediments identified in this record.

The other context in which our authority under FPA sections 205 and 206 is raised is whether permitting a public utility to charge market-based rates for wholesale electricity sales can continue to be justified if the seller or its affiliate owns or operates transmission assets that have not been placed under the control of an RTO. The Commission has a responsibility under FPA sections 205 and 206 to ensure that rates for wholesale power sales are just and reasonable, and has found that market-based rates can be just and reasonable where the seller has no market power. The Commission has determined that to show a lack of market power, the seller and its affiliates must not have, or must have adequately mitigated, market power in the generation and transmission of electric energy, and cannot erect other barriers to entry by potential competitors.[166] In the past, the Commission has found that an open access transmission tariff mitigated transmission market power.[167]

As discussed above, some commenters believe that the Commission should insist upon RTO participation as a condition necessary to yield competition robust enough to support market-based rates, while others argue that we cannot use market-based rate authority to advance preferred policies or as a penalty. We are not adopting in this Final Rule a generic policy that participation in an RTO is a necessary condition to a public utility receiving, or retaining, market-based rate authority, nor do we propose to use the denial of market-based rate authority as a penalty for not voluntarily complying with this Rule. However, we do have an obligation to ensure that rates for wholesale power sales are just and reasonable, and we adhere to our precedent that market-based rates can be just and reasonable only where transmission market power has been mitigated and there are no other barriers to entry.

FPA section 202(a) and PURPA section 205. Section 202(a) of the FPA, the authority for which has been delegated to the Commission by the Secretary of Energy,[168] authorizes and directs the Commission ''to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy.'' The purpose of this division into regional districts is for ''assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources.'' Section 202(a) of the FPA states that it is ''the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts.''

Some commenters assert that FPA section 202(a) gives us broad authority and discretion to promote RTOs to support an abundant supply of electric energy with the greatest possible economy, while others contend that the authority is limited by the ''voluntary'' nature of the provision. We need not decide the precise confines of section 202(a) authority here. Clearly, this section gives the Commission the authority, after consultation with state commissions, to establish boundaries for regional districts for the voluntary interconnection and coordination of

[162] We need not decide in this case the extent of the Commission's authority to mandate generically RTO participation.

[163] Once such a finding is made, the Commission is required to remedy it. *See, e.g.,* Southern California Edison Company, 40 FERC ¶ 61,371 at 62,151–52 (1987), *order on reh'g,* 50 FERC ¶ 61,275 at 61,873 (1990), *modified sub nom.,* Cities of *Anaheim* v. *FERC,* 941 F.2d 1234 (D.C. Cir. 1991); Delmarva Power and Light Company, 24 FERC ¶ 61,199 at 61,466, *order on reh'g,* 24 FERC ¶ 61,380 (1983).

[164] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,669.

[165] *Gulf States Utilities Co.* v. *FPC,* 411 U.S. 747, 758–59, *reh'g denied,* 412 U.S. 944 (1973). *See City of Huntingburg* v. *FPC,* 498 F.2d 778, 783–84 (D.C. Cir. 1974) (Commission has a duty to consider the potential anticompetitive effects of a proposed Interconnection Agreement.)

[166] *See, e.g.,* Heartland Energy Services, Inc., 68 FERC ¶ 61,233 at 62,060 (1994); Louisville Gas & Electric Company, 62 FERC ¶ 61,016 at 61,143–44 (1993) *(Heartland). See also Louisiana Energy and Power Authority* v. *FERC,* 141 F.3d 364 (D.C. Cir. 1998) (court upholds Commission's use of market-based rate authority).

[167] *See, e.g., Heartland,* 68 FERC at 62,061, 62,063–64.

[168] 63 FR 53889 (Oct. 7, 1998).

facilities in order to assure an abundant supply of electric energy with the greatest possible economy. We have decided in this Rule that we will exercise this authority, at least in the first instance, by allowing transmission owners, in consultation with other interested parties and state commissions, to propose to us what they believe to be appropriate regional districts. In this regard, we conclude that the Commission, pursuant to FPA section 202(a), clearly has the authority to direct public utilities as well as non-public utilities [169] to *consider* the regional coordination that would result from joining an RTO and to participate in Commission-sanctioned RTO discussions.

As we are not in this Final Rule mandating any particular interconnection or coordination of facilities, we need not address whether the language in FPA section 202(a) referring to ''voluntary'' interconnection and coordination limits our authority. It is clearly the intent and requirement of this section that the Commission encourage and promote a regional approach, which is what we are doing in this Final Rule.

Section 205 of PURPA [170] also supports the Commission's authority to encourage and promote regional coordination. This section, which addresses power pooling, gives the Commission the authority to exempt electric utilities from state laws or regulations which prohibit or prevent voluntary coordination, and to recommend to electric utilities to enter voluntarily into negotiations for pooling arrangements where opportunities for conservation, efficiency, and increased reliability exist. The Commission has previously interpreted section 205 of PURPA as essentially complementing the functions under section 202(a).[171]

FPA Section 203. The Commission has the authority and responsibility under section 203 of the FPA to review mergers and other transactions involving public utilities, including dispositions of jurisdictional facilities by public utilities. There are two aspects of this authority that relate to RTO formation. First, public utilities' transfers of control of jurisdictional transmission facilities to entities such as RTOs would require section 203 approval. Under section 203 of the FPA, the Commission must approve a proposed disposition of jurisdictional facilities if it is consistent with the public interest.

Second, the Commission may grant an application under section 203 upon such terms and conditions as it finds necessary to secure the maintenance of adequate service and the coordination in the public interest of jurisdictional facilities. FPA section 203(b) explicitly gives the Commission authority to condition a public utility's proposed disposition of jurisdictional assets ''upon such terms and conditions as it finds necessary or appropriate to secure the maintenance of adequate service and the coordination in the public interest of facilities subject to the jurisdiction of the Commission.'' Thus, for instance, the Commission has used section 203 conditioning authority to require that all mergers be conditioned on the offer of comparable open access transmission.[172] In the Commission's Merger Policy Statement, it was recognized that the development of fully competitive generation markets is in the public interest and that turning over control of transmission assets to an ISO might be an appropriate remedy for anticompetitive effects of a merger.[173]

Some commenters urge the Commission to make RTO participation a standardized condition to all mergers in order to mitigate increased generation and transmission concentration, while others claim that RTO imposition as a section 203 condition would require specific findings in a particular case. We do not find as a generic matter in this proceeding that no merger could be consistent with the public interest in the absence of RTO participation. However, as noted in the Merger Policy Statement with respect to ISOs, turning control of transmission assets over to an RTO might be an appropriate remedy for the anticompetitive effects of a merger. In general, our processing of merger applications can be facilitated to the extent the merging parties have resolved potential anticompetitive issues through means such as RTO participation.

Other Legal Issues. Commenters have suggested other statutory authorities that may be relevant to our efforts to encourage RTOs. These include FPA section 207, which upon state commission complaint authorizes the Commission to remedy inadequate or insufficient interstate service; FPA sections 202(b) and 210, which address the Commission's authority to order interconnections and make effective an interconnection; FPA section 209, which authorizes the Commission to refer matters to joint boards composed of Commission and state representatives; and FPA sections 211 and 212, which address the Commission's authority to require transmission services. We agree that, under appropriate circumstances, these authorities may indeed be relevant to RTO formation. However, we do not, and need not, rely upon them for what we are requiring in this Final Rule, so we will not address here what authority they might confer.

In response to those commenters who assert that the *Northern States* [174] court decision somehow limits our authority with respect to RTOs, we disagree. As reflected in our recently issued order on remand [175] of the *Northern States* court decision, that decision addresses narrow circumstances involving transmission curtailment where the third-party transmission customer has redispatch options. We do not interpret the decision as limiting our authority to encourage or require RTO participation. Moreover, we note that formation of RTOs is likely to eliminate or significantly reduce the potential for the type of conflict encountered in *Northern States.*

With respect to the commenter seeking clarification of the authorities we are relying upon to require the filings we are mandating in this Rule, we clarify that we are relying upon the authorities contained in FPA sections 202(a), 304, 307, and 309 for the filings we are requiring under new sections 35.34(c) and (g). To the extent a public utility proposes to participate in an RTO, we will process that application pursuant to FPA sections 203, 205 or other sections as appropriate.

D. Minimum Characteristics of an RTO

In the NOPR, we proposed minimum characteristics and functions for a transmission entity to qualify as an

[169] The legislative history, as well as the Commission's past use of section 202(a), indicates that the provision applies to both public utilities and non-public utilities. *See* S. Rep. No. 621, at 49 (1935) (''public as well as private plants are included''); Reliability and Adequacy of Electric Service, Order No. 383, 41 FPC 846,47 (1969) (information on coordination requested pursuant to section 202(a) from public and non-public utilities).

[170] 16 U.S.C. 824a–1.

[171] In *Public Service Company of New Mexico,* 25 FERC ¶ 61,469 at 62,038 (1983), the Commission stated that, ''Our mandate under PURPA to promote voluntary coordination is similar to that exercised by our predecessor, the Federal Power Commission, for more than 40 years under Section 202(a) of the Federal Power Act.'' *Accord* Pacific Gas and Electric Company, 38 FERC ¶ 61,242 at 61,791 (1987) (PURPA ''reaffirms the Commission's authority to promote voluntary coordination of electric utilities'').

[172] El Paso Electric Company and South West Services, 68 FERC ¶ 61,181 at 61,914–15 (1994), *dismissed,* 72 FERC ¶ 61,292 (1995).

[173] Inquiry Concerning the Commission's Merger Policy Under The Federal Power Act, 61 FR 68595 (Dec. 30, 1996), FERC Stats. & Regs. ¶ 31,044 at 30,115, 30,121, 30,137 (1996).

[174] *See Northern States, supra* note 89.

[175] Northern States Power Co. (Minnesota) and Northern States Power Co. (Wisconsin), 89 FERC ¶ 61,178 (1999).

RTO. These characteristics and functions are designed to ensure that any RTO will be independent and able to provide reliable, non-discriminatory and efficiently priced transmission service to support competitive regional bulk power markets. In the section that follows, we discuss the four minimum characteristics for an RTO, which are:

(1) Independence from market participants;

(2) Appropriate scope and regional configuration;

(3) Possession of operational authority for all transmission facilities under the RTO's control; and

(4) Exclusive authority to maintain short-term reliability.

In our discussion below, we clarify and revise to some extent our discussion in the NOPR, but we affirm these as the minimum characteristics of an RTO.

1. Independence (Characteristic 1)

As a first required characteristic, the Commission stated that all RTOs must be independent of market participants. To achieve independence, we proposed that RTOs must satisfy three conditions. First, the RTO, its employees, and any non-stakeholder directors must not have any financial interests in any market participants.[176] Second, the RTO must have a decision-making process that is independent of control by any market participant or class of participants.[177] The NOPR defined market participant as any entity or its affiliate that buys or sells electric energy in the RTO's region or in any neighboring region that might be affected by the RTO's actions. We said that this second condition would be judged on a case-by-case basis. However, the Commission also proposed, by way of example, that an RTO could satisfy this second condition with (a) a non-stakeholder governing board and (b) a prohibition on market participants having more than a *de minimis* (one percent) ownership interest in the RTO. Third, the RTO must have exclusive and independent authority to file changes to its transmission tariff with the Commission under section 205 of the FPA.[178]

Comments. A large number of commenters address different facets of the independence characteristic. To make the summary of comments more manageable, we grouped the comments by key sub-issues: the basic principle; who is a market participant; RTO economic interests in market participants and energy markets; voting interests of one market participant and affiliates; voting interests of classes of market participants; passive ownership interests; RTO governing boards; role of state agencies; and section 205 filing rights.

The Basic Independence Principle. In the NOPR, the Commission reiterated its earlier statement that ''the principle of independence is the bedrock upon which the ISO must be built'' and that this standard should apply to all RTOs, whether they are ISOs, transcos or variants of the two.[179] Virtually all commenters agree with this principle. For example, EEI states that ''[a] decisionmaking process independent of the control of any market participant or class of market participants should be an important aspect of the independence principle.'' [180] The TDU Systems say that ''[f]ull independence is vitally important to the success of RTOs * * * and cannot be safely compromised.'' [181] The Nine Commissions urge that RTOs must be ''truly independent of market participants in word, deed and appearance.'' [182] Despite the almost unanimous acceptance of the principle, there are fundamental disagreements (discussed in later sections) among commenters as to how the principle should be implemented, especially for RTOs that would operate as stand alone, for-profit transcos.

Some commenters question whether complete independence comes at too high a cost. For example, FP&L recommends that the Commission ''not consider independence in a vacuum.'' It contends that ''it would make little sense to trade off the greatest degree of independence for the highest cost structure.'' [183] Salomon Smith Barney makes a similar point. It contends that strict application of the independence standard could thwart the development of for-profit RTOs. Therefore, it urges the Commission ''not to promulgate rules that maintain absolute purity but also throttle the * * * voluntary formation of RTOs.'' [184] Konoglie/Ford/Fleishman, three individuals from the financial community, express concern that independence will usually be interpreted to mean a separation between ownership and control as currently practiced in ISOs. They argue that, if the ISO model becomes the norm, it could lead to higher capital costs because those who own the transmission assets would not be able to make basic investment and operating decisions. They point out that ownership usually imparts control in most U.S. industries and that transmission operating and investment efficiencies are unlikely to be achieved unless this becomes the norm in a restructured U.S. electricity industry.

PJM and WEPCO contend that a for-profit transmission company can never be independent because it will always be biased in its operating and investment decisions. Specifically, they assert that a for-profit transco will always be biased toward transmission solutions over other solutions (such as generation redispatch) and its own transmission assets over transmission assets owned by others. WEPCO, therefore, concludes that independence can be achieved only if there is an ISO operating over a for-profit transmission company.[185]

Other commenters argue that it would be naive to believe that independence, by itself, will lead to an effective RTO. They argue that an RTO may be completely independent but it must also have sufficient operational and decisionmaking authority if it is to be effective. For example, the TDU Systems assert that independence will not be sufficient if transmission owners attempt to reserve certain decisions for themselves. It points to the transco proposals of the Entergy and the Alliance Companies as examples of a proposed RTO having insufficient decisionmaking authority. NECPUC, representing six New England commissions, argues that an RTO must have independent funding and urges the Commission to include this as an explicit requirement in the final rule. NCPA states that an RTO will not be truly independent unless it is able to make and implement independent procurement decisions.

Who Is a Market Participant? There is substantial disagreement among commenters about the proposed definition of market participant. Some commenters argue that it should be expanded; others contend that it should be narrowed. In the first group, Illinois Commission urges us to expand the definition of a stakeholder because ''[a] market interest can arise through functions and activities other than just buying or selling electricity.'' [186] Enron/APX/Coral Power echo this point and contend that an RTO should ''not be subject to control by, and has no interest in the success of any vendor or buyer in the competitive functions of the

[176] FERC Stats. & Regs. ¶ 32,541 at 33,726.

[177] *Id.* at 33,727.

[178] *Id.* at 33,729.

[179] *Id.* at 33,726.

[180] EEI at 25.

[181] TDU Systems at 41.

[182] Nine Commissions at 8.

[183] FP&L at 32.

[184] Salomon Smith Barney at 5.

[185] WEPCO at 9.

[186] Illinois Commission at 29.

industry.'' [187] Duke recommends expanding the definition to include ''any distribution company or neighboring transmission company and/or any buyer or seller of ancillary services.'' [188] PJM urges that the definition of a market participant include any entity that owns transmission facilities or provides or buys transmission service.[189]

TAPS, representing an informal group of transmission dependent utilities in 24 states, also urges us to adopt a broad definition of market participant to ensure RTO neutrality. It argues that millions of dollars of investments and operating costs will be affected by RTO decisions. It gives several examples of how RTO decisions can have major economic impacts. As a transmission planner, an RTO will have substantial responsibility for routing new transmission lines. Depending on its decisions, it can help or hurt one gas pipeline or another or one generator or another. As a transmission tariff administrator, it will have significant discretion in choosing how to price congestion. Any decision that it makes (*e.g.,* zonal versus nodal pricing) could have significant impacts on the profitability of particular generators. As the supplier of last resort for ancillary services, it will have considerable discretion in defining the types and quantities of ancillary services that are needed. Depending on its decisions, some generators ''will win, and others will lose.'' [190] Finally, as the ''transmission-request gatekeeper,'' it will have substantial influence on who gets service and on what terms. To ensure both the appearance and reality of neutrality in these various decisions, TAPS urges us to adopt a broad definition of market participant.

In contrast, others contend that the proposed definition is too broad. CP&L states that a literal application of the proposed definition ''would make every single residential, commercial, industrial and wholesale electric customer (and all of their affiliates) market participants.'' [191] It recommends that the definition be narrowed by changing it to ''those entities that are active in wholesale and non-regulated retail power markets using transmission of the RTO.'' [192] LPPC asks that the Commission define the term ''affiliate'' because it is not defined anywhere in the NOPR. It also suggests that the definition of affiliate be limited to ''common control'' rather than using the five-percent ownership interest standard of PUHCA.[193]

A number of commenters focus specifically on the question of whether a ''distribution only'' entity (*i.e.,* an entity that performs the sole function of transporting electricity at distribution voltages) should be considered a market participant. Montana Power urges us against expanding the definition to include an entity that operates ''distribution-only facilities.'' It argues that an RTO and a distribution entity are both ''delivery entities'' and efficiencies can be gained by having one entity provide ''total delivery service'' from high to low voltages. These efficiencies of vertical integration could include the savings that would result from having maintenance performed on both transmission and distribution facilities by the same crews, the sharing of shop and warehouse space and the sharing of various administrative support functions. Sierra Pacific generally supports this view and asserts that it does not believe that a ''transmission owner could so operate its facilities to materially assist affiliated transmission and distribution interests to the disadvantage of unaffiliated entities.'' [194]

Salomon Smith Barney takes a more cautious view. It states that an RTO owned by distribution entities ''could manipulate the grid to favor their customers over the customers of other distributors.'' [195] Trans-Elect argues that the Commission's recent attempt to impose non-discriminatory curtailment procedures on all users of the grid in the NSP service territory demonstrates that this problem already exists.[196] Arguing that it would be undesirable to lose distribution entities as potential investors in RTOs, Salomon Smith Barney recommends that the Commission require RTOs to follow market-based priority rules in curtailment situations to reduce the likelihood that an RTO would favor affiliated distribution entities.

Both Sierra Pacific and NEPCO *et al.* raise concerns about the interaction of the market participant definition and ''state-mandated backstop power supply obligations.'' NEPCO *et al.* asserts that all 23 states that have opted for retail competition to date have usually imposed a default supplier obligation (which also is referred to as a ''standard offer supplier'' or a '' provider of last resort'' obligation) on one party which is usually the incumbent provider. Sierra Pacific notes that the nature and duration of this mandated obligation varies from state-to-state ''but at least some of the programs are structured so that the POLR [provider of last resort] does not compete for new customers and has no incentive to retain existing POLR customers.'' [197] Both commenters argue that providers of last resort should not automatically be considered as market participants, even though they buy and sell electricity, because this would reduce the pool of potential transco investors. Sierra Pacific states that the Commission should ''leave the door open to consider the POLR issue on a case-by-case basis'' and that the final regulations should explicitly say that a provider of last resort would not be deemed a market participant if its state mandated obligation gives it no incentive to make such sales.[198]

Finally, NEPCO *et al.* raises the issue of incumbent utilities that have tried to divest themselves of their generating assets but have not yet succeeded. It points to its difficulties in divesting its minority ownership interests in nuclear plants. It requests that an entity not be automatically deemed a market participant because of these minority ownership interests especially if it has taken actions to eliminate its control over the retained ownership interest (*e.g.,* through a long-term contract that would give marketing rights to a non-affiliated entity).

RTO Economic Interests in Market Participants and Energy Markets. Many commenters, representing a wide range of industry constituencies, agree with the NOPR's proposal that the RTO, its employees and any non-stakeholder directors must not have any financial interests in electricity market participants.[199] Duke recommends that, where divestment is required, the Commission should continue its past practice of allowing employees to divest personal investments in a manner that

[187] Enron/APX/Coral Power at 8.

[188] *See* Duke Power at 27. *See also* Midwest Municipals, Avista and American Forest.

[189] United Illuminating disagrees. It asserts that ''transmission owners without power marketing interests'' should not be considered as market participants. United Illuminating at 37.

[190] TAPS at 63.

[191] CP&L at 23–24. American Forest believes that ''the Commission did not intend such a broad exclusion, and seeks clarification on this point.'' American Forest at 4.

[192] CP&L at 23–24.

[193] LPPC points out that the term ''affiliate'' is used in defining market participant but is not defined anywhere in the proposed rule.

[194] Sierra Pacific at 17.

[195] Salomon Smith Barney at 5.

[196] Trans-Elect at 5 *citing* Northern States Power Co. v. FERC, 176 F.3d 1090 (8th Cir. 1999).

[197] Sierra Pacific at 16.

[198] *Id.*

[199] One exception is Salomon Smith Barney. It argues that this requirement is ''altogether unreasonable, in that it could require the most qualified directors and employees to dispose of mutual funds, pension plans and old investments whose tax base makes disposition unreasonable.'' Salomon Smith Barney at 3.

does not cause them significant financial harm.

Most commenters agree that the focus should be on current financial interests.[200] Several commenters point out that it would be virtually impossible for an RTO to hire knowledgeable and experienced employees if the Commission were to require no past financial connections to market participants. They assert that some of the most knowledgeable candidates for RTO positions, at least in an RTO's early years of operation, are likely to be individuals who have retired from companies that are market participants and it is likely that these individuals will be receiving pensions from their former employers. In situations like this, NASUCA urges the Commission to ''exclude from this prohibition * * * employee pension plans and other post-employment benefits received while a former employee of a market participant.'' [201] Others urge that the Commission follow the precedent that was established in the Midwest ISO decision.[202] Individuals would not be automatically excluded from RTO employment or directorships if their pension does not directly depend on the economic performance of their former employers (*e.g.,* a defined benefit pension plan). TDU Systems suggests that reasonable exceptions should be made ''in the case of defined benefit pension plans, general mutual funds (as opposed to utility/energy sector funds) that hold stock or bonds of market participants, or other similar financial holdings where the holder cannot direct specific investments or benefit directly from stock performance.'' [203]

In the NOPR, we asked whether there was a need to ''define the financial independence requirement in more specific terms.'' [204] The answer from almost all respondents was ''no.'' For example, TDU Systems recommend that we issue a general rule with a set of guidelines and then allow for its application on a case-by-case basis. Avista agrees and states that any financial independence standard ''require[s] case-by-case consideration as well as the common sense application of the rule of reason.'' [205] PJM/NEPOOL Customers states that RTOs will have the benefit of the conflict of interest standards that have been drafted for each of the functioning ISOs. They also recommend that the Commission commence a separate rulemaking on this issue.

Some commenters contend that the NOPR's treatment of financial independence is too narrowly drawn. For example, Dynegy argues that while ISOs ''may ostensibly be independent of market participants—they are not independent of the market itself.'' [206] As evidence of this phenomenon, it points to instances when the California ISO has tried to impose price caps on energy prices. EPSA expresses a similar view and points to the price caps proposed by ISO New England and approved by this Commission during the June 1999 heat wave, when energy prices reached $1,600 a megawatt-hour, as another example of undesirable and inappropriate intervention by a transmission provider in energy markets. In crafting a definition of independence, EPSA urges the Commission to require that RTOs ''should be indifferent to the price at which the commodity they transport clears the market.'' [207]

Others argue that this conflict is unavoidable as long as the Commission imposes a requirement that RTOs be the supplier of last resort for certain ancillary services.[208] According to these commenters, this obligation will often require that the RTO be a buyer in certain ancillary service markets. If the supplier of last resort obligation is also combined with a requirement that the RTO buy efficiently, then it is inevitable that the RTO will be interested in whether the prices are high or low (*i.e.,* it is no longer simply a disinterested market operator).

Active (Voting) Ownership Interests in the RTO. a. By Individual Market Participants and Their Affiliates. A number of commenters oppose a one-percent cap on allowed voting interests of market participants in RTOs as a necessary requirement for achieving independence.[209] EEI states that such a cap is not ''necessary, rational or supportable'' for achieving the goal of independence.[210] It recommends that the Commission allow market participants or their affiliates to own up to ten-percent voting interests in RTOs. EEI also asks for a clarification of whether an ownership restriction would ''apply only to ownership in the RTO itself or does it also apply to ownership interests in the transmission facilities under the operational control of the RTO.'' [211] PJM, which is organized as a non-profit limited liability corporation (LLC), asks the Commission to clarify whether its ''members'' would be considered owners.

CTA also argues for a higher cap. It states that the NOPR's emphasis on ownership is misplaced. Instead, the Commission should be concerned with the ''actual control over the day-to-day affairs of the system, not some arbitrary percent ownership test.'' [212] The Alliance Companies express the concern that, even though the one percent cap appears to have been proposed as a ''safe harbor,'' it could quickly become ''the only port of entry to Commission approval.'' [213]

EEI observes that other government agencies allow five or ten percent ownership in voting shares before assuming that these ownership interests conveyed control.[214] For example, it notes that the SEC definition of an ''affiliate'' under PUHCA is limited to entities that own or control more than five percent of the voting stock of a public utility. It also observes that this Commission, in determining whether a company is an affiliate of a natural gas pipeline or an electric utility, applies a rebuttable presumption of control only when a utility owns ten percent or more of a company's voting stock. Entergy states that ''there do not appear to be instances under U.S. law where one-percent ownership is considered to give rise to a risk of control.'' [215]

Several commenters question why there should be any limits on the amount of voting shares that can be held by a market participant. For example, Allegheny asserts that ''[t]he desire to maintain or obtain ownership of transmission assets by market participants should not be regarded as an evil to be avoided at all costs.'' [216] FP&L states that there is no need to

[200] With respect to future financial interests, Salomon Smith Barney states that ''[p]rivate enterprises do not normally, control the lives of their ex-employees.'' Salomon Smith Barney at 3.

[201] NASUCA at 17.

[202] *See* Midwest Independent System Operator, 85 FERC ¶ 61,250 (1998). *See also* Southern Company, Duke, TDU Systems and Avista.

[203] TDU Systems at 39.

[204] FERC Stats. & Regs. ¶ 32,541 at 33,727.

[205] Avista at 11.

[206] Dynegy at 35.

[207] EPSA Reply Comments at 12.

[208] *See* NEMA at 19. *See also* EPSA Reply Comments.

[209] *See, e.g., EEI,* Duke, CP&L and PacifiCorp.

[210] EEI notes that the NOPR mentions the one percent cap on voting interests by market participants in the National Grid Company in England and Wales but observes that there was no obvious justification given at the time the decision was made.

[211] EEI at 26.

[212] CTA at 4.

[213] Alliance Companies at 18.

[214] Most investor-owned utilities agree with EEI. An exception is Cinergy which urges the Commission to incorporate the one-percent ownership standard in the final regulations ''exactly as proposed'' because such a prohibition ''is vital to preserving a RTO's financial independence characteristic.'' Cinergy at 17.

[215] Entergy at 28.

[216] Allegheny Reply Comments at 10.

prohibit affiliated transcos.[217] It argues that the Commission should allow 100-percent ownership of voting equity and ensure non-discriminatory transmission access through codes of conduct and state commission oversight, in the case of a single state RTO. It observes that ''in the natural gas industry there are numerous transcos (pipelines) that are affiliated with gas producers, marketers and/or distribution companies and there is no basis to conclude that this structure would be less likely to succeed in the electric power industry.'' [218]

Other commenters disagree and urge the Commission to adopt even stricter standards on ownership than those presented in the NOPR.[219] For example, APPA recommends that the final rule prohibit any ownership interests in RTOs by market participants.[220] APPA states that even a one-percent ownership would represent an unjustifiable and unnecessary exception to the independence standard. South Carolina Authority agrees with APPA and argues that the NOPR failed to present a ''public policy benefit'' for allowing even a *de minimis* ownership interest.[221] NASUCA also shares this view. In addition, it asserts that as soon as the Commission allows any ownership by market participants it will be forced to continually track the share of each market participant, including affiliates. NASUCA argues that this would be ''time-consuming, difficult and expensive'' and would represent the very antithesis of the independent, lightly regulated structure that the Commission wished to foster.

TDU Systems concurs and observes that any ownership by market participants will trigger the ''chasing after conduct'' regulation that the Commission said it hoped to avoid.[222]

In addition, TDU Systems criticizes EEI's ten percent proposal. TDU Systems asserts that EEI fails to understand the rationale for the ''safe harbor'' proposal in the NOPR. TDU Systems argues that the regulatory purpose of a ''safe harbor'' is to ensure that *''no case-by-case review of the regulatory agency is required.''* [223] Therefore, TDU Systems contends that it would be inappropriate to adopt EEI's proposed ten percent because this percentage is not in the ''safe harbor'' but, as recognized by other regulatory agencies, raises a clear risk of control. Consumer Groups supports this view and points to one case in which a court decided that a three-percent ownership interest of a company's common stock was found to be ''sufficient to assert control over the corporation because the ownership of the other common shares was widely dispersed.'' [224]

The Alliance Companies, who support a ceiling of five percent ownership in voting interests by market participants, state that they ''are aware of no practical means of tracking who has an ownership interest at a threshold of less than five percent '' because SEC regulations require reporting of ownership in publicly traded companies only at five-percent ownership and above. In contrast, Cinergy asserts that enforcing a lower ownership limit should not be a problem. It states that the Commission could keep track of ownership interests ''through transmission owners'' representations and subsequent audits if the need arises.'' [225]

APPA, which argues for absolute and total prohibition on voting ownership by market participants, asserts that even with access to SEC data it will be difficult for the Commission to keep track of who really owns voting shares since they are often registered in ''street'' names. Therefore, it urges the Commission to impose a total prohibition on ownership by market participants. South Carolina Authority agrees and further argues that anything less would fail to achieve the Commission's characterization of an RTO as entity in which ''the control of transmission operation is *cleanly separated* from power market participants.'' [226] It concludes that ''[t]here is nothing 'clean' about permitting incumbent transmission owners to indefinitely maintain an ownership interest, voting or otherwise, in the newly created RTO.'' [227]

EPSA suggests a compromise that would allow greater flexibility with respect to initial ownership interests. It proposes that the Commission establish time limits on voting ownership. TDU Systems makes a similar recommendation with respect to passive ownership. While TDU Systems states that it would prefer an absolute prohibition on market participants owning voting shares, it suggests that the Commission might consider allowing transmission owners to ''hold passive, non-voting ownership interests in excess of one percent as an extraordinary transition measure.'' [228] However, TDU Systems recommends that such interests be reduced to one percent or below in a ''relatively short period of time.''

b. By Classes of Market Participants. SRP asserts that the NOPR is flawed because it is not sufficient to place a limitation on the ownership interests that can be held by a single participant and its affiliates while ignoring the possibility that other owners may have similar interests. SRP urges the Commission to recognize that ''[a]n interest that may be considered *de minimis,* when viewed in isolation, could still result in effective control when aggregated for a group with common interests.'' [229] Therefore, it recommends that limits be placed not only on the ownership interests of an individual market participant but also on the ownership interests by other market participants with similar economic interests. SRP does not recommend a specific percentage for a group cap, but Industrial Consumers urge the Commission to cap the voting interests of any group at five percent.

FP&L contends that there is no need for ownership caps for a group of market participants because they will often have conflicting economic interests. It gives the example of a group of transmission owners with ownership interests in an RTO who also own affiliated power marketers. FP&L argues these marketing affiliates will compete against each other and this rivalry will mitigate the potential for collusion among the parent companies that jointly own the RTO. Alliance Companies agree with this view. They assert that ''[i]n today's competitive power markets, all market participants, including those traditionally classified within the same

[217] In contrast, APPA states that affiliated transcos should be allowed ''only where such private companies operate under the direct, ongoing supervision of a strong, fully functional regional Independent System Operator.'' APPA at 28.

[218] FP&L at 26.

[219] *See, e.g.,* Midwest Municipals, APPA, TDU Systems and Industrial Consumers.

[220] APPA clarifies that it does not oppose market participants owning ''for-profit'' transcos if the transcos come under the supervision of strong fully functional ISOs. Industrial Consumers recommend that a one-percent cap should be adopted in the final rule as a general requirement rather than as a possible safe harbor. In addition, it recommends that the cap be calculated on a corporate-wide basis to avoid the situation of multiple affiliates each with a one-percent interest. *See* Industrial Consumers at 30.

[221] *See* South Carolina Authority at 18.

[222] TDU Systems at 41 *citing* FERC Stats. and Regs. ¶ 32,541 at 31,145.

[223] TDU Systems Reply Comments at 14 (italicized in the original).

[224] Consumer Groups Reply Comments at 8.

[225] Cinergy at 18.

[226] South Carolina Authority at 8 (quoting from FERC Stats. & Regs. ¶ 32,541 at 33,718 (emphasis added by the quoter)).

[227] South Carolina Authority at 14.

[228] TDU Systems at 42.

[229] Salt River at 11. United Illuminating agrees and states that if the Commission ''were to adopt a higher *de minimis* standard, such as five or ten percent ownership interest, it would be relatively easy for five or six market participants owning such percentages to control the operations of an RTO.'' United Illuminating at 39–40.

stakeholder group are likely to be competitors'' and, therefore, that it is unlikely that there will be a ''nexus of interest.'' [230]

EEI argues that ownership caps on groups of market participants would be ''impractical and extremely burdensome on Commission resources'' because the Commission would have to keep track of ownership levels by every market participant and also align market participants into specific groups with ''alleged common interests.'' [231] In addition, it contends that this task would be difficult to do because markets are evolving and the business objectives of individual firms will change as they buy or sell assets. Moreover, while accepting that ''some market participants may have common interests at certain times'' EEI believes that such ''coalitions'' would be ''fragile, short-lived and unlikely to result in a serious threat to the independence of the RTO.'' [232]

A number of commenters assert that a cap on voting interests will thwart capital formation in new and existing transmission facilities. For example, UtiliCorp contends that such a cap ''may potentially choke off significant sources of capital'' for the formation of for-profit transcos.[233] Various commenters from the financial community argue that such a cap would make it difficult to create RTOs that function as for-profit transcos. Salomon Smith Barney states that current owners of transmission assets need to retain a larger ownership interest, at least for a transition period, in order to avoid heavy capital gains taxes. It estimates that many current transmission owners would have to pay capital gains taxes on about 35 to 50 percent of the current book value of their transmission assets if they were to sell these assets.

Alliance Companies asserts that restrictions on ownership would reduce the potential pool of investors (*i.e.*, buyers of transmission assets) and therefore reduce the price that current owners could receive for their assets. They contend that this would be especially damaging because it would place limits on ownership by ''those entities that are most likely to understand the potential value of the business model.'' [234] Alliance Companies states that the Commission should allow five-percent individual ownership interests by industry participants because this will provide confidence to other, non-energy industry investors that the transco will be a financial success.[235] In general, the Alliance Companies and other commenters that share this view take the position that a one-percent cap for market participants will be a major impediment to the creation of for-profit transcos and that the *de facto* effect of such a cap will be to limit the industry to the ISO model.

Passive (Non-Voting) Ownership Interests in the RTO. A number of privately-owned utilities stress that the final rule must distinguish between passive and voting interests in RTOs.[236] For example, while EEI is willing to accept a ten-percent cap on ownership of voting interests by individual market participants, it states that ''[t]here should be no limit on the amount of passive ownership interest'' because ''[p]assive owners who lack voting rights have no ability to control the firm.'' [237] Enron/APX/Coral Power also support this position. They urge the Commission to ''explicitly and unambiguously allow incumbent utilities and other power industry participants to possess passive but not controlling ownership interests in an RTO.'' [238] Southern Company states that ''[p]assive ownership of transmission facilities—even up to 100 percent—should not be a concern.'' [239] United Illuminating, while recommending that the Commission allow passive ownership, recommends that we should not issue generic rules because passive ownership is a ''complex matter that must be reviewed on a case-by-case basis.'' [240]

EEI contends that some of the opposition to passive ownership by market participants may simply reflect a misunderstanding of the fiduciary responsibilities that the board of a for-profit transco has to its passive owners. EEI asserts that, under Delaware law and various model statutes, the fiduciary responsibilities of a for-profit transco board, its managers and owners that hold voting rights to a passive owner are limited to maximizing the value of the transmission assets and ''not the value of any other assets that may be held by the passive owner.'' [241] According to EEI, a transco board has no fiduciary obligation to take actions to produce economic benefits for other assets such as generating units that happen to be owned by its passive owners. Entergy states that if there are any lingering doubts about the fiduciary obligation of the board and its voting members, a provision could be inserted in the ''transco's limited liability agreement that specifically directed that managers would have no fiduciary duty to consider the private interests of members'' and that such a provision would be enforceable under Delaware law.[242]

Consumer Groups, however, questions the legal feasibility of this approach. It cites to several law review articles which it argues raise doubts as to whether fiduciary duties assigned by a state law to the directors of a subsidiary corporation can be removed by private agreement. It also cautions the Commission not to get lost in ''a lawyer's duel over conflicting citations about the treatment of passive and affiliated ownership interests'' when the fundamental issue is the need to safeguard independence and ''avoid any appearance of partiality.'' [243]

EEI points to our recent decision in *Entergy Services, Inc.*, as demonstrating that the Commission recognizes that passive ownership is not inconsistent with the independence principle under the ISO principles of Order No. 888.[244] It asks that the Commission reach the same policy conclusion for any similar independence requirement in the final RTO rule. In contrast, the South Carolina Authority observes that while the Entergy decision could be read to imply that the Commission has ''prejudged this issue,'' the Commission should now use the opportunity of this NOPR to take another look at the issue.[245]

EEI also points to actions or policies taken by other federal regulatory agencies that it argues support its contention that passive ownership does not necessarily convey control. It observes that the definitions of ''holding company,'' ''affiliate'' and ''subsidiary company'' in PUHCA are all tied to ownership of voting rather than non-voting shares. Similarly, EEI states that the FCC ''attribution rules'' used to determine when broadcasters and cable companies own or control another

[230] Alliance Companies at 21–22.

[231] EEI Reply Comments at 21.

[232] *Id.*

[233] UtiliCorp at 7.

[234] Alliance Companies at 19.

[235] In contrast, APPA asserts that ''if the underlying business model is sound, investors will come.'' APPA at 36.

[236] *See, e.g.*, EEI, Enron/APX/Coral Power and UtiliCorp.

[237] EEI at 26. EEI relies on a legal memorandum that concludes that passive ownership interests are ''necessarily permissible, no matter how large and no matter what other interests they are combined with.'' EEI Appendix H at 17.

[238] Enron/APX/Coral Power at 14.

[239] Southern Company at 42.

[240] United Illuminating at 7.

[241] EEI at 26.

[242] Entergy at 29.

[243] Consumer Groups Reply Comments at 9.

[244] EEI at 26 *citing Entergy Services, Inc.*, 88 FERC ¶ 61,149 (1999).

[245] South Carolina Authority at 22.

broadcaster or cable company are keyed to voting rather than passive ownership interests. According to EEI, these policies demonstrate that other federal regulatory agencies do not believe that passive ownership conveys control and that the Commission should adopt a similar policy.

EEI also contends that the Commission has already allowed a ''passive economic interest'' in all of the ISOs that have been approved to date. Sierra Pacific makes a similar argument. Sierra Pacific contends that ''profits'' made by an ISO go back to the transmission owners even though they may have relinquished operational and decisionmaking control. It argues that ''this arrangement [in ISOs] is the essence of a passive ownership interest.'' [246] The principal difference is that ''the passive ownership interest in a Transco involves ownership in the transco itself rather than the assets operated by the Transco.'' [247] However, it argues that in substance both types of interests are the same since they allow the owner to share in the profits derived from operating their transmission facilities without having any influence over that operation. Sierra Pacific concludes by urging the Commission to allow passive ownership in both types of institutions to avoid creating ''an artificial incentive in favor of ISOs instead of Transcos.'' [248]

Enron/APX/Coral Power point to the example of National Grid Company (NGC) in England and Wales as a real world example of passive ownership of a for-profit transco by market participants. For several years after privatization in 1990, the regional electricity companies (RECs) were allowed to own NGC but were ''expressly barred from participating in day-to-day management or interfering with the ability of NGC to fulfill the purpose of privatization.'' [249] However, in reply comments TDU Systems contends that Enron/APX/Coral Power fails to mention that this passive ownership arrangement was terminated after several years. Citing to a recent interview with Callum McCarthy, Great Britain's Director of Gas and Electricity Supply, TDU Systems points out that the RECs were ''told to divest these interests, and did so.'' [250]

In contrast, TDU Systems and others ask the Commission not to allow passive ownership in the final rule.[251] TDU Systems say that ''the line between passive and active ownership is often not a bright line.'' [252] As an example, it states that in the recent Alliance transco filing, the divesting transmission owners ''hold supposedly passive ownership interests in the Transco, but retain the right to pass on a number of different business transactions.'' [253] TDU Systems assert that if the Commission opens the door to ownership of RTOs by market participants, it will be forced to engage in substantial ''conduct policing.'' Salomon Smith Barney concurs and states that passive ownership ''will prove troublesome for both the utilities and FERC'' because it creates a ''need to constantly police supposedly passive ownership positions to make sure that they remain passive in all respects.'' [254]

South Carolina Authority echoes this point. It argues that by allowing passive ownership the Commission would be put in the difficult job of determining ''how 'passive' a particular 'passive interest' really is.'' [255] It urges the Commission not to compromise its ''bedrock position on independence'' because it will lead to ''an endless series of extensive battles over ownership structure, corporate bylaws and rules, layered on top of continuing allegations of discrimination in the marketplace.'' [256] It asks ''why * * * risk compromising the independence principle?'' [257]

Just as several commenters raise capital formation arguments in support of the need to allow some voting interests by market participants, many of these commenters also raise similar arguments in support of allowing passive ownership.[258] In general, they contend that current owners are not likely to sell transmission assets voluntarily to others if selling leads to a large capital gains tax payment. They contend that passive ownership provides a creative way to allow transfer of grid operations to an independent party while reducing the tax burden on current transmission owners.

In contrast, Consumer Groups asserts that there are mechanisms other than passive ownership that would ''permit 'divestiture' without tax consequences'' and that an important advantage of these other mechanisms is that they would ''better assure independence.'' [259] As one example, Consumer Groups asserts that a vertically integrated utility could spin off its transmission assets to its shareholders. While recognizing that the IRS Code seems to eliminate the favorable tax treatment if the spun-off corporation is sold within two years of the original distribution, Consumer Groups states that this is a rebuttable, not an absolute, prohibition and that a recent IRS proposed rule seems to suggest that favorable tax treatment could be retained if the spin-off of transmission assets is done in response to regulatory mandates. South Carolina Authority raises a different argument against regulatory policies to accommodate passive ownership. It asks why the Commission should feel obligated to minimize the federal corporate income tax responsibilities of privately owned utilities.

Several commenters recommend that we accept passive ownership at least as a necessary transition device. For example, Enron/APX/Coral Power state that ''there will likely need to be some years of passive ownership by industry participants before the RTOs will have demonstrated their viability as stand-alone transmission businesses that can successfully be taken public.'' [260] ISO–NE, which favors a single grid company for all of New England, observes that because of ''tax and other considerations, current owners of transmission assets may wish to avoid immediate divestiture, and may wish to retain indirect ownership.'' [261] Salomon Smith Barney predicts that most utilities will want to dispose of passive and minority interests over time. NECPUC, representing the six New England commissions, echoes this point. It states that the Commission may have to accept ''[t]ransitional periods in which the ownership interests of market participants are phased out over time.'' If such transitions are allowed, NECPUC urges us to ensure that they are ''carefully monitored.'' [262] TDU Systems, as noted earlier, recommends that passive ownership should be used only as an ''extraordinary transition measure'' and should be allowed only for a short period of time.

RTO Governing Boards. Many commenters recommend that membership on RTO governing (*i.e.,* decisional) boards be limited to non-stakeholders.[263] For example, the Justice

[246] Sierra Pacific at 11.

[247] *Id.*

[248] Sierra Pacific at 12.

[249] Enron/APX/Coral Power at 14.

[250] TDU Systems Reply Comments at 22.

[251] *See, e.g.,* APPA, Industrial Consumers and South Carolina Authority.

[252] TDU Systems at 41.

[253] Entergy at 42.

[254] Salomon Smith Barney Reply Comments at 15.

[255] South Carolina Authority at 21.

[256] *Id.* at 24.

[257] *Id.*

[258] *See, e.g.,* Entergy and Southern Company.

[259] Consumer Groups Reply Comments at 11.

[260] Enron/APX/Coral Power at 14.

[261] ISO–NE at 20.

[262] NECPUC at 11.

[263] *See, e.g.,* Advisory Committee ISO–NE, APX, Avista, Desert STAR, Industrial Consumers, PJM,

Continued

Department urges the Commission to consider barring all market participants from any decision-making role. It says that this approach assures ''a clean structural break.'' [264] If stakeholders are allowed on the governing board, the Justice Department recommends that independents (*i.e.,* non-stakeholders) should constitute a majority of the board's voting members and that the board's voting rules not allow vetoes by any one class of stakeholders. Most commenters who support an independent board recommend that the maximum size of the board not be specified in the final rule but instead be left to the discretion of the participants. Two exceptions are the South Carolina Authority, which recommends that board size be limited to seven to nine directors, and the Midwest Municipals, which suggests that the Commission question any non-stakeholder board that has more than 10 to 15 members.

Other commenters state that a danger of non-stakeholder boards, such as those already approved by the Commission for several ISOs, is that they become isolated and sometimes unresponsive to stakeholder concerns. UtiliCorp, for example, asserts that ''one of the most frequently heard criticisms of the ISOs currently in existence is their unresponsiveness and lack of accountability.'' [265] Several other commenters echo this concern and recommend that an independent board be required to consult formally and informally with advisory committees of stakeholders (*i.e.,* a two-tier form of governance). For example, the Midwest Municipals recommend that RTOs with non-stakeholder boards ''be required to have a senior management or advisory committee made up of market participants from each relevant market sector and subordinate, issue oriented committees'' similar to those that exist in the PJM, New York and New England ISOs.[266] STDUG recommends that if a non-stakeholder board is formed ''it must be accompanied by some action forming mechanism that forces the board to listen and consider the concerns of all members or stakeholders in the RTO.'' [267]

EPSA urges the Commission to pay close attention to the composition and functions of any committee structure that operates underneath a governing board because independent governance ''does not stop at the ISO board.'' [268] It contends that this is necessary for independence because advisory committees of stakeholders will often have *de facto* decisionmaking power. Dynegy makes specific recommendations for any stakeholder committees that operate below and report to an RTO board. It recommends that such committees be governed by ''segment voting''—each industry segment would have a proportional vote; each market participant would have to choose to participate in one market segment; and the votes within a segment would be split among however many entities choose to participate in that segment. It observes that this approach has been adopted or proposed in the PJM, NEPOOL and New York ISOs.

Other commenters urge us not to prohibit stakeholder or hybrid boards consisting of stakeholders and non-stakeholders such as the one that exists in California. Cal ISO, noting that it is the only FERC-jurisdictional ISO with a stakeholder board, states that ''[t]he Cal-ISO stakeholder board has worked'' and urges us to confirm the acceptability of a stakeholder board in the final rule if the board is structured to ensure that no market participant or class of market participants can control the decisions of the RTO.[269] Dairyland points out that the Commission has encouraged and approved stakeholder boards under the independence principle for ISOs in Order No. 888.[270] Dynegy recommends a hybrid governing board with ''disinterested'' (*i.e.,* non-stakeholder) members comprising one-third of the board and stakeholder members comprising the remaining two-thirds.[271] However, it observes that mandated stakeholder representation would be ''inappropriate'' for an RTO that is a for-profit transco. California Board urges us to allow a variety of governance forms including stakeholder boards ''until and unless experience shows that one form'' is clearly superior to other forms of governance.[272] TXU Electric states that ''stakeholder representation is a legitimate form of governance for a regional transmission organization'' and, in fact, is the required form of governance under the recently enacted Texas electric restructuring statute.[273]

Role of State Agencies. Commenters express a wide range of opinions on the appropriate role of state agencies. The comments fall generally into two categories: the role of state agencies during the developmental stage and the role of state agencies after an RTO begins operating.

Many commenters believe that state commissions and other state agencies should have a major role in RTO development. NARUC argues that state commissions ''should fully participate in RTO formation and development.'' [274] State commissions generally take the position that their involvement is important because the size, scope and functions of an RTO will be critical for the success of their state-by-state retail choice programs.[275] NECPUC notes that it had an important role in shaping the design of the ISO-NE before any formal filing was made at the Commission. Nine Commissions, representing state commissions from the East-Central, Midwest and Southwest regions, gives a specific example of how the Commission should defer to state commissions. They state that if a critical mass of state commissions in their region reach agreement on the appropriate boundaries for an RTO, then FERC ''should provide deference to that collective state determination.'' [276]

Other commenters outside of the state regulatory community also address the issue of the appropriate role for state commissions. For example, Enron/APX/Coral Power say that state regulators and politicians should play a role in encouraging local transmission owners to join RTOs but ''[t]he role of states * * * should extend no further.'' [277]

Once an RTO becomes operational, Enron/APX/Coral Power argue that state commissions should have no special

Reliant, South Carolina Authority and UtiliCorp. In general, these commenters adopt the convention used in the NOPR that a non-stakeholder is synonymous with a non-market participant. *See* note 187 in FERC Stats. and Regs. ¶ 32,541 at 33,726.

[264] Justice Department at 4. The Southern Company states that if the Commission requires non-stakeholders boards RTOs that are ISOs, then it must allow transmission owners the right to establish ''performance standards'' for the RTO and the right to withdraw if the RTO fails to meet these standards. Southern Company at 40–41.

[265] UtiliCorp at 11.

[266] Midwest Municipals at 19.

[267] STDUG at 7–8.

[268] EPSA at 15.

[269] Cal ISO at 15. Cal ISO points out that this has been achieved through a board of governors in which (1) no one voting class is able to block or veto an action, and (2) no two classes together are able to form a sufficient majority to make decisions, and (3) no entity (including its affiliates and subsidiaries) is able to participate in more than one voting class. *See* Attachment A–1 of Cal ISO.

[270] ''A governance structure that includes fair representation of all types of users would help to ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner.'' Order 888, FERC Stats. and Regs. ¶ 31,036 at 31,730–731

[271] Dynegy recommends that five ''segments'' for the stakeholder representatives: transmission owners, transmission-dependent utilities, marketers, end-users and independent power producers. Dynegy at 42.

[272] California Board at 6.

[273] TXU Electric at 9.

[274] NARUC at 11.

[275] *See, e.g.,* Illinois Commission.

[276] Nine Commissions at 6.

[277] Enron/APX/Coral Power at A–3.

role and, in fact, the RTO ''should be protected from local interference.'' Their argument for minimizing the role of state agencies is that ''no other commercial activity (with the possible exception of telecommunications) is more intrinsically in interstate commerce.'' Conlon, the former President of the California Public Utilities Commission, expresses a similar view (''local control, although desirable from a states' rights standpoint, should be sacrificed to get interstate control of the entire interconnection.'') [278]

On the issue of voting rights for state commissions, Enron/APX/Coral Power argues that it would be inappropriate for any state commission to be a voting member of an RTO. Their rationale is that the state commission would lose its ability to monitor the relationship between the RTO and any entity that may be serving the state's domestic load if it is also a voting member of the RTO board. NECPUC expresses a similar view. While recommending that state commissions have extensive communication with the RTO and its participants, it concludes that state commissions ''should not have a vote in the governance of the ISO New England.'' [279] Arizona Commission says that states should have the right of ex officio membership but that ''FERC should not force the states to be voting members.'' [280] ISO-NE also shares this view. It contends that it would be ''awkward'' for a state official to serve as a voting director of an RTO for several reasons. First, it could create a conflict between the state official's duties as an RTO board member and his or her regulatory or administrative duties at the state level. ISO–NE argues that many state conflict of interest laws may expressly prohibit such service because of the conflicts it would create.[281] Second, in the case of a multistate RTO, it may difficult for an official from one state to vote for decisions that are good for the residents of all the states served by the RTO. Third, the solution of having a board member from each state ''could create gridlock or unwieldy boards.'' [282]

Florida Commission makes a distinction between for-profit and non-profit RTOs. It says that it would be inappropriate for members of a state regulatory body or other state officials to serve on the board of a for-profit transco. However, Florida Commission believes that it may be appropriate for a state commissioner to serve on the board of a non-profit RTO if disputes involving the RTO and other parties do not come before the state commission.

Washington Commission expresses a different view. In its opinion, the role of state commissions should vary depending on the type of board. It recommends that state involvement could be limited to the selection of the non-affiliated board members for a non-stakeholder or hybrid board. In contrast, if there is a stakeholder board, Washington Commission urges that states be granted ''voting member status.'' In the case of a for-profit transco, it urges the Commission to require a formal advisory role for the states.

Section 205 Filing Rights. Many IOUs and public systems oppose the NOPR's proposal to require that RTOs have ''exclusive and independent authority to file changes to its transmission tariff with the Commission under section 205 of the Federal Power Act.'' [283] In contrast, those who support the proposal assert that it is a necessary and logical implication of the Commission's previously stated policy that the ''[a]uthority to act unilaterally * * * is a crucial element of a truly independent ISO.'' [284] SRP recommends that ''the need for an RTO to independently administer its own tariff must be balanced against the need for individual transmission owners to maintain control over their ability to recover their revenue requirements and meet their debt service obligations.'' [285]

Those who oppose the proposal focus on the case of an RTO that is an ISO. Transmission ISO Participants argues that the proposal is bad law and bad policy. Citing the Supreme Court decision in *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*,[286] it asserts that the Commission does not have the legal authority to grant section 205 filing rights to an ISO. It contends that the FPA grants this fundamental right to transmission owners that are public utilities. While a transmission owner may ''voluntarily cede'' this right to an ISO, the Commission cannot compel a transmission owner, either directly or indirectly, to give up this legal right. Puget Sound argues that the proposal would have the effect of reducing the transmission-owning utility to little more than a ''bystander'' and could constitute an illegal ''taking'' under the Fifth Amendment of the U.S. Constitution.

Transmission ISO Participants also claims that the Commission's previous decisions in this area have not been consistent. It asserts that the Commission ''required transmission owners to cede their section 205 rights to the ISO in our order approving the PJM ISO.'' [287] But it points to the fact in a 1997 California ISO order that the Commission seemed to establish a much smaller role for the ISO (''the ISO is responsible for only collecting the revenue requirement.'') [288] Furthermore, it notes that in this same order the Commission decided to set all rate design and rate methodology issues in the dockets established for the filings made by the transmission owners, and not in a docket for the transmission tariff filing made by the ISO.[289]

Many commenters also address whether it would be practical to give RTOs FPA section 205 filing rights for transmission rate design and terms and conditions that directly affect access while transmission owners would retain section 205 rights for overall revenue requirements. A number of commenters say that this distinction is unworkable because the two are inextricably connected (*i.e.*, changes in rate design can have major impacts on revenue collections).[290]

However, other commenters argue that the Commission cannot realistically expect an RTO to be a neutral and unbiased transmission provider unless the RTO has full legal authority to propose changes in its own transmission tariff.[291] PJM states that ''its ability to function would be severely hindered'' unless it has the ability to unilaterally make tariff filings. It points to several recent instances of emergency filings with us as examples of why it must have its own independent filing authority without getting the prior approval of

[278] Conlon states that these are his views and are not necessarily the views of any present or former Commissioners or staff of the California PUC.

[279] NECPUC at 9.

[280] Arizona Commission at 5.

[281] In contrast, Reliant recommends that ''state officials should serve as board members in order to avoid conflicts in future decisions.'' It appears that Reliant is referring to future decisions of the state agencies. Reliant at 5.

[282] ISO–NE at 3.

[283] *See, e.g.,* AEP, Alliance Companies, CMUA, Duke, Florida Power Corp., LPPC, Metropolitan, Midwest Municipals, Montana-Dakota and Southern Company.

[284] *Citing* NEPOOL, 79 FERC ¶ 61,974 at 62,585 (1997). *See, e.g.,* PJM, Cal ISO, Industrial Consumers, Montana Commission, NECPUC and NASUCA.

[285] SRP Reply Comments at 12.

[286] 350 U.S. 332 (1956).

[287] Transmission ISO Participants at 20.

[288] *Quoting* 81 FERC ¶ 61,122 at 61,506 (1997).

[289] However, the California ISO asserts that it has ''exclusive and independent'' authority ''to modify the design of rates for transmission and ancillary services.'' *See* Cal ISO at 18.

[290] *See, e.g.,* EEI, Transmission ISO Participants and Southern Company.

[291] *See, e.g.,* Cal ISO, PJM ISO, Industrial Customers, Montana Commission, NECPUC and NASUCA.

transmission owners or any other group. It argues that it will not be able to satisfy its responsibility to ''provide for safe and reliable operation of the transmission grid and operation of a robust, competitive, and non-discriminatory electricity market'' without such authority.[292] However, PJM does state that transmission owners, rather than the RTO, should have the unilateral right to seek changes in the RTO's tariff to address changes in the transmission owners revenue requirements with respect to transmission facilities.[293]

Oneok, a power marketer, states that an RTO needs its own section 205 filing authority because it would not be able to reach a consensus and act quickly if it must get the prior approval of all stakeholders. However, Oneok suggests an alternative to what was proposed in the NOPR. It recommends a two-tier approach to transmission tariff filings. Under this proposal, ''transmission-owning utilities would be free to file changes to their rates (or rate structures) at any time'' to their single customer, the RTO.[294] The RTO would then be free to ''repackage'' the transmission capacity and services that it purchased under these separate transmission owner tariffs in its own RTO transmission tariff filed under section 205. Oneok states that there are precedents for this approach in prior Commission practices.

Commission Conclusion. The Basic Independence Principle. In the NOPR, we repeated our earlier statement that ''the principle of independence is the bedrock upon which the ISO must be built ''and emphasized that this principle must apply to all RTOs, whether they are ISOs, transcos or variants of the two. We also stated that ''[a]n RTO needs to be independent in both reality and perception.'' We reaffirm both principles in the Final Rule.

In applying these principles in the context of ISOs, we have stressed the importance of a decisionmaking process that is independent of control by any market participant or class of participants. This, in turn, required that we pay considerable attention to governance (*e.g.,* voting shares and voting rules). Because ISOs are typically non-profit and non-share corporations, we generally did not have to consider the effect of ownership interests on the independence of the ISO. This will change with the emergence of for-profit RTOs, such as transcos, that have ownership interests. For these types of RTOs, we will have to examine how ownership of the RTO by market participants could affect the independence of its decisionmaking process.

Who Is a Market Participant? The overall purpose of the independence standard in the Final Rule is to ensure that an RTO will provide transmission service and operate the grid in a non-discriminatory manner. Equal access requires RTOs to be independent. Implementation of this standard then requires answering the question: independence from whom? Our logic in the NOPR, which we have adopted in the Final Rule, is to define a group of entities, referred to as market participants, whose economic or commercial interests are likely to be affected by an RTO's decisions and actions.

Commenters provided many helpful comments on the definition of market participant that was proposed in the NOPR. As noted in the summary, the commenters generally fall into two broad categories: those who argue that the NOPR definition is too broad and those that argue that it is too narrow. We find that these views were not always inconsistent since the commenters were often discussing different aspects of the definition. After a careful review of the comments, we conclude that it is necessary to change the definition of a market participant that was proposed in the NOPR. The revised definition at section 35.34(b) is:

(2) *Market participant* means:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides transmission or ancillary services to the Regional Transmission Organization, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions.

(3) *Affiliate* means the definition given in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11)).

Before discussing how this definition is different from the NOPR definition, it is useful to consider why a definition of market participant is needed in the first place. It is the Commission's view that an RTO must be independent of any entity whose economic or commercial interests could be significantly affected by the RTO's actions or decisions. Without such independence, it will be difficult for an RTO to act in a non-discriminatory manner. Therefore, the definition focuses on those entities whose economic and commercial interests can be significantly affected by the RTO's behavior. However, it should be emphasized that the definition of a market participant is simply a starting point for implementing the independence standard. The definition is used as a reference point for establishing limits on ownership (*i.e.,* an RTO's ownership of market participants and market participants' ownership of an RTO) and standards for independent decisionmaking or governance. As discussed below, the fact that a particular participant is defined as a market participant does not preclude it from having any active or passive ownership interest in an RTO.

We agree with many commenters that the NOPR definition was too broad in defining a market participant to be ''any entity that buys or sells electric energy in the RTO's region or in any neighboring region that might also be affected by the RTO's actions.'' As several commenters pointed out, a literal reading of this definition would make market participants of every residential, commercial, industrial and wholesale electric customer in the RTO region and some neighboring regions. This is clearly too encompassing and was not our intent. We therefore are narrowing the definition of a market participant in the Final Rule to include those who sell or broker electric energy but not those who buy electric energy.

We recognize, however, that there may be circumstances where buyers of electric energy could buy a controlling interest in a for-profit RTO and manipulate its access and curtailment decisions to their advantage. Such an outcome would clearly be inconsistent with the independence standard. Therefore, as a backstop, we are adding paragraph (b) to the definition (''any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the RTO's actions or decisions''). The addition of this paragraph allows us, on a case-by-case basis, to consider whether particular buyers of electric energy (or any other entity) could manipulate an RTO's decisions to the disadvantage of other RTO customers.

We are also dropping the phrase ''in the RTO's region or in any neighboring region that might also be affected by the RTO's actions.'' Given the high degree of integration within the Eastern and Western Interconnections, the growth of transactions involving buyers and sellers separated by hundreds of miles and the participation of energy concerns

[292] PJM at 53.

[293] PJM at 54. The California, New York and New England ISOs agree with PJM on this point.

[294] Oneok at 8.

in multiple markets, we conclude that it would be virtually impossible to apply a geographically delineated standard. However, we will consider requests for waivers from entities in other Interconnections who can demonstrate that their economic or commercial interests would not be significantly affected by the RTO's actions or decisions.

We are also making one other change to the NOPR definition to expand its scope. Paragraph (a) expands the NOPR definition by including entities that provide transmission or ancillary services to an RTO. We believe that it would compromise an RTO's independence if one or more transmission owners could influence the RTO's decisions to the detriment of other market participants. Therefore, it is appropriate to include providers of transmission service as market participants.[295] With regard to the creation of RTOs that are transcos, we have developed policies on the level of ownership that market participants may possess, as discussed below, in order to ensure that the operating decisions of the RTO are truly independent and non-discriminatory.

We believe that it is necessary to include ancillary service providers as market participants since the RTO is the supplier of last resort for ancillary services. As a consequence, the RTO is likely to have considerable discretion in defining the types and quantities of ancillary services needed and how they will be procured (*e.g.,* market design). An RTO's decisions in any of these dimensions can have major economic effect on one or more providers of such services. Therefore, we define these entities as market participants to ensure that they are not in a position to influence the RTO's decisions to their own advantage.

Several other commenters urged us to include distribution entities as market participants. At present, most distribution entities provide a bundled service. The bundled service includes the sale of electric energy as well as the delivery of this electric energy over local distribution facilities. Since these traditional distribution entities are selling electric energy, they would be considered market participants under the definition.

However, several commenters pointed out that a new type of distribution entity is likely to emerge with the spread of retail competition. This type of distribution entity would simply transmit electric energy over distribution facilities for others and would not sell electricity.

The issue is whether this type of pure distribution entity should be considered a market participant. Several commenters pointed to the danger of allowing one or two distribution entities to control an RTO. Their concern is that these distribution entities could use their control over the RTO to favor their distribution facilities over the facilities of non-affiliated distribution entities when the RTO has to choose among competing requests for transmission service or alternative curtailment actions. Other commenters minimize this risk and argue that distribution entities should be allowed to own RTOs because there are economies in having a single entity provide total delivery service (*i.e.,* transmit electric energy at high and low voltages). The Commission does not wish to create impediments to the efficient integration of transmission and distribution facilities. Therefore, we will not include pure distribution entities in paragraph (a) of the market participant definition. However, if we are presented with evidence that a distribution entity is able to influence an RTO's actions or decisions to the disadvantage of other users, we may find such a distribution entity to be a market participant under paragraph (b) of the definition. Paragraph (a) of the revised definition defines all sellers of electric energy, whether retail or wholesale, as market participants. Several commenters urge us to exclude retail providers of last resort from the definition. These are entities that are required by state commissions or state law to be backup suppliers to retail customers who choose not to switch suppliers in a state-mandated retail competition program. We have decided to include such entities in the market participant definition because they are sellers of electric energy. However, the obligations and responsibilities of such entities are still being developed on a state-by-state basis. As a consequence, even though such entities may be generically referred to as ''suppliers of last resort,'' their responsibilities and incentives may vary widely. The Commission believes that certain factors, (*e.g.,* an entity's sole electric sales are made to satisfy a state requirement and it does not compete for retail load) would support a finding that the entity is not a market participant.

NEPCO *et al.* point to the problem of incumbent utilities that have tried to divest themselves of generating assets but have not yet succeeded. They say that this is likely to be a particular problem for utilities that own minority interests in nuclear plants since it is currently difficult to sell such interests. NEPCO *et al.* request that they not be automatically deemed a market participant because of these ownership interests. Once again, we will entertain requests for exemption. For example, we would be willing to give an exemption if the current owner could clearly demonstrate that it has transferred to non-affiliated entities both the marketing rights and any profits resulting from the sale of electric energy associated with its ownership interest. Any compensation that the market participant receives from the non-affiliated entity should not be tied to profits on specific sales made by this entity.

RTO Economic Interests in Market Participants and Energy Markets. We reaffirm the NOPR proposal that the RTO, its employees and any non-stakeholder directors must not have any financial interests in market participants. As noted in the NOPR, our focus will be on current financial interests. Since this principle raises a number of specific issues, especially with respect to pension rights and benefits, we will continue our current policy of implementing this principle on a case-by-case basis.

Several commenters argued that the NOPR's treatment of financial independence was too narrowly drawn. For example, Dynegy, pointing to the example of ISOs, argues that while ISOs ''may ostensibly be independent of market participants—they are not independent of the market itself.'' [296] The participation of RTOs in the market stems from certain obligations that we require of any RTO: it is the supplier of last resort for required ancillary services and it must attempt to procure such services efficiently in competitive markets. These two requirements mean that most RTOs will be operators of bilateral and spot markets in ancillary services as well as buyers in these same markets. In addition, they will be resellers of any ancillary services that they purchase.

It is our intention that RTOs perform functions that make the transmission infrastructure operate efficiently, not that they take actions in ways that skew competitive outcomes in the market.

[295] It is conceivable that RTO A might provide transmission service to a neighboring RTO B. In such a situation, RTO A would be considered a market participant. RTO A might also acquire ownership interests in RTO B as a first step towards consolidation of the two RTOs. We would anticipate granting a waiver to RTO A from a market participant definition and any associated ownership restrictions if we had reason to believe that the waiver could lead to a larger and more effective RTO.

[296] Dynegy at 35.

Nevertheless we acknowledge that RTO operations may have that effect. Moreover, the two requirements may lead to an outcome that an RTO is not indifferent to whether the prices are high or low. Given this possible conflict, we will require that all RTOs must propose an objective monitoring plan to assess whether the RTOs involvement in these markets favors its own economic interests over those of its customers or members.[297]

Passive Ownership Interests in the RTO. As we have emphasized, the Commission wishes to give industry participants every reasonable opportunity to create RTOs through their own voluntary actions. However, we also recognize that mere exhortations that the industry participants should volunteer to create independent transmission entities will not ensure a truly open and reliable grid in the reasonably foreseeable future. The Commission must take actions to ensure that the stand-alone transmission business is financially attractive and viable. We must also provide a high degree of regulatory certainty and not foreclose viable options for creating and developing RTOs. To provide more certainty, the Final Rule provides guidance on our future policies for establishing revenues, incentives and performance-based regulation for proposed RTOs.[298]

We also recognize that the voluntary creation of RTOs requires that current owners of transmission assets must be willing to transfer operational control of these assets to RTOs or to divest their interests in their entirety. Therefore, it is important that we provide current transmission owners with flexibility in deciding how they will relinquish ownership or control of their transmission facilities to an RTO. Numerous commenters, ranging from IOUs to state commissions to marketers, urge the Commission not to make RTO policy in a vacuum. In particular, they stress that the Commission needs to understand that there are many existing legal and tax disincentives to the outright sale of such assets to an RTO.[299]

Among these potential impediments, commenters identify the federal capital gains tax most frequently. There was agreement among many commenters that it would be unrealistic for the Commission to expect current transmission owners to sell their transmission facilities to an RTO if the sale becomes a taxable event that triggers a large capital gains tax. Therefore, they urge the Commission to accommodate financing and ownership arrangements that facilitate the creation of for-profit RTOs while minimizing the tax burden on current transmission owners who are willing to take actions that would promote the Commission's RTO policies. Many commenters argue that the Commission could significantly accelerate RTO development if we were to allow current transmission owners to retain a passive ownership interest in new RTOs. Several commenters contend that if the Commission fails to accommodate such arrangements, this initiative will be unproductive because our policies would be effectively biased against the creation of for-profit transmission companies that seek RTO status. They assert that such an outcome would be inconsistent with the statement in the NOPR that the Commission wishes to encourage all types of RTOs, whether they are transcos, ISOs or combinations of the two.[300]

In response to these comments, we reaffirm that it is the Commission's policy to encourage all types of RTOs. In light of our evolving experience with the workability of certain RTO models, it would be inappropriate for us to mandate a single RTO model of ownership and operation. While the dominant approach to date has been ISOs, we are receptive to alternative approaches that can provide evidence of the legitimacy of various models of ownership and operation. Because the institutions which we propose to sanction pursuant to this Final Rule will be so influential in operating the Nation's nfrastructure over a period of time, the Commission resolves to implement its independence criteria with an open mind and, to the extent practicable, with flexibility. At this juncture, we therefore propose to remove unnecessary impediments to the creation of transmission companies by allowing market participants to maintain passive ownership interests in RTOs.

We reaffirm our belief that ''[a]n RTO must be independent in both reality and perception.'' [301] This same conclusion was also reached by the DOE Reliability Task Force and the NERC Reliability Panel, two widely respected industry groups comprised of representatives from all sectors of the industry. The DOE Reliability Task Force concluded that regional reliability entities must be ''truly independent of commercial interests so that their reliability actions are—and are seen to be—unbiased and untainted.'' The Electric Reliability Panel concluded that ''[t]o dispel suspicions that the system operator favors one participant over another * * * the operator must be independent of market participants.'' [302]

The Commission concludes that an RTO will not be successful unless all market participants believe that the RTO will operate the grid and provide transmission service to all grid users on a non-discriminatory basis. It is clear that the perception of a broad cross-section of commenters is that passive ownership may interfere with the independent operation of RTOs.[303] In the view of many commenters, passive ownership is only a subtle mechanism to allow existing transmission owners to continue to control use of transmission assets and ultimately deny equal access to competitors. Therefore, we must provide assurances to all market participants that any passive ownership interest is truly passive and will in no way interfere with the independent operation and decisionmaking of the RTO. It is important to require a system of independent compliance auditing to ensure that passive ownership arrangements remain passive over time and to provide assurances to other market participants that the RTO is truly independent.[304]

Those who support the policy of allowing market participants to have passive ownership in RTOs point to the fact that the Commission has accepted many instances of passive ownership in the past. Typically, these arrangements have involved the sale and leaseback of generating units in which a jurisdictional public utility will sell a generating unit to a bank, insurance company or other financial institution. The financial institution will then lease

[297] This is discussed more fully under Market Monitoring. *See infra* section III.E.6.

[298] *See infra* section 111.G.

[299] *See* EEI, Southern Company, United Illuminating, Enron/APX/Coral Power, ISO–NE, NECPUC, Salomon Smith Barney and Konoglie/Ford/Fleishman.

[300] FERC Stats. and Regs. ¶ 32,541 at 33,726.

[301] As discussed below, this overriding consideration is also relevant to active voting interests.

[302] *See* U.S. Department of Energy, *Maintaining Reliability in a Competitive U.S. Electricity Industry: Final Report of the Task Force on Electric System Reliability,* at xv (September 29, 1998); North American Reliability Council, Electric Reliability Panel, *Reliable Power: Renewing the North American Electric Reliability Oversight System* at 17 (Dec. 22, 1997)

[303] *See, e.g.,* Consumer Groups, South Carolina Authority, TDU Systems, Industrial Customers, APPA, Los Angeles, NASUCA, Arkansas Cities and Wolverine Cooperative.

[304] The auditing requirements of this Rule represent one approach to addressing our concern that it may otherwise be difficult to assess the ongoing independence of passive ownership arrangements. We expect that parties will include in any rehearing requests their views on this approach, in general, and the particular auditing requirements that we have adopted.

back the generating unit to the jurisdictional utility. Even though the financial institution is the owner of record, we have generally concluded that it is a passive owner without any real operational control and, therefore, is not a jurisdictional public utility under the FPA.[305]

There are, however, several considerations that distinguish these earlier passive arrangements from the ones that are being contemplated for RTOs. First, the passive ownership arrangements for RTOs (*e.g.,* two-tier LLCs, synthetic leases and leveraged partnerships) may be complicated and multi-layered. Even those commenters who urge that we accept passive ownership as a necessary transition mechanism admit that such arrangements ''will prove troublesome for both utilities and FERC'' because they create the ''need to constantly police supposedly passive ownership positions to make sure that they remain passive in all respects.''[306]

Second, unlike financial institutions, the passive owners will typically own other assets (*e.g.,* generating assets) that could reap major economic benefits if an RTO's decisions can be influenced to their advantage. Therefore, unlike financial institutions, the passive owners in RTOs may have a direct economic incentive to influence the RTO's operating and investment decisions to favor other economic interests.

In response to a request for a declaratory order from *Entergy Services, Inc.,* the Commission found that passive ownership of a transmission entity by a generating entity or other market participant could meet the Commission's ISO standards relating to governance and independence if it were properly designed. Because Entergy's proposal was incomplete, the Commission provided some limited guidance related to: board selection and removal, potential issues about the board's fiduciary duties, attraction of capital and issues about the transmission entity contracting with member companies. In this rule we provide further guidance which we believe will help RTO applicants who may be considering some form of passive ownership structure.

Based on these considerations, the Commission's policy on proposals for passive ownership of RTOs by market participants will have three key elements:

(1) Passive ownership proposals will be reviewed on a case-by-case basis. The Commission will approve a proposal only if we are satisfied that the passive owners have relinquished control over operational, investment and other decisions to ensure that the RTO will treat all users of the grid—passive owners and others—on an equal basis in all matters. The burden of proof is on the RTO to demonstrate that control of the RTO is ''truly independent'' and that the RTO has a decisionmaking process that is independent of control by the passive owners.

(2) The Commission requires any RTO with passive ownership interests approved by the Commission to undertake an obligation and propose processes for an independent compliance audit to ensure the independence of its decisionmaking process from the passive owners. The first independence audit will be required two years after initial approval of the RTO and every three years thereafter. The independence compliance audit must be submitted to the Commission in a public document without any requirement for approval by the RTO board.[307]

(3) The Commission will take appropriate action if it finds evidence of abuses.

We will now discuss implementation of these elements. The first element of our policy is that any RTO that wishes approval for passive ownership above the limits set for active ownership must demonstrate in its application that the passive owners will relinquish effective control over operational and investment decisions. Specifically, the RTO must demonstrate that the proposed arrangement has been designed to ensure that it can treat all users of the grid—passive owners and others—on an equal basis in the provision of non-discriminatory transmission service.

It will be difficult for the Commission to make an assessment of whether a particular passive arrangement achieves true independence in decisionmaking for the RTO board and its management unless an RTO provides complete information about the rights that passive owners have reserved for themselves both as owners of the RTO and as providers of facilities and services to the RTO. In judging any proposal, our overriding concern is that the arrangements provide a high degree of assurance that those who are not passive owners will have equal access to the services provided by the RTO.

To assure ourselves that this standard is satisfied, the Commission will need information on the following issues: fiduciary responsibilities of the RTO board and management to passive owners; ability of the RTO to raise capital independently of its passive owners; ability of the RTO to make investment and financing decisions independently of its passive owners; the extent of control by passive owners over board selection and removal; the extent of control by passive owners over transmission rates, terms and conditions; control of passive owners over issuance of new membership interests and/or equity; services that will be provided by the passive owners or their employees to the RTO; and the extent of access of passive owners to information not available to other market participants.[308] An RTO application seeking approval for passive ownership should provide any other relevant information that will allow the Commission to assess whether passive owners have reserved rights for themselves that are superior to those of other market participants and if such rights constitute control over the RTO.[309]

The second element requires a mechanism for assuring ourselves and market participants that any passive ownership arrangement remains passive over time. The Commission will require the RTO to notify us immediately of any changes in the underlying agreements or facts that occur after the initial filing. The Commission has relied on a similar system of self-monitoring in cases in which we have approved market-based rates. Specifically, we have required that any public utility that receives market-based pricing must notify us of any factual changes that call into question whether it should be allowed to continue to charge market-based rates.[310]

We will also require a system of independent compliance auditing. The auditing must be performed by individuals or organizations that are not

[305] *See* Pacific Power and Light Co., 3 FERC ¶ 61,119 (1978); Baltimore Refuse Energy Systems Co., Wheelabrator Millbury, Inc., 40 FERC ¶ 61,366 (1987).

[306] Salomon Smith Barney Reply Comments at 15.

[307] *See supra* note 304.

[308] For example, this could include information on the market behavior of one or more non-affiliate market participants acquired through a market monitoring program and information on the RTO's proposed investment and operational plans, except where the Commission has approved it as necessary to protect the passive owner's capital investment.

[309] We note that many of these same concerns also apply to RTOs that allow market participants to have ownership interests in voting securities.

[310] When there is a change in the factual circumstances that were the basis for the Commission's approval of market-based pricing, we require that a public utility notify us immediately of this change or at the next update of their market power analysis. This update occurs once every three years. With respect to passive ownership, we will require that the passive owner must notify us immediately of any change in governance in ownership or governance that takes place after our initial approval.

affiliated with the RTO or its owners. The purpose of the auditing would be to ensure that what is passive on paper is passive in reality throughout the transition period. In particular, auditors would assess whether the passive owners have retained rights or privileges in their role as owners or providers of services that would put non-owner participants at a competitive disadvantage. The audits would cover the RTO's actions and decisions with respect to operations and investments. In order for this to be a credible auditing system, the auditors should have clear authority to obtain any information or data necessary to perform their audits and they should have the right to report any findings and recommendations to the Commission without prior approval of the RTO or any of its owners/ members. An initial audit must be performed two years after our approval of the passive ownership arrangements and every three years thereafter.[311] If there is evidence of abuse or we are unable to determine if the ownership interests continue to be passive, the Commission will not hesitate to order appropriate remedial action, including possible termination of passive ownership interests.

We understand that passive ownership arrangements are likely to take many forms and that the Commission has not had much experience in examining these types of arrangements in the context of RTOs. We encourage market participants to investigate the options available for passive ownership to identify those types of arrangements that will provide the greatest assurance of independence. For example, we note that the SEC's Rule 250.7(d) establishes criteria under which entities may have ownership interests that do not trigger SEC jurisdiction under PUHCA. The criteria under Rule 250.7(d) are that: (1) The entity owns the facility as a company, a trustee or holder of a beneficial interest under a trust; (2) the facility is leased under a net lease directly to a public utility company and such facility is to be employed by the lessee in its operations; (3) the company is otherwise primarily engaged in business other than that of a public utility; (4) the terms of the lease have been approved by the regulatory authority having jurisdiction over the lessee; (5) the lease extends for an initial term of not less than 15 years; and (6) the rent reserved under the lease shall not include any amount based, directly or indirectly, on revenues or income of the lessee public utility. While it is unclear whether these exact criteria can be applied to the passive ownership arrangements that may be involved in the formation of an RTO or whether they would address the particular independence issues raised in this Rule, we believe that it would be acceptable for market participants to develop passive ownership arrangements that are purely financial. A passive ownership arrangement that is demonstrated to be purely financial could be relieved of the auditing requirement in this Rule.

Active Ownership Interests in the RTO. We now turn to a discussion of active as opposed to passive ownership. Most commenters used the term ''active'' ownership interests to refer to ownership of voting securities that give the owner the ability to influence or control an RTO's operating and investment decisions. We adopt this definition for purposes of our discussion and will use the terms ''active'' and ''voting'' interchangeably.

Several commenters who were strong proponents of allowing high or unlimited voting interests by market participants argue that in the NOPR the Commission was wrong to focus on any particular ownership percentage. Instead, they contend that what really matters is ''actual control over the day to day affairs of the system, not some arbitrary ownership percent ownership test.'' [312] We agree that the independence of an RTO ultimately depends on who makes the decisions.[313] But control of decisionmaking ultimately depends on who votes and how many votes each party has.

Consequently, we do not think that the Commission can ignore market participants' ownership of voting interests in the RTO.[314] To do so would require us to presume that even though a market participant has the legal right to vote for its own commercial interests, it will choose to vote for the public interest (or the general interests of all market participants). Therefore, we conclude that ownership of voting interests does matter and we cannot remain agnostic about the ownership of voting interests in an RTO by individual market participants, their affiliates or classes of market participants.[315]

a. Active Ownership by Individual Market Participants and Affiliates. A number of transmission customers argue that the cleanest solution would be an ''absolute prohibition'' on ownership of voting interests by any market participant [316] We agree that this would produce a high level of certainty that an RTO is truly independent and anything less than an absolute prohibition introduces some risk. However, if our goal is to encourage the voluntary creation of RTOs, we have to accept that current owners may not relinquish ownership or control of their transmission assets unless it is in their economic interests to do so. In order to create a viable, for-profit, regional transco, at least some current transmission owners must be willing to sell their transmission assets to a new transmission company. Many commenters point out that this voluntary action is not likely to happen if the current owners anticipate large capital gains taxes as a consequence of the sale. The solution, according to many commenters, is to allow current owners to retain some voting interests, some non-voting (*i.e.*, passive) interests or both.

As with passive ownership, the Commission must balance two conflicting goals: the need to assure that any RTO will be truly independent; and of not creating disincentives for transmission owners to voluntarily relinquish ownership or control of their transmission assets. Against the backdrop of these two goals, the specific question that confronts us is how much ownership of active voting interests in RTOs should be allowed for market participants.

Several investor-owned utilities urged us to allow current transmission owners to retain as much as 100 percent voting interest in new for-profit transcos. They argue that we allow 100 percent ownership combined with codes of conduct in the natural gas industry and there is no reason why this model should not also apply to a restructured electricity industry. We disagree with

[311] *See supra* note 304.

[312] CTA at 4.

[313] However, independence does not automatically guarantee that an RTO will be effective in providing non-discriminatory access to the grid. Independence must also be combined with adequate operational and legal authority in order for the RTO to provide non-discriminatory access.

[314] In response to EEI's request for a clarification, we clarify that we are referring only to corporate or shareholder ownership in the RTO itself and not to ownership of transmission facilities under the RTO's operational control. The fact that such facilities are owned by market participants would not be a concern unless the owners retain legal rights and operational responsibilities that make it difficult for an RTO to provide non-discriminatory transmission service to other market participants.

[315] This is not the first time that we have emphasized the importance of voting rights. In various cases dealing with voting shares and voting rules for ISOs, we required that proposed arrangements be reformed to assure that no individual market participant or class of market participants could dominate the decisions of stakeholder committees that advised the ISO's board. *See* New England Power Pool, 88 FERC ¶ 61,079 (1999); Central Hudson Gas and Electric Corp., *et al.*, 88 FERC ¶ 61,229 (1999).

[316] *See, e.g.*, APPA, Consumer Groups and South Carolina Authority.

this recommendation. The two industries, while similar in some respects, also differ significantly in the degree of vertical integration. The electricity industry is starting with a much higher level of vertical integration. As we noted in our NOPR discussion of the complaints filed since the issuance of Order No. 888, it is difficult to monitor compliance with codes of conduct when there is substantial vertical integration (*i.e.*, those who own generation and also own transmission). [317]

Moreover, it is a very intrusive form of regulation and ultimately requires us to be ''chasing after conduct.'' If such regulation is to be effective, we have to be concerned with internal corporate organization and ''who spoke to whom in the company cafeteria.'' [318] This is not light-handed regulation. Therefore, we see little value in replicating this model in the new world of RTOs.

It would be equally unworkable to adopt the recommendations of some transmission customers that we should allow no ownership of RTOs by market participants from the outset. While this is a clean solution and greatly reduces the need to monitor for discriminatory behavior, it also reduces the likelihood that many current transmission owners will voluntarily relinquish ownership or control of their transmission facilities. As a consequence, it is likely to produce significant delays in the creation of RTOs that can support more competitive markets that would benefit consumers. Therefore, the Commission has concluded that it is in the public interest to permit some ownership of RTOs by market participants for a transition period. Within five years of RTO approval, however, active ownership by market participants must end unless the RTO seeks, and the Commission approves, an extension. Any request for extension, including a request occasioned by changed circumstances, must demonstrate that the extension is consistent with the independence standard of this rule and is otherwise in the public interest.

For the transition period, the Commission will establish a safe harbor of five percent for active ownership interests by market participants. We will allow any market participant to own up to five percent of an RTO's outstanding voting securities without the need for case-by-case review by the Commission. An active ownership interest at five percent or lower will be construed as not providing the owner with control.

[317] FERC Stats. and Regs. ¶ 32,541 at 33,704–14.

[318] *Id.* at 33,714.

The Commission will carefully evaluate, on a case-by-case basis, proposals that involve an ownership percentage higher than five percent. In deciding whether to allow active ownership interests that exceed five percent, we will look at various factors including the voting interests held by other class members (*i.e.*, other market participants with similar economic interests), the amount of passive ownership held by market participants, the degree of dispersion of voting interests among other market participants and the general public, and the rights retained by the owners as suppliers of facilities and services to the RTO. While there is no prohibition on RTO proposals that involve higher ownership percentages, it would heighten the concerns identified above and would require justification by the applicants to overcome these concerns.

We note that other Federal regulatory agencies have chosen to use a five percent value in similar situations. The SEC employs a five percent value in deciding when one entity is an affiliate of another under PUHCA.[319] The SEC also requires that any person who becomes a direct or indirect owner of more than five percent of any class of stock of a company must file a public statement with the SEC. In commenting on this latter requirement, the FCC observed that its purpose is ''to ensure that investors are alerted to potential changes in control * * * which confer on their holders the potential for influence or control.'' [320] Less than two months ago, the FCC established a five-percent ''voting share benchmark'' for assessing ownership interests in companies that are cable TV operators. In justifying its decision to stay with a five-percent value, the FCC noted that ''[t]here is a body of more recent academic evidence that tends to confirm our earlier conclusions, demonstrating that interest holders of [five percent] can likely exert considerable influence on a company's management and operational decisions.'' [321] The FCC concluded that ''ownership percentages starting at [five] percent can influence management polices.'' [322]

[319] *See* 15 U.S.C. 79b(a)(11).

[320] Federal Communications Commission, In the Matter of Implementation of the Cable Television Consumer Protection and Competition Act 1999; Implementation of Cable Act Reform Provisions of the Telecommunications Act of 1996; Review of the Commission's Cable Attribution Rules, FCC LEXIS 5243, *53 (October 20, 1999) *citing* Securities and Exchange Commission v. Savoy Industries, Inc., 587 F.2d 1149 (D.C. Cir. 1978), *cert. denied,* 440 U.S. 913 (1979).

[321] *Id.*

[322] *Id.*

We recognize that this Commission has used higher percentages in other contexts. For example, in determining whether a company is an affiliate of a natural gas pipeline or an electric utility, we have applied a rebuttable presumption of control only when a utility or pipeline owns ten percent or more of the company's voting stock. As a general matter, since the success of RTOs will depend on both the perception and reality of independence, the Commission believes that caution requires us to allow only very limited voting interests by market participants. The Commission believes that a lower percentage is necessary in this instance because we allow other market participants with similar economic interests (*i.e.*, members of the same class) to have voting interests. Therefore, we believe that it is appropriate to impose a lower cap to reduce the risk that owners with similar outside economic interests may create a voting bloc. If, after our initial approval, we find evidence that control over the RTO is being exercised by an individual market participant or a class of market participants, we will not hesitate to take appropriate action, including ordering one or more entities to divest their ownership interests in the RTO.

The Commission recognizes that there are risks associated with allowing market participants to have any active ownership interests in an RTO. Even with a five percent active ownership interest, there is a risk that one or more market participants will be able to influence the RTO's decisionmaking process to the disadvantage of other market participants. Consequently, the RTO may fail to be an entity in which ''the control of transmission operation is cleanly separated from power market participants.'' [323] Accordingly, we will require that all market participants divest themselves of any active ownership interests no later than five years after our approval of the RTO. We will consider requests for extensions to this ''sunsetting'' requirement on a case-by-case basis. Any request for extension, including a request occasioned by changed circumstances, will be granted if the requester demonstrates that the extension is consistent with the independence standard of this Rule and is otherwise in the public interest. We will also require that any RTO that proposes active ownership by a market participant must adopt a system of independent compliance auditing to ensure that the active voting interests held by an individual market participant or classes of market

[323] FERC Stats. & Regs. ¶ 32,541 at 33,718.

participants do not convey decisionmaking control.

b. Active Ownership by Classes of Market Participants. In the NOPR, we stated that ''[a]n RTO must have a decisionmaking process that is independent of control of any market participant or class of participants.'' [324] While we suggested a safe harbor of one percent ownership in voting securities by an individual market participant and its affiliates, we did not propose any specific cap on ownership of voting securities by a class of participants. Based on a review of the comments received, we have concluded that a policy on ownership by classes of market participants is necessary to ensure the independence of the RTO. Thus, we will review RTO proposals with respect to class ownership, considering potentially relevant factors such as voting interests held by other market participants or classes of market participants, the degree of passive ownership by market participants, the degree of dispersion of voting interests, and the rights retained by the owners as suppliers of facilities and services to the RTO. We recognize that this is a fact-specific determination that will require the Commission to evaluate, on a case-by-case basis, proposals that involve ownership by more than one market participant. We will adopt a benchmark of 15 percent class ownership. Our willingness to allow ownership by a class of participants that exceeds fifteen percent will depend on the particular circumstances of the filing (*e.g.*, the presence of offsetting voting interests by another class of market participants with competing economic or commercial interests or proposals to sunset active ownership).[325] Moreover, intervenors may also advance arguments that a 15 percent class ownership is inappropriate under certain factual circumstances.

Comments on this issue reflect widely divergent views. SRP criticizes the NOPR for failing to recognize that ''[a]n interest may be considered *de minimis* when viewed in isolation, could still result in effective control when aggregated for a group with common interests.'' SRP contends that while the Commission explicitly recognized the importance of classes in the NOPR, we failed to do anything about it. In contrast, FP&L and others argue that there is no need for any ownership caps for a group of market participants since they will often have conflicting interests. EEI echoes this point by observing that any ''coalitions'' are likely to be ''fragile, short-lived and unlikely to result in a serious threat to the independence of the RTO.'' [326] It also contends that it will be difficult to keep track of ownership interests and to categorize market participants into specific groups with ''alleged common interests.'' Therefore, while EEI proposes a ten-percent cap on ownership interests in voting securities by individual market participants, it recommends that there be no cap on the ownership interests of any group of participants.

In several ISO orders, we rejected proposed governance arrangements because we concluded that the voting weights and rules given to classes or sectors of participants would allow transmission owners to dominate the decisionmaking process.[327] We believe that the concerns that motivated these orders also hold true with respect to ownership of RTOs. It would make little sense to establish a policy on ownership by individual market participants and their affiliates while allowing five or six generators or marketers to group together to force an RTO to adopt a policy that favors their interests.

The Commission is unpersuaded by the assertions that similarly situated market participants will not have a ''nexus of interests.'' While we recognize, for example, that individual generators may actively compete against each other for specific sales, this does not imply that there is a total absence of common economic interests among generators relative to marketers or distributors. If we were to accept this argument, it would require us to ignore the fact that the Commission routinely receives joint pleadings from non-affiliated parties with similar economic interests. Similarly, over the last two years, we have frequently observed various non-affiliated entities within ISOs voting as a bloc on issues where they have similar economic interests (*e.g.,* existing generators voting against new generators who seek lower interconnection charges when they connect to the grid).

There is a second reason why we believe it is necessary to review class or sector ownership of voting securities in RTOs. With ISOs, we have allowed sector or class representation on the advisory and technical committees that are charged with giving advice or making recommendations to non-stakeholder governing boards. We have accepted these arrangements even though the votes of some classes exceed 20 percent because all other classes are represented and have roughly equal voting power. Thus, independence is achieved through a diffusion of voting power among all the affected classes. While this arrangement may work for ISOs that are typically non-profit and non-share corporations, we do not think it is viable option for RTOs that have ownership shares that must be purchased. In particular, we cannot assume that all affected classes of market participants will have the financial resources to purchase ownership interests that would guarantee them a vote at the table. Therefore, we cannot presume that there will be a balance of voting power as was the case for the ISOs. In the absence of such countervailing voting blocs, we believe that it is necessary to establish lower limits on the amount of voting shares that can be owned by members of any one class of market participants.

Based on our experience to date, we do not think it is impractical to define classes of market participants with similar economic interests. This has been routinely done as part of the governance design in every one of the ISOs that we have approved. The Commission will not establish categories of classes in this Final Rule. Instead, we will allow each RTO to propose the classes that it believes are relevant to its region. However, we are inclined to define such classes broadly to avoid bypassing the class cap through narrowly defined classes.

In addition, we will require independent compliance auditing to ensure that market participants that have ownership interests will not use these ownership interests to put other non-owner market participants at a competitive disadvantage.[328]

The auditing should be performed by individuals or organizations that are not affiliated with the owners or RTO. The auditors would have clear authority to obtain any information or data necessary to perform their audits, and they would have the right to report any findings and recommendations to the Commission without prior approval of the RTO or any of its owners/members. An initial audit should be performed two years after our approval of the RTO. This will be the only audit required for active ownership unless the RTO or the active owners request and receive approval for an extension of active ownership interests beyond five years. If such an extension is granted, then follow-up compliance audits must be performed at three year intervals,

[324] *Id.* at 33,727.

[325] *See Alliance Companies*, supra note 48.

[326] EEI Reply Comments at 21.

[327] *See* New England Power Pool, 88 FERC ¶ 61,079 (1999); Central Hudson Gas and Electric Corp., *et al.*, 88 FERC ¶ 61,229 (1999).

[328] *See supra* note 304.

beginning with a three-year audit filed along with any request for extension.

As we discussed above with respect to passive ownership, applicants will have a continuing obligation to inform the Commission of any changed circumstances regarding active ownership. Moreover, the Commission would expect auditing for compliance with the individual and class caps established at the time of RTO approval. Where feasible, the auditors would rely on publicly available information on ownership interests (*e.g.,* SEC data sources). Where such information is not publicly available (*e.g.,* individual ownership interests of less than five percent), the auditors should have the authority to obtain this information from market participants and their affiliates. Any market participant that wishes to have an ownership interest in an RTO must agree to provide this information to the auditor or the Commission upon request. We would expect that market participants will comply with both the individual and class caps at all times. If the auditor finds that either cap has been violated, it must notify the Commission and the affected owners immediately and also recommend a remedy.

Since the caps do not guarantee a lack of control, the Commission expects that the auditors will also look for evidence of control over RTO decisionmaking at lower levels of ownership. These audit reports would be closely reviewed by the Commission and if there is evidence of abuse or unwillingness to cooperate with the auditors, the Commission will not hesitate to order owners to divest themselves of their active ownership interests.

RTO Governing Boards. Many commenters urge us to impose specific, detailed requirements on RTO governance. Commenters make recommendations on many different aspects of governance: the desirability of stakeholder, non-stakeholder or hybrid boards, the size of boards, the relationship between non-stakeholder boards and stakeholder advisory groups, the number of classes for stakeholder boards, the appropriate voting entitlements for individual classes on a stakeholder board; and optimal voting rules. Most of the recommendations seemed to be targeted for RTOs that are ISOs. In the Final Rule, we have decided not to impose any specific requirements on RTO governing boards other than the general requirement that they must satisfy the overall principle that their decisionmaking process should be independent of any market participant or class of participants. We have opted not to impose more detailed governance requirements for three reasons.

First, we anticipate that RTOs will take many different forms that reflect the needs and different starting points of each region. We expect to see proposals from ISOs, transcos and hybrids. It is unlikely that a single approach to governance will work for the different types of RTOs that are likely to emerge. At this early stage, it would be counterproductive to impose a ''one size fits all'' approach to governance when RTOs may differ significantly in structure and patterns of ownership.

Second, our experience to date has been largely limited to reviewing governance proposals of ISOs that operate but do not own transmission facilities. A governance model that works for an ISO may not be appropriate for transcos or other types of for-profit transmission enterprises.

Third, even among the ISOs, there are different models of governance. As we noted in the NOPR, the dominant governance model (PJM, New England, New York and the Midwest) for ISOs is a two-tier form of governance. The top tier consists of a non-stakeholder board, while the lower tier consists of advisory committees of stakeholders that may recommend options to the non-stakeholder board. Generally, the top tier has the final decisionmaking authority.[329] In contrast, California, employs a decisionmaking board for its ISO that consists of both stakeholders and non-stakeholders representatives. And we note that the recently passed Texas restructuring law would require a pure stakeholder governing board for the ERCOT ISO. Given the variety of governance forms that exist or are proposed for ISOs and the limited experience with these different approaches, the Commission believes that it is premature to conclude that one form of governance is clearly superior to all other forms in every situation.

Therefore, we will not mandate detailed governance requirements for RTO boards. Instead, the approach that we adopt in the Final Rule is that any RTO governance proposals, whether from an ISO, transco or a hybrid arrangement, will be judged on a case-by-case basis against the overarching standard that its decisionmaking process must be independent of individual market participants and classes of market participants.[330]

While we are not imposing any other specific requirements, the Commission believes that it is appropriate to give some general guidance based on the governance arrangements that we have reviewed to date. Where there is a governing board with classes of market participants, we would expect that no one class would be allowed to veto a decision reached by the rest of the board and that no two classes could force through a decision that is opposed by the rest of the board. Where there is a non-stakeholder board, we believe that it is important that this board not become isolated. Both formal and informal mechanisms must exist to ensure that stakeholders can convey their concerns to the non-stakeholder board. Where there are stakeholder committees that advise or share authority with a non-stakeholder board, it is important that there be balanced representation on the stakeholder committees so no one class dominates its recommendations or its decisions.

We note that this general guidance is based on our experience with governance proposals of ISOs. The Commission recognizes that these observations may not be completely relevant for an RTO that intends to operate as a for-profit transmission company. Nevertheless, we emphasize that the common element for all types of RTOs must be that they satisfy the threshold principle that their decisionmaking should be independent of market participants.

Role of State Agencies. We do not impose any specific requirements on the role of state agencies in RTOs. Such specificity would be counterproductive in light of the variation in the legal responsibilities of state commissions and RTO design across regions. However, we agree with NARUC that state commissions ''should fully participate in RTO formation and development.'' When we undertake our collaborative efforts with the industry after issuance of the Final Rule, we encourage state commissions and other state agencies to play a key role in this effort. State involvement is important for several reasons, especially where RTOs are a critical element of the retail choice programs of many states. State commissions are in a unique position to assess whether a particular RTO design will help or hinder their efforts to promote retail competition.

[329] One exception is the New York ISO where decisionmaking is explicitly shared by a non-stakeholder Board of Directors and stakeholder Management Committee. Modification of the ISO tariffs under the FPA requires approval of the ISO Board and the Management Committee. If they fail to agree on a modification, either the Board or the Management Committee may make a filing under FPA section 206. *See* Central Hudson Gas & Electric Corp., *et al.,* 88 FERC ¶ 61,138 (1999).

[330] We will require every ISO to submit an audit of the independence of its governance process two years after its approval as an RTO.

Once an RTO becomes operational, it appears that most states believe that it would be inappropriate for a state official, whether a state commission representative or some other state employee, to serve as a voting member of an RTO board. We note that NECPUC, representing the six New England state commissions, was joined by most other state commissions and commenters from other sectors of the industry in recommending that state officials should not be voting members of any RTO governing body. ISO–NE presents three reasons why it would be problematic for a state official to serve as a voting member of an RTO governing board. First, it would create a conflict between the state official's duties as an RTO board member and his or her regulatory or legal responsibilities at the state level. Second, in the case of a multi-state RTO, it would be difficult for an official of one state to represent the interests of others states if the state interests are in conflict. Third, the solution of allowing each state to have its own voting member on the RTO board could lead to large and unwieldy boards for multi-state RTOs.

While most commenters agreed that state officials should not serve as voting members of RTO boards, most of these same commenters were comfortable with allowing state officials to serve as *ex officio* members. It was thought that state officials would be better informed in making their own decisions if they could closely observe the considerations and constraints that were weighed by the RTO in making its decisions. It was thought that the ability of state officials to observe the RTO's decisionmaking process would be especially useful if the RTO had to recommend one or more expansions to the existing grid.

While we see considerable merit in the arguments that state officials should not be voting members of an RTO governing board (and note that most state commissions share this view), the Commission is not imposing such a prohibition. Since RTOs do not yet exist, it would be premature to conclude that state officials should not participate as voting members of RTO boards. There may be special circumstances in some regions that would make it in the public interest to give voting rights to one or more state government representatives. Therefore, we will be willing to entertain such proposals and perhaps revisit the issue after we gain more experience.

Section 205 Filing Rights. In the NOPR, we proposed that the RTO must have exclusive and independent authority to file changes in its transmission tariff under section 205 of the Federal Power Act. This proposal triggered hundreds of pages of comments. Upon consideration of the comments received, as discussed below, we will modify our proposal, in part, to make clear that transmission owners who do not also operate their transmission facilities retain certain section 205 rights.

Most commenters on this issue fall into two categories. Those who oppose the proposal in the NOPR argue that it is bad law and bad policy. They contend that the Commission does not have the legal authority to grant section 205 rights over their transmission facilities to some other entity. While a transmission owner may voluntarily cede this right to an RTO, they argue that the Commission cannot compel a transmission owner, either directly or indirectly, to give up this legal right. Many transmission owners, representing IOUs, public and cooperative systems, argue that the transfer of this right to an RTO would increase their risk of recovering revenues to which they are lawfully entitled. On the other hand, those who support the proposal argue that it is a necessary and logical implication of our previously stated policy that the ''[a]uthority to act unilaterally * * * is a crucial element of a truly independent transmission provider.'' [331] They contend that an RTO will not be able to function as an independent and neutral transmission provider if it has to seek the approval of transmission owners or other market participants every time it wishes to modify its tariff. They point to numerous tariff changes that the various ISOs have had to make as real world evidence of their need to move quickly and make filings at the Commission when they encounter a tariff problem that needs to be corrected.

Based on the comments received, we reaffirm our determination that RTOs, in order to ensure their independence from market participants, must have the independent and exclusive right to make section 205 filings that apply to the rates, terms and conditions of transmission services over the facilities operated by the RTO. This determination, however, is subject to several important clarifications discussed below.

We recognize that for some RTOs (in particular, ISOs), both the transmission owners and the RTO will be public utilities with respect to the same transmission facilities,[332] *i.e.,* one or more entities will own the facilities and a different entity will operate the facilities and actually sell the transmission provided by the facilities, and that this presents a somewhat unusual situation insofar as sections 205 and 206 of the FPA are concerned. The FPA does not explicitly address who has filing authority or responsibility in this circumstance. We conclude that while the RTO must have independent and exclusive authority to propose changes in the rates, terms and conditions of transmission service provided over the facilities it operates, it also is reasonable for the transmission owners to retain certain independent section 205 filing rights with respect to the level of the revenue requirement that the transmission owners receive from the RTO and that the RTO, in turn, will collect from the transmission customers through its rates. We therefore clarify that a transmission owner must have independent authority to set the level of its portion of the revenue requirement to be collected by the RTO.[333]

Importantly, we further clarify that we expect the authorities of the transmission owners and the RTO to be exercised as follows. The transmission owners may make section 205 filings to establish the payments that the RTO will make to the transmission owners for the use of the transmission facilities that are under the control of the RTO; the RTO, in turn, will make section 205 filings to recover from transmission customers the cost of the payments it makes to transmission owners as well as its own costs, and propose any other changes in the rates, terms and conditions of service to transmission customers. Thus, the transmission owners may have on file a tariff that assures their recovery of transmission revenues from the RTO and, while they may be affecting the level of the RTO's revenue requirement, they will not be permitted to make section 205 filings for RTO services to transmission customers and will not interfere with the independence of the RTO to file proposed changes to the open access tariff.[334]

[331] New England Power Pool, 70 FERC ¶ 61,374 at 62,585 (1997).

[332] Under FPA section 201(e), a public utility is any person who owns *or* operates jurisdictional facilities.

[333] Of course, a transmission owner may voluntarily agree to relinquish this right during the RTO negotiation process or subsequently.

[334] We note that some existing ISOs have adopted an approach where the transmission owners' revenue requirement is filed with the Commission in a separate transmission rate filing (*e.g.,* California ISO), while others incorporate the revenue requirement of the transmission owners, as changed from time to time, in the ISO's tariff. In either case,

We believe this division of filing rights reflects a reasonable interpretation of the FPA as applied to these circumstances, and that it appropriately balances the need to ensure the independence of the RTO with the need to provide transmission owners the opportunity to recover revenues. To avoid unnecessary disputes and coordinate the interaction of these independent section 205 filings, we will require the RTO and the transmission owners to give prior notice to each other of any planned section 205 filings. Further, we strongly encourage transmission owners and RTOs to resolve rate issues prior to the filing of proposed rate changes.

We recognize that the division of filing rights described above may not be the only way to accommodate the concerns raised. Accordingly, the Commission will entertain other approaches as long as they ensure the independent authority of the RTO to seek changes in rates, terms or conditions of transmission service and the ability of transmission owners to protect the level of the revenue needed to recover the costs of their transmission facilities. The Commission will require RTOs to provide a detailed description of the process to allow us to assess its fairness and workability.

2. Scope and Regional Configuration (Characteristic 2)

The NOPR proposed as the second minimum characteristic of an RTO that the RTO must serve an appropriate region—a region of sufficient scope and configuration to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets.[353] The NOPR noted that there is likely no one ''right'' configuration of regions and proposed to establish a set of factors that encourage appropriate regional configuration without prescribing boundaries. The NOPR suggested that a region that is large in scope would facilitate the effective performance of many of the RTO's functions, but also recognized that there may be factors that might limit how large an RTO should be.[336] The NOPR also proposed a set of factors that may affect the location of regional boundaries. These factors indicate that boundaries should facilitate essential RTO functions and goals, recognize trading patterns, mitigate the exercise of market power, do not unnecessarily split existing control areas or existing regional transmission entities, encompass contiguous geographic areas and highly interconnected portions of the grid, and take into account useful existing regional boundaries (such as NERC regions) and international boundaries. The NOPR put forth for discussion the appropriateness of existing configurations, such as the three electric interconnections within the continental United States, the ten NERC reliability councils, and the 23 NERC security coordinator areas.

The NOPR also requested comments on what portion of the transmission facilities within an appropriate region the RTO must control in order to be approved as an RTO. The Commission recognized that it might be difficult to obtain 100 percent participation of all transmission owners within a region, but that, on the other hand, it would not be appropriate to approve an RTO proposal that included only a small portion of the facilities of the region. The Commission also requested comments on how much deference the Commission should give to regions proposed to us, and to what extent state commission approval or disapproval should be taken into account.

a. How Should Initial Boundaries be Established? Comments. Most commenters agree with the Commission's proposal not to initially prescribe the boundaries for appropriate regions.[337] Among the rationales asserted by these commenters is that this is a matter best left in the first instance to the stakeholders in the various regions,[338] there should be deference to proposals by transmission owners and market participants,[339] FERC should give deference to state commissions on scope and configuration,[340] boundaries should be determined naturally in a way that facilitates market transactions,[341] and size and configuration must be determined on a case-by-case basis.[342]

However, some commenters argue that the Commission should prescribe regional boundaries. APPA, East Texas Cooperatives, TDU Systems and the Michigan Commission urge that the Commission use section 202(a) authority to establish initial boundaries. APPA asserts that the Commission should establish a rebuttable presumption in favor of specific regional district boundaries based on the topology of the transmission network to enhance system security. East Texas Cooperatives argues that after the Commission established regional districts, the burden would be on those proposing different regions to show that they provide at least the benefits of the prescribed districts. Michigan Commission states that the electricity market is currently too immature to determine by itself the size of the markets, and that firm guidance is needed rather than allowing the RTO boundaries to be set by participants.

Several other commenters do not go as far in asserting that the Commission should initially set boundaries, but argue that the Commission should take a strong role in assuring proper boundaries. For example, Cinergy urges that the Commission be aggressive in establishing boundaries consistent with the proposed criteria, noting that the willingness of the Commission to exercise its authority over boundaries will determine the success of the Commission's restructuring efforts. Coalition of Alliance Users maintains that the Commission should take a direct and active role in formulating RTO boundaries. WEPCO believes that the role of the Commission should be to set criteria that encourage the establishment of sensible RTO boundaries. Project Groups assert that if the stakeholders in a region do not determine boundaries by the end of 2000, the Commission should make the determinations. LG&E states that while the Commission should show deference to voluntary RTOs, it should not hesitate to disapprove proposals with geographic shortcomings.

Commenters express a variety of views regarding whether particular regional configurations would be appropriate. Some commenters support interconnection-wide RTOs as a desirable goal,[343] while others regard either an Eastern or Western interconnection RTO as unworkably large.[344]

Commenters offer specific ideas about the number and placement of RTOs. PG&E states that the long-term goal should be four or five RTOs nationwide.

only the ISO is authorized to make filings that change the tariff sheets in the ISO's tariff.

[335] FERC Stats. and Regs. at 33,729.

[336] *Id.* at 33,730.

[337] *See, e.g.,* South Carolina Authority, Cleco, SRP, LG&E, Detroit Edison, Wyoming Commission, Entergy, UtiliCorp, NECPUC, MidAmerican, Enron/APX/Coral Power, Duke, NASUCA, Industrial Consumers, Connectiv, Massachusetts Division, Iowa Board.

[338] *See, e.g.,* South Carolina Authority, NASUCA, Florida Power Corp.

[339] *See, e.g.,* Entergy, MidAmerican.

[340] *See, e.g.,* Southern Company, NECPUC, Nine Commissions, Florida Commission.

[341] *See, e.g.,* Duke, FirstEnergy, Allegheny, Iowa Board.

[342] *See, e.g.,* NYPP.

[343] *See, e.g.,* South Carolina Authority, Conlon, Industrial Consumers, First Rochdale, Los Angeles, PG&E, Sonat.

[344] *See, e.g.,* South Carolina Authority, Desert STAR, MidAmerican, TDU Systems, CREDA, SNWA, CRC, Platte River, PSNM, SRP, Metropolitan.

Williams argues for 3 to 10 RTO nationwide, while Project Groups advocates 3 to 12 RTO nationwide. WEPCO proposes the formation of five RTOs: (1) three in the Eastern interconnection (one covering MAPP, MAIN, ECAR and portions of SPP; one covering SERC, Florida and the rest of SPP; and one covering NPCC and MAAC); (2) one for WSCC; and (3) one for ERCOT. APPA, supported by East Texas Cooperatives, suggests: (1) no more than three RTOs in the West; (2) the combination of PJM, NY ISO and ISO–NE into one RTO with the possible participation of Ontario; (3) the combination of the Alliance RTO, Midwest ISO, and MAPP into one RTO; (4) Kansas to the Carolinas under one RTO; and (5) separate RTOs for Florida, ERCOT and Hydro-Quebec.

With respect to specific regions, ISO–NE contends that it already operates a region of appropriate size and configuration. Mass Companies agrees that ISO–NE is an appropriate region. NYC argues that the formation of a northeastern RTO with a broader geographic scope than the NY ISO would help remove existing institutional impediments to the construction of new transmission lines. American Forest argues that PJM is too small, while NASUCA and Mid-Atlantic Commissions believe that PJM satisfies the size criteria. Some commenters object to a split between the area represented by the proposed Alliance RTO and the Midwest ISO.[345] Most of the Florida commenters assert that peninsular Florida represents an appropriate region.[346] For example, Florida Commission claims that peninsular Florida is a large and efficient marketplace that does not share parallel flows with other electrical regions; however, it states that the Florida panhandle could be in a region with all of SERC or a subregion of SERC.

Although some commenters encourage a Western interconnection-wide RTO, the majority of commenters support three or four RTOs for the Western interconnection, noting that the interests in the WSCC are too diverse and the area too large for control by a single entity.[347] Cal ISO contends that California satisfies the minimum size criteria, but does not represent the maximum feasible area. Commenters from the Pacific Northwest generally agree that a region including Washington, Oregon, and all or portions of Idaho and Montana is distinct enough to warrant an RTO limited to that area.[348] CREDA and Platte River envision one RTO for the Pacific Northwest, one for California and one for the Rocky Mountain/Desert Southwest area; CRC suggests a similar alignment, with the exception of the Rocky Mountain and Southwest areas as separate RTOs.

A number of commenters make the point that, regardless of where RTO boundaries are drawn, it is important that there be integration and coordination among RTOs.[349] NERC believes that there are two seams issues: reliability practices across seams and market practices across seams. TDU Systems suggests that there be a set of regions for reliability/operations purposes within a larger region for rates and scheduling. Industrial Consumers state that, if multiple RTOs are formed within an interconnection, RTOs should be required to coordinate their operations to collectively ''simulate'' an interconnection-wide RTO. Cinergy suggests that, if there were more than one RTO in a large interconnection, a ''super'' RTO could be established to operate and coordinate inter-RTO activities. Montana Commission states that RTO boundaries are less important than ensuring that seams do not interfere with the market, and proposes, as do others such as Ontario Power and CMUA, that the Commission require adjacent RTOs to embody consistent methods of access, pricing, and congestion management to encourage seamless trading. PacifiCorp asserts that reciprocity agreements among RTOs may be easier to achieve than having all parties in a large region agree to one RTO. Allegheny suggests that appropriate transmission pricing could provide some of the same benefits as a large RTO.

Several commenters express concern that multiple RTO proposals for the same region will be submitted. Indiana Commission contends that the NOPR leaves the door open for more than one RTO proposal for approximately the same wholesale power market region and this could limit the operational efficiency and increase the cost of transmission in the region. It suggests that the Commission consider requiring formal mediation or play an assertive role in such circumstances. Snohomish suggests favoring the RTO proposal that is negotiated pursuant to the most open process that included consumers, transmission dependent utilities and others with a vital interest in the effective and efficient operation of the transmission grid. Midwest ISO Participants submit that the proponents of multiple RTOs meet a heavy burden and demonstrate the need for more than one RTO. In particular, it would require demonstration that the proposals: do not balkanize the market; allow for effective congestion relief; maintain reliability; facilitate construction of new transmission facilities; and allow for effective tariff administration and unbiased ATC determination throughout the region.

Commission Conclusion. We adopt the NOPR proposal on this characteristic. All RTO proposals filed with us must identify a region of appropriate scope and configuration. The scope and configuration of the regions in which RTOs are to operate will significantly affect how well they will be able to achieve the necessary regulatory, reliability, operational, and competitive benefits.

As proposed in the NOPR, we will not at this time prescribe initial boundaries for RTOs. Section 202(a) of the FPA does give us the authority, after consultation with state commissions, to fix and modify boundaries for regional districts for the voluntary interconnection and coordination of facilities. We acknowledge those commenters who believe that it may be more efficient for the Commission to establish at least a rebuttable presumption that particular boundaries are appropriate starting points. However, we conclude, as a matter of policy, that we should not attempt to draw boundaries at this time. We are convinced that the transmission owners, market participants, and regulators in a particular region have a better understanding of the dynamics of the transmission system in that region, and that they should, at least in the first instance, propose the appropriate scope and regional configuration of an RTO. There are many technical considerations involved in discerning the appropriate scope and regional configuration of an RTO, and we believe that those most familiar with such considerations in a region are in a better position to propose a workable solution.

As noted above, some commenters advocate that the NERC regions be starting points; others advocate that the Interconnections be the goal; and still others propose specific configurations that would divide the Nation as many as three to 12 RTOs. Consistent with our decision to let the parties take the initiative to propose what is appropriate for their region, we will not specifically

[345] *See, e.g.,* Michigan Commission, South Carolina Authority, Midwest ISO, Midwest ISO Participants, NASUCA.

[346] *See, e.g.,* Florida Commission, JEA, FP&L, Florida Power Corp., Tallahassee, Gainesville.

[347] *See, e.g.,* SRP, Metropolitan.

[348] *See, e.g.,* Seattle, PGE, Industrial Customers, BC Hydro, Powerex, Tacoma Power, PNGC.

[349] *See, e.g.,* South Carolina Authority, SPP.

endorse any particular scheme for RTO configuration.

This is not to say, however, that we will deem appropriate any regional configuration proposed. As stated in the regulatory text for this characteristic, an appropriate region is one of sufficient scope and configuration to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. A proposed RTO could simply be too limited to satisfy several of the necessary functions. Further, we are aware that transmission owners could seek to gain strategic advantage by the way an RTO is formed. For example, an RTO could be placed to act as a toll collector on a critical corridor.[350] An RTO could propose a configuration that interferes with the formation of a larger, more appropriately configured RTO.

As we review a proposal by a regional transmission entity for its scope and regional configuration, if we determine that the scope is inappropriate, that entity will not be deemed to be an RTO, and its participants will not be deemed to be RTO participants.[351] In response to the commenters questioning what the Commission would do if it received multiple RTO proposals for a region, we note that we hope the collaborative process we are encouraging in this Final Rule would foreclose that circumstance. However, if we are faced with multiple proposals, we would have to determine which RTO proposal best meets the objectives of this Rule.

As we stated in the NOPR, we are aware that there is likely no one ''right'' configuration of regions. One particular boundary may satisfy one desirable RTO objective and conflict with another. We recognize here, and elsewhere in this Final Rule,[352] that the industry will continue to evolve, and the appropriate regional configurations will likely change over time with technological and market developments. The Commission is also mindful of the interests of individual states regarding RTO boundaries. Given all these considerations, the Commission believes that the public interest will best be served if we provide guidance in this Final Rule, in the form of factors that affect appropriate regional configuration, without actually prescribing boundaries.

b. Scope and Configuration Factors. Comments. A large number of commenters agree that the factors listed in the NOPR for determining a proper scope and configuration for an RTO are generally appropriate.[353] Industrial Consumers propose that the factors be codified as part of our regulations. Florida Commission, on the other hand, argues that the factors should not be mandated as part of the Commission's regulations.

Many commenters argue that the RTO region should be as large as possible, *i.e.,* bigger is better.[354] Several commenters suggest the minimum size should be the NERC regions.[355] Conlon suggests a minimum area should be one containing a load of 50,000 MW. PJM states that its organization demonstrates that a very large RTOs is feasible, in that it manages a grid serving more than 57,000 MW of generation and containing more than 8,000 miles of high voltage transmission lines. PJM states that even larger control areas are possible as technology advances. PJM/NEPOOL Customers, claiming that all potential factors that might limit size can be overcome, argue that the Commission should not conclude that there are factors that limit size. As discussed below with respect to the congestion management function, some commenters make a particular point of emphasizing the importance of large scope to effective congestion management.[356]

Other commenters argue that bigger is not necessarily better and that there are factors that limit size.[357] CMUA argues that the role of security coordinator and operational characteristics of a region may limit geographic scope. STDUG claims that size breeds inefficiency. Several commenters claim that requiring maximum scope upon creation may discourage RTO formation or make it more costly and take longer to achieve.[358] NYPP expresses concern that, if an RTO is too large, it may not be able to handle local reliability issues. Other commenters believe that the ability to plan new transmission facilities may limit scope.[359] AEPCO expresses concern that the voice of smaller participants could be lost in a larger RTO. Florida Power Corp. claims that there may be a security risk associated with concentrating control of too large an area into a single facility, and that large areas of non-pancaked rates may eliminate incentives for proper generator siting decisions. A number of commenters believe that either the Eastern interconnection or the Western interconnection is too large an area to be controlled by one RTO.[360] New York Commission argues that the Commission should recognize that experience must be gained in stages before an RTO encompassing an entire interconnection can be implemented. Several commenters in the Pacific Northwest cite the failed attempt to create IndeGo as evidence that trying to create too large an RTO is unworkable, and at some point ''bigger'' creates more problems than it solves.[361]

Some commenters offer subjective parameters for the scope of an RTO. For example, SNWA proposes that the RTO be large enough to accommodate as many market participants as possible, but not so large as to be overly burdensome to manage. SRP argues that a balance must be struck between an RTO that is too small to cover a meaningful wholesale power market and one that is too large to form and operate effectively. TDU Systems argue that RTOs should comprise the largest regions that could operate in a coordinated fashion within a short period of time with reasonable investments of funds.

A number of commenters emphasize particular factors that they consider important in determining scope and configuration. Some commenters assert that reliability and system security should be the primary determinant of scope and configuration.[362] Others place prime importance on trading patterns and facilitating market transactions.[363] EEI states that the most efficient size and configuration of an RTO should be left to the market to determine. Other commenters propose electrical

[350] *See* Statement of Ohio Commission Chairman Craig Glazer, RTO Conference (St. Louis), transcript at 85–87.

[351] The proposal could be accepted, however, as something less than an RTO that represents an improvement over the status quo.

[352] *See* section F on Open Architecture.

[353] *See, e.g.,* UtiliCorp, Desert STAR, Midwest ISO Participants, Metropolitan, NECPUC, LG&E, PJM/NEPOOL Customers, Midwest Municipals, Industrial Consumers, Dairyland, TDU Systems, ISO–NE, Midwest Energy, APX, APPA, Cal ISO.

[354] *See, e.g.,* Cinergy, American Forest, EPSA, UtiliCorp, PG&E, NSP, Pennsylvania Commission, NJBUS, LG&E, Enron/APX/Coral Power, NASUCA, PJM/NEPOOL Customers, Cal ISO, Texas Commission, Conlon, Dynegy, Nine Commissions, Michigan Commission, Lincoln, WPSC, First Rochdale, East Texas Cooperatives, Los Angeles, Ohio Commission, EME, Ontario Power, H.Q. Energy Services, Ogelthorpe, UMPA, PG&E, Indiana Commission.

[355] *See, e.g.,* Cinergy, WPSC, Lincoln, Ohio Commission, PG&E.

[356] *See, e.g.,* LG&E, ComEd, Midwest ISO Participants, Midwest ISO.

[357] *See, e.g.,* AEPCO, Tallahassee.

[358] *See, e.g.,* Enron/APX/Coral Power, FirstEnergy, Tri-State.

[359] *See, e.g.,* Dairyland, Minnesota Power.

[360] *See, e.g.,* South Carolina Authority, Desert STAR, MidAmerican, TDU Systems, CREDA, SNWA, CRC, Platte River, PSNM, SRP, Metropolitan.

[361] *See, e.g.,* Industrial Customers, Powerex, Tacoma Power.

[362] *See, e.g.,* CMUA, APPA, Florida Commission, Minnesota Commission.

[363] *See, e.g.,* UtiliCorp, Reliant, Duke, South Carolina Commission, NU, Florida Power Corp., Detroit Edison.

configuration and physical power flows as important factors.[364] CREDA and Desert STAR argue that the preservation of a Federal Power Marketing Administration project marketing area is an important consideration. Chelan argues that cost shifts need to be considered in determining scope. Platte River contends that established security coordinators should be a factor. Southern Company argues that joint ownership agreements should be a factor. Tacoma Power claims that traditional business relationships and social and political commonality are factors that affect scope.

Commenters are divided on whether points where transmission facilities are constrained should be used as an RTO boundary or internalized within an RTO. Some commenters claim that constraints should be internalized to the extent possible and not constitute boundaries between regions.[365] NERC states that boundaries should not be placed at weak interconnections because a single entity is better able to strengthen them. On the other hand, other commenters believe that constrained facilities should constitute the boundaries, either because they may form a natural boundary between robust systems or because it makes more sense to internalize markets than to internalize constraints.[366] APPA states that, because it is not possible to internalize all constraints, the goal should be to alleviate or mitigate the effects of interregional constraints through additional construction and RTO operating rules and pricing policies. NECPUC argues that it does not matter where constraints are if compatible methods of locational pricing are adopted by contiguous RTOs. MidAmerican and Duke assert that constraints are not natural boundaries between regions because the location of points of constraint change over time as market conditions change. Several commenters, such as Dairyland and Desert STAR, take the position that the issue whether to design RTO boundaries at constrained interfaces cannot be stated generically, and must be decided on a case-by-case basis.

Commission Conclusion. The factors we believe should be used to develop appropriate regions are set out here and called regional configuration factors. These cover such considerations as how large a region should be and how boundaries should be evaluated. We do not see a benefit to placing them in regulatory text, as suggested by one commenter, and we will not do so. The factors are intended as guidance and, as such, must necessarily be applied flexibly.

Regional Configuration Factors. As stated above, the principal consideration in evaluating the appropriate scope of an RTO is that such scope must permit the RTO to perform its functions effectively. As we stated in the NOPR, many of the characteristics and functions for an RTO proposed in this section suggest that the regional configuration of a proposed RTO should be large in scope.[367] For example:

- Making accurate and reliable ATC determinations: An RTO of sufficient regional scope can make more accurate determinations of ATC across a larger portion of the grid using consistent assumptions and criteria.
- Resolving loop flow issues: An RTO of sufficient regional scope would internalize loop flow and address loop flow problems over a larger region.
- Managing transmission congestion: A single transmission operator over a large area can more effectively prevent and manage transmission congestion.
- Offering transmission service at non-pancaked rates: Competitive benefits result from eliminating pancaked transmission rates within the broadest possible energy trading area.
- Improving Operations: A single OASIS operator over an area of sufficient regional scope will better allocate scarcity as regional transmission demand is assessed; promote simplicity and ‘‘one-stop shopping’’ by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites.
- Planning and coordinating transmission expansion: Necessary transmission expansion would be more efficient if planned and coordinated over a larger region.

We note that the comments on this issue express a range of views. Many commenters assert that the bigger the RTO is the better, and that there really are no serious limitations to RTOs representing loads as large as several hundred thousand megawatts. Other commenters suggest a number of considerations that may militate against RTOs that are too large, including the role of security coordinator, operational characteristics, costs of formation, local reliability issues, and the effect on smaller participants. In the NOPR, we recognized that there may be a limitation on how many facilities or transactions can be overseen reliably by a single operator, imposed either by hardware design or costs, or imposed by human limitations to process the required amount of information. We further recognized that the difficulty and cost of transferring operational control over many transmission systems to one RTO may affect regional configuration. We also noted that, as regions get larger and involve more existing owners of transmission, reaching consensus on an appropriate transmission rate design for the region may prove challenging.

We note that a number of commenters make the point that, at least for some purposes and functions, the scope of an individual RTO is less important if it is part of a group of RTOs that have adequately eliminated the negative effects of ‘‘seams’’ between itself and the other RTOs. NERC identifies two seams issues: reliability practices across seams and market practices across seams. We further note that other commenters suggest that large RTOs could be ‘‘simulated’’ through coordinated operations and consistent methods of access, pricing, and congestion management, and that there may be different acceptable scopes for reliability and operations purposes on one hand, and rates and scheduling on the other.[368] We also detect a common theme that runs through a number of comments: large geographic size is most important for trading areas. Thus, the concept of large ‘‘seamless trading areas’’ for power emerges as a ‘‘scope’’ issue that is distinct from the scope of the region for organizing the transmission functions of an RTO.

We conclude that a large scope is important for an RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. Adequate scope is not necessarily determined by geographic distance alone; other factors include the numbers of buyers and sellers covered by the RTO, the amount of load served, and the number of miles of transmission lines under operational control. The scope must be large enough to achieve

[364] See, e.g., South Carolina Authority, Williams, NSP, Dynegy.

[365] *See, e.g.,* Industrial Consumers, First Rochdale, Minnesota Power, STDUG, NARUC.

[366] *See, e.g.,* Ohio Commission, EAL, Florida Power Corp.

[367] This reiterates the conclusion we reached in the eleven ISO principles in Order No. 888, where we stated that ‘‘[t]he portion of the transmission grid operated by a single ISO should be as large as possible.’’ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,731.

[368] In a recent conference to address interregional ISO coordination in the northeast, the three northeast ISOs (ISO New England, New York ISO, and PJM ISO) and other market participants discussed current and future coordination efforts among the ISOs intended to simplify market transactions and enhance reliability in the northeast. *See* http//www.dps.state.ny.us/isoconf.htm.

the regulatory, reliability, operational and competitive objectives of this Rule.

We are receptive to flexible and innovative ways for an RTO to achieve sufficient scope. Where a proposed regional transmission entity may be of sufficient scope for some RTO purposes, but not others, an RTO may be able to achieve sufficient ''effective scope'' by coordination and agreements with neighboring entities, or by participating in a group of RTOs with either hierarchical control or a system of very close coordination. We do not foreclose the possibility that an RTO may satisfy some of the minimum characteristics and functions by itself, while satisfying others through a strong cooperative agreement with neighboring RTOs to create a ''seamless trading area.'' The functions of a large RTO may be met by eliminating the effect of seams separating smaller RTOs through a contract or other coordination arrangement. One of our concerns about an RTO's scope is that the existing impediments to trade, reliability, and operational efficiency be eliminated to the greatest extent possible. However, an RTO application that proposes to rely on ''effective scope'' to satisfy Characteristic 2 must demonstrate that the arrangement it proposes to eliminate the effect of seams is the practical equivalent of eliminating the seams by forming a larger RTO.

Factors for Evaluating Boundaries. In addition to the factors affecting the size of a region, other factors may affect the delineation of regional boundaries. As stated in the NOPR, the Commission proposed that RTO boundaries be drawn so as to facilitate and optimize the competitive, reliability, efficiency and other benefits that RTOs are intended to achieve, as well as to avoid unnecessary disruption to existing institutions. The Commission proposed in the NOPR a list of factors it would consider in evaluating the configuration for a proposed RTO. Nearly all of the comments agree that these factors are generally appropriate.

We recognize that different factors may suggest different configurations and that assessing the appropriateness of a region's configuration will require balancing factors and a flexible approach. Given this qualification, the Commission, in evaluating an RTO's boundaries, will consider the extent to which the proposed boundaries:

Facilitate performing essential RTO functions and achieving RTO goals: The regions should be configured so that an RTO operating therein can ensure non-discrimination and enhance efficiency in the provision of transmission and ancillary services, maintain and enhance reliability, encourage competitive energy markets, promote overall operating efficiency, and facilitate efficient expansion of the transmission grid. For example, we understand that there have been instances where transmission system reliability was jeopardized due to the lack of adequate real-time communication between separate transmission operators in times of system emergencies. To the extent possible, RTO boundaries should encompass areas for which real-time communication is critical, and unified operation is preferred.

Encompass one contiguous geographic area: The competitive, efficiency, reliability, and other benefits of RTOs can be best achieved if there is one transmission operator in a region. To be most effective, that operator should have control over all transmission facilities within a large geographic area, including the transmission facilities of non-public utility entities. This consideration could preclude a noncontiguous region, or a region with ''holes.'' However, as we discuss below, we will not automatically deny RTO status where the RTO is not able to obtain full participation in its region.

Encompass a highly interconnected portion of the grid: To promote reliability and efficiency, portions of the transmission grid that are highly integrated and interdependent should not be divided into separate RTOs. One RTO operating the integrated facilities can better manage the grid. This is not to say, however, that every weak interconnection belongs on a regional boundary. Where a weak interface is frequently constrained and acts as a barrier to trade, it may be appropriate to place that interface within an RTO region. It may be more difficult to expand a weak interface on the boundary between two regions; this may act as a barrier to trade between the two regions.[369]

Deter the exercise of market power: While the industry should work toward a goal of virtually seamless trade between RTOs, it may be that initially a significant amount of trade may be contained within an RTO, especially if the RTO or the market establishes a power exchange that covers the same area as the RTO. Thus, to have a competitive market, it is important to create an RTO region that is not dominated by a few buyers or sellers of energy. Also, the RTO configuration should not be one where the RTO participants can exercise transmission market power by collecting congestion fees on a critical corridor.

Recognize trading patterns: Given that a goal of this initiative is to promote competition in electricity markets, regions should be configured so as to recognize trading patterns, and be capable of supporting trade over a large area, and not perpetuate unnecessary barriers between energy buyers and sellers. There may exist today some infrastructure or institutional barriers unnecessarily inhibiting trade between regions that could be economically reduced. RTO boundaries should not perpetuate these unnecessary and uneconomic barriers.

Take into account existing regional boundaries (e.g., NERC regions) to the extent consistent with the Commission's goals for RTOs: An RTO's configuration should, to the extent possible, not disrupt existing useful institutions. The Commission recognizes that utilities have been working together regionally in different contexts for some time, and that there is value in preserving historical institutions and relationships; but we also recognize that in the evolving market, efficiencies may call for new configurations.

Encompass existing regional transmission entities: Because existing ISOs, and any other regional transmission entities we may hereafter approve, already integrate transmission systems, it may not be efficient to divide them into different regions. This is not to say, however, that RTO boundaries must coincide with existing regional transmission entities. An appropriate region may well be larger, and there may be circumstances that support combining or reconfiguring existing entities.

Encompass existing control areas: Many existing control areas are relatively small. It may be advisable not to divide them further. However, parties would not be precluded from proposing to divide a control area if they show this to be beneficial.

Take into account international boundaries: The Commission recognizes that natural transmission boundaries do not necessarily coincide with international boundaries. Indeed, a large part of Canada's transmission system, and a small part of Mexico's transmission grid, is interconnected on a synchronous basis with that of the U.S. Accordingly, an appropriate region need not stop at the international boundary. However, this Commission

[369] Commenters are also divided on whether weak interfaces should be encompassed within an RTO or act as a natural boundary. After consideration, we conclude that there is not a universal answer applicable to all situations. Consequently, we will address this issue as it arises in RTO proposals on a case-by-case basis.

does not have, and is not intending by this rule to seek, jurisdiction over the facilities in a foreign country. We will ask our international neighbors to participate in discussion of these issues. Perhaps what may be thought of as a ''dotted line'' boundary at the international border could be used to indicate that a natural transmission region does not necessarily stop at the border, while this Commission's jurisdiction does.

Although most commenters generally support these factors, other considerations are proposed as factors. For example, some commenters claim that we should make reliability and system security the dominant factor, while other commenters propose that we make trading patterns and market transactions the dominant factor. After consideration, we do not think it appropriate to identify one factor as the most important. Although it is essential that reliability not be jeopardized by RTO formation, and it is important to promote competition, we do not believe that one goal needs to be sacrificed to achieve the other.

Other commenters suggest additional factors that they deemed important to RTO boundaries, including, for example, established security coordinators, joint ownership arrangements, and Federal power marketing administration project marketing areas. We do not intend the factors we have listed to be exclusive: other factors may have merit for a particular region. We encourage parties to identify additional factors they believe relevant as we consider specific RTO proposals.

c. Control of Facilities Within a Region. We proposed in the NOPR to accept as RTOs only those proposals for which a region of appropriate scope and configuration is identified and the proponents represent a large majority of the transmission facilities within the identified region. We solicited comments on how best to balance our goal of having RTOs in place that operate all transmission facilities within an appropriately sized and configured region against the reality that there may be difficulties in obtaining 100-percent participation in all regions in the near term. We asked if we should deny RTO status for any proposal that does not include all transmission facilities within an appropriate region, or if we should require that the RTO at least negotiate certain agreements with any non-participants within its region to ensure maximum coordination.

Comments. Almost all commenters argue that RTO status should not be withheld if the RTO participants are unable to obtain participation by all transmission owners in the region.[370] Several commenters, such as Desert STAR and Minnesota Power, note that, if the Commission does not mandate 100 percent participation, it does not make sense to make it a condition of RTO approval. Other commenters propose standards to consider in determining when a proposed RTO represents sufficient facilities in the region. For example, Desert STAR suggests that the RTO have more than a majority of transmission owners and has not restricted membership. Southern Company proposes a standard that sufficient facilities include most of the major transmission facilities and the RTO can show benefits. MidAmerican proposes that the RTO be able to demonstrate that it would improve the wholesale market of any subregion of the country without hindering the wholesale market of any other region of the country. Enron/APX/Coral Power argues that an RTO should be approved if it provides an improvement even with ''gaps.'' Midwest Municipals believe that an RTO should be accepted if the Commission can make the judgment that the proposal with ''gaps'' is likely to encourage others to join through the strength of its operations and the facilities support the development of a competitive generation market. CRC suggests a standard that the proponents make a showing that they have diligently tried to accommodate the concerns and needs of the nonparticipating transmission owners.

Some commenters, such as NJBUS and Cal ISO, believe that an RTO should include the participation of all jurisdictional transmission owners in the region. Duke, however, opposes any attempt by the Commission to determine the appropriate level of participation, stating that the market should determine the participation level. Some commenters, such as Metropolitan, support having the RTO develop coordinated operations agreements with non-participants, while other commenters, such as Avista and Duke, caution that requiring such agreements would be contrary to market principles and would give the non-participating party too much bargaining power.

Seattle contends that the Commission should guard against utilities that would add to the RTO some facilities that are not necessary for RTO operations merely to obtain incentives. It argues that small municipal control areas should have some latitude to determine which of their facilities are regional for RTO purposes. Seattle also questions what ''participation'' entails for a utility that has limited transmission facilities.

Commission Conclusion. To satisfy the scope and configuration characteristic of this Final Rule, all or most of the transmission facilities in a region must be included in the RTO. Any RTO proposal filed with us should intend to operate all transmission facilities within its proposed region.

We recognize, however, that the proponents of an RTO may not be able to obtain agreement by all transmission owners in a region of appropriate scope and configuration to transfer operating control of their facilities to the RTO. This may occur, for example, because certain facilities may be owned by governmental entities that have restrictions on transfer of control that may require time to resolve. We do not believe that it would be desirable to deny RTO status or delay RTO start-up where the transmission owners representing a large majority of the facilities within a region are ready to move forward, while a few others are not. On the other hand, we do not believe it would be desirable to approve an RTO proposal for a region if the proponents represent only a small portion of the facilities in an otherwise satisfactory region.

Not knowing the full extent of difficulties that may be involved to achieve participation by all transmission facilities, we will not decide generically to automatically deny RTO status for lack of full participation. If an RTO proposal does not cover all the transmission facilities within its proposed region, it should identify the reasons for this, any continuing efforts to include all facilities, and any interim arrangements with the non-represented facility owners to coordinate transmission functions within the region. The Commission may at a future time determine whether the use of its authorities under FPA sections 202(a) and 206 is appropriate to rationalize proposed regions in order to accomplish the objectives of those sections, as discussed elsewhere in this Final Rule.

3. Operational Authority (Characteristic 3)

In the NOPR, the Commission proposed that the RTO have operational authority for all transmission facilities under its control.[371] We stated that this

[370] *See, e.g.,* Desert STAR, Southern Company, Metropolitan, MidAmerican, Nevada Commission, Avista, Enron/APX/Coral Power, Duke, PJM/NEPOOL Customers, Cal ISO, Midwest Municipals, CRC, NPRB, Minnesota Power, Tri-State, TVA.

[371] FERC Stats. & Regs. ¶ 32,541 at 33,734 and proposed § 35.34(i)(3). In the NOPR, we used the terms ''operational authority'' and ''operational

requirement raised two questions: Which functions must an RTO perform? How should an RTO perform the functions that it has reserved for itself? With respect to the question of which functions an RTO should perform, the Commission proposed that, at a minimum, the RTO must have operational authority over all transmission facilities transferred to the RTO and must be the security coordinator for its region.[372] As security coordinator, the RTO would be responsible for real-time monitoring of system conditions (including voltage, frequency, transmission and generation availability, and power flows) in order to anticipate potential reliability problems, and for directing and coordinating relief procedures to respond to transmission loading problems (such as assisting the control area in alleviating the loading, halting additional interchange transactions, reallocating the use of the transmission system, selecting the transmission loading relief procedure, and implementing emergency procedures, including directing that the control area immediately redispatch generation, reconfigure transmission or reduce load). Those proposing an RTO may also decide to have their RTO perform other traditional control area functions (such as maintaining the energy balance, interchange schedules and system frequency). The Commission proposed, however, that an RTO would not be required to be a single control area because of concerns over potentially high costs and technical limitations. Instead those proposing an RTO would be given flexibility in determining the best division of functions between the RTO and any providers of other control area functions if there are no other grid operators in its region. However, the Commission insisted that an RTO must be ultimately responsible for providing reliable and non-discriminatory transmission service.[373]

With respect to the second question of how an RTO will perform its functions, the Commission proposed that an RTO be given considerable flexibility in determining whether it will control facilities directly, delegate functions, or use a combination of these methods.[374] For example, we stated that an RTO proposal could have the RTO operate a single control area, or establish a master-satellite hierarchical control structure with one central and multiple distributed control centers (in either case it could propose to lease equipment and convert employees from existing control centers).[375] The Commission also proposed that the RTO must submit a public report assessing its operational arrangements no later than two years after it begins operations.[376]

Comments. Comments on the Functions an RTO Must Perform. Most commenters agree that the RTO must have operational authority[377] for the transmission facilities under its control.[378] Some commenters claim that this authority is necessary to prevent anticompetitive behavior by transmission owners.[379] Some commenters further contend that this authority must extend to all facilities involved in wholesale transactions so that the transmission owner does not retain control of ''access ramps'' that happen to be at low (34kV or 69kV) voltage levels.[380] In contrast, some utilities express concern that RTO authority over low voltage facilities will unnecessarily complicate operations.[381]

Several commenters oppose operational authority over the transmission system by the RTO. Some commenters claim that the Commission does not have the legal authority to require transmission owners to transfer control to any other entity.[382] Midwest Energy and SPP believe a transfer of authority would be too costly to implement. Other commenters maintain that the owner and operator of the transmission system must be the same entity in order to avoid liability disputes.[383] Mass Companies suggests that transmission owners retain authority to ensure the safe and prudent management of their facilities. ComEd suggests that transmission owners retain operational authority with the RTO having oversight responsibility.

Commenters are divided whether the RTO should be required to be a control area operator. The existing ISOs in California, New England and PJM, which are all control area operators, report that this structure is working in their regions. Some commenters express concern over potential harm to competitive markets if control area authority is not transferred to an independent entity.[384] ICUA recommends that the RTO be the sole control area operator. Many other commenters support a single control area as the ultimate goal, but suggest that the RTO be allowed to evolve to this structure and not be required to consolidate control areas immediately.[385] Other commenters express concern about potential costs associated with control area consolidation, but agree that such action would be acceptable if and when the RTO decides it is necessary for reliability or other reasons.[386]

Commenters that oppose requiring control area consolidation provide a variety of reasons.[387] Enron/APX/Coral Power state that only an RTO that is a transco should perform control area functions. The Florida Commission is concerned that control area consolidation may result in a security risk. Tri-State and WEPCO believe that there are higher priorities in RTO development (such as eliminating pancaking, and promoting regional system planning) and that emphasizing control area consolidation may inhibit RTO formation.

With respect to specific control area functions, numerous commenters discuss the need for an RTO to have some control of generation in order to ensure system reliability, especially

responsibility'' interchangeably. For purposes of clarity and consistency, we will use only the term ''operational authority'' to describe this function and have revised the proposed regulatory text accordingly.

[372] FERC Stats. & Regs. ¶ 32,541 at 33,734 and proposed § 35.34(i)(3)(ii).

[373] *Id.*

[374] *Id.* and proposed § 35.34(i)(3)(i).

[375] *Id.*

[376] *Id.* at 33,735.

[377] Operational authority refers to the authority to control transmission facilities, either directly or through contractual agreements with the entities that do have direct control. In contrast, security coordination refers to real-time monitoring of system conditions in order to anticipate potential reliability problems, and directing and coordinating relief procedures to respond to transmission loading problems.

[378] *See, e.g.,* APPA, Cal ISO, Duke, East Texas Cooperatives, Entergy, EPSA, First Rochdale, Georgia Transmission, Illinois Commission, IMEA, ISO–NE, Michigan Commission, Minnesota Power, Montana-Dakota, NASUCA, NECPUC, Nevada Commission, Mid-Atlantic Commissions, PacifiCorp, PJM, PJM/NEPOOL Customers, SNWA, Southern Company, SRP, SPRA, Tri-State, UtiliCorp, WPSC.

[379] *See, e.g.,* Illinois Commission, IMEA, NASUCA, PJM/NEPOOL Customers.

[380] *See, e.g.,* First Rochdale, IMEA, UMPA.

[381] *See, e.g.,* Montana-Dakota, Tacoma Power.

[382] *See, e.g.,* Florida Commission, Puget. It appears that the Florida Commission interprets a transfer of operational control as a transfer of retail dispatch authority. Although other commenters such as WPSC support the RTO having operational authority, they believe that the Commission may need legislative action to obtain the authority to require such a transfer.

[383] *See, e.g.,* Florida Power Corp., Georgia Transmission, JEA, MidAmerican, Southern Company, Enron/APX/Coral Power.

[384] *See, e.g.,* APPA, APS, Arkansas Consumers, NASUCA, NJBUS, TDU Systems.

[385] *See, e.g.,* Conlon, Illinois Commission, Los Angeles, First Energy, Minnesota Power, SRP, TDU Systems.

[386] *See, e.g.,* CP&L, ECAR, EEI, Entergy, EPSA, Southern Company.

[387] It appears that the Florida Commission and JEA believe that such a transfer would involve RTO control of retail dispatch. It also appears that Dynegy believes that the basic control area function of frequency control is identical to dynamic scheduling, which they believe should not be centralized or consolidated.

during emergency situations.[388] Minnesota Power suggests that the Commission include ''control generation as required to ensure reliability'' as an additional minimum function in the final rule. It also recommends that responsibility for area control error (ACE) and automatic generation control (AGC) be transferred to the RTO as control area functions because separating these functions from transmission operations can lead to reliability problems. Other commenters request that the balancing function be transferred to the RTO to prevent discriminatory behavior by transmission owners.[389]

There is widespread agreement among commenters that the RTO must be the security coordinator. Marketers, utilities, existing ISOs and customers all agree that coordination and reliability will be enhanced if a regional organization is responsible for maintaining grid security.[390] Some commenters state that the authority of a security coordinator to receive commercially sensitive information to order the curtailment of transactions and the shedding of firm load also grants it the ability to favor its own merchant functions. Confidence in comparable and non-discriminatory transmission service, therefore, will be improved if these functions are performed by an entity that is independent of all market participants.[391] Though essentially in support of our proposal, NERC and MidAmerican assert that is not necessary to link each RTO to a single security center, but rather it is possible to allow a single security coordinator to assume responsibility for more than one RTO. NERC points out that if an RTO performs all the characteristics and functions specified in the NOPR, it will necessarily be a security coordinator.

A number of parties state that the RTO must have access to real-time system information in order to perform its functions as security coordinator.[392] Montana-Dakota explains further that security centers, by definition, will be equipped with the hardware and software required to assume basic operational control of the system, which are beyond that required strictly for security functions.

Only two commenters express concern over the need for the RTO to be the security coordinator. ComEd, though supporting some security functions for the RTO, asserts that the RTO's role can be limited simply to one of oversight. ComEd does not believe that the RTO needs access to real-time data, and instead would allow the individual control areas to perform the bulk of the security functions. The only commenter that argues against making the RTO a security coordinator is Avista, which states that the security coordinator in the Pacific Northwest is already an independent body and has the authority necessary for ensuring reliability; therefore, no changes are required.

Comments on How an RTO Should Perform Its Functions. Overall, commenters strongly agree with the Commission's proposal to permit those proposing an RTO the authority to decide the type of control they require: direct, functional or a combination. Some commenters believe direct control is the best approach to prevent abuse of sensitive information and better ensure reliability.[393] However, Manitoba Board and Canada DNR express concern that continued coordination between U.S. and Canadian utilities might be undermined if highly centralized systems are developed and controlled by U.S. entities. A few commenters contend that it is best for the RTO to delegate control authority.[394] The majority of commenters support some form of hierarchical control structure, where the RTO would establish a master control center and direct the operations in the existing geographically distributed control centers, which would become satellite centers.[395] PJM and ISO–NE indicate that they both currently operate with a hierarchical control structure, where the ISO control center is the master control room that directs the actions of the satellite control centers.

A number of supporters of the hierarchical structure specifically request that the Commission ensure that the RTO has the authority to direct all actions at the satellite control centers and that the satellite centers will be independent in order to prevent discriminatory transmission service and the transfer of commercially valuable information to market participants.[396] Montana-Dakota and Otter Tail believe a major benefit of the hierarchical structure is improved emergency response and system security in a large region if the RTO is coordinating and directing the actions of all operators in the region. Finally, Enron/APX/Coral Power believe the standardization of balancing practices for a large region is an important benefit of a hierarchical system.

Commission Conclusion. Which Functions Must an RTO Perform? We reaffirm the determination proposed in the NOPR that an RTO must have operational authority for all transmission facilities under its control and also must be the security coordinator for its region. We recognize that it is difficult to draw a precise line between transmission control and generation control,[397] and we also recognize that given the changing nature of the industry, terminology such as ''control area operator'' is undergoing definitional changes.[398] Accordingly, it is difficult to state precisely what functions an RTO must have in order to have full operational authority for transmission facilities. Moreover, our desire to allow RTOs flexibility dissuades us from trying to be too precise. However, certain concepts are basic and generally understood in the industry.

[388] *See, e.g.,* NASUCA, First Energy, Otter Tail, PJM, PJM/NEPOOL Customers, Professor Hogan, Project Groups, SPRA, UtiliCorp, Williams, WPPI. We also discuss below in more detail the issue of congestion management as an RTO minimum function.

[389] *See, e.g.,* East Texas Cooperatives, WPPI, Project Groups.

[390] *See, e.g.,* Allegheny, APPA, APX, Cal ISO, ComEd, Dynegy, East Texas Cooperatives, Enron/APX/Coral Power, Entergy, EPSA, LG&E, Mass Companies, MidAmerican, Midwest Energy, Montana-Dakota, NASUCA, NECPUC, NERC, NJBUS, PJM/NEPOOL Customers, PPC, Professor Hogan, Seattle, South Carolina Authority, SPP, SRP, Tri-State, UtiliCorp, Williams.

[391] *See, e.g.,* LG&E, PJM/NEPOOL Customers, SPP, UtiliCorp. *See also supra* section III.D.1 for a more detailed discussion of independence as an RTO minimum characteristic.

[392] *See, e.g.,* Montana-Dakota, PJM/NEPOOL Customers, South Carolina Authority, Williams.

[393] *See, e.g.,* East Texas Cooperatives, First Rochdale, Illinois Commission, PJM/NEPOOL Customers.

[394] *See, e.g.,* MidAmerican, Seattle, South Carolina Authority.

[395] *See, e.g.,* ECAR, Enron/APX/Coral Power, EPSA, East Texas Cooperatives, First Rochdale, Industrial Consumers, ISO–NE, LG&E, Los Angeles, Lincoln, MidAmerican, Montana-Dakota, NECPUC, NASUCA, Otter Tail, PJM, PJM/NEPOOL Customers, Project Groups, Seattle, South Carolina Authority, Tri-State. Many of these commenters support eventual consolidation when any cost and technical barriers are overcome and if the RTO decides it is necessary.

[396] *See, e.g.,* EAL, East Texas Cooperatives, ISO–NE, Industrial Consumers, LG&E, NASUCA, PJM, PJM/NEPOOL Customers, Powerex, Project Groups, Tri-State.

[397] *See* NERC Operating Manual Policy 2 which can be found at www.nerc.com. As we have stated before, the dividing line ''between transmission control and generation control is not always clear because both sets of functions are ultimately required for reliable operation of the overall system.'' *Midwest ISO,* 84 FERC at 62,151. The idea that the entity that controls the transmission system must have some degree of control over some generation seems to be generally recognized. *See* Docket No. ER98–1438–000 Applicants' Response at 3.

[398] We note that the definition of a control area, and consequently the functions that must be performed by a control area, is currently being reexamined by the NERC Control Area Criteria Task Force in an open forum. *See* NERC web page at www.nerc.com.

One necessary aspect of operational authority as used here refers to the authority to control transmission facilities. This includes, but is not limited to, switching transmission elements into and out of operation in the transmission system (*e.g.,* transmission lines and transformers), monitoring and controlling real and reactive power flows, monitoring and controlling voltage levels, and scheduling and operating reactive resources. Functions such as these must be included within the operational authority of an RTO.

We conclude, as proposed in the NOPR, that the RTO is also required to be the NERC security coordinator for its region. The role of a security coordinator is to ensure reliability in real-time operations of the power system. As security coordinator, the RTO will assume responsibility for: (1) performing load-flow and stability studies to anticipate, identify and address security problems; (2) exchanging security information with local and regional entities; (3) monitoring real-time operating characteristics such as the availability of reserves, actual power flows, interchange schedules, system frequency and generation adequacy; and (4) directing actions to maintain reliability, including firm load shedding.

We believe that the RTO must be security coordinator for several reasons. The functions of the security coordinator are enhanced when they are performed over large regions. In addition, the independence of the security coordinator is important for ensuring non-discriminatory transmission service, and the RTO will have that independence. As we stated in *Midwest ISO:*

> This role [the role of a security coordinator] is central to maintaining grid reliability and non-discriminatory access. Under proposed NERC policies, security coordinators would be required to anticipate problems that could jeopardize the reliability of the interconnected grid. In the course of performing these reliability functions, the Security Coordinator would receive considerable information which is commercially sensitive. Therefore, it is important that the proposed Midwest ISO Security Coordinator be performed by an entity that is independent of market participants.[399]

However, we will allow flexibility in how the RTO performs its security coordinator functions. For example, an RTO may contract these responsibilities out to an independent security coordinator if this is justified. Also, this requirement does not prevent more than one RTO from sharing a single security coordinator as suggested by NERC.

As proposed in the NOPR, we will not at this time require the RTO to operate what traditionally has been thought of as a single control area for its region. However, the RTO must perform the control functions required to satisfy the minimum characteristics and functions in this Final Rule, including the transmission control and security coordinator functions discussed above,[400] in a non-discriminatory manner for all market participants.[401] We will permit those developing an RTO proposal flexibility in deciding on the particular division of operational responsibilities with existing control areas.

We recognize that the feasibility of consolidating existing control areas into a single such area may be limited by cost and technical considerations. However, we note that physical consolidation may be unnecessary when a hierarchical control structure is used to define a single control area by making existing control areas subject to RTO direction (and so avoiding the high costs and technical uncertainty associated with centralization of physical control for a very large RTO region). Hierarchical control is a form of power system control that relies on a master-satellite control structure, which establishes a single controlling authority without requiring the construction of a single, consolidated control room. Existing control centers are not replaced, but continue to operate, independent from market participants, as satellite control centers reporting to the RTO master control center. The RTO security center assumes the dual role of the master control center and security center, with clear authority to direct all actions at the satellite centers.[402]

We conclude that each region should be free to decide if and when the region will transition to a hierarchical control structure, consolidate the control areas in its region, or adopt a different control structure that best meets the region's needs.

How Should the RTO Perform Its Functions? We conclude that those designing the RTO should have flexibility to decide how it would exercise its operational control authority. The RTO operate the transmission system through direct physical operation by RTO employees, contractual agreements with other entities (*e.g.,* transmission owners and control area operators) or implement a hierarchical control structure involving a combination of direct and functional control. Under these arrangements, the personnel of existing control centers might become employees of the RTO or remain as employees of the control center owner, while being supervised by RTO personnel. We will leave it to the discretion of the region to decide on the combination of direct and functional control that works best for its circumstances.[403]

However, regardless of the method of control chosen, the RTO must have clear authority to direct all actions that affect the facilities under its control, including the decisions and actions taken at any satellite control centers. The system of operational control chosen must ensure reliable operation of the grid and non-discriminatory access to the grid by all market participants. In addition, to ensure that the RTO does not become locked into an operational system that is unsatisfactory, the Commission will require the RTO to prepare a public report that assesses the efficacy of its operational arrangements no later than two years after it begins operations.

4. Short-Term Reliability (Characteristic 4)

The fourth proposed characteristic of an RTO is that it must have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. In the NOPR we identified four basic short-term reliability responsibilities of an RTO: (1) the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules; (2) the RTO must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities; (3) when the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4)

[399] 84 FERC at 62,158.

[400] For example, several commenters state that an RTO must have some authority over generation to ensure system reliability. The RTO is required to have some authority as a minimum characteristic, as discussed with respect to short-term reliability.

[401] In our order approving the Midwest ISO, we stated that our approval of the ISO was based on the applicants' commitment that the ISO would be able to ''take *all* actions necessary to provide nondiscriminatory transmission service, promote and maintain reliability.'' *Midwest ISO,* 84 FERC at 62,159.

[402] *See, e.g.,* Marija Ilic and Shell Liu, *Hierarchical Power System Control: Its Value in a Changing Industry,* Springer-Verlag, 1996.

[403] This issue is also addressed in greater detail in our discussion of the RTO's role as a provider of ancillary services as an RTO minimum function.

if the RTO operates under reliability standards established by another entity (*e.g.,* a regional reliability council), the RTO must report to the Commission if these standards hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service.[404]

Comments. General Comments. Commenters address both general concerns about reliability as well as the four basic proposed short-term reliability responsibilities of an RTO. Most commenters generally agree that the RTO should have the responsibility for short term-reliability.[405] Several commenters raise questions regarding definition and scope of ''short-term'' reliability. TEP requests that the Commission further define the time period involved. It suggests that designating a specific time period (whether one month, six months or a year) would be beneficial to evaluating this characteristic. Enron/APX/Coral Power requests that the Commission make clear that ''short-term'' is intended to mean ''real-time.''

While agreeing that the RTO should be given ultimate control over facilities necessary to preserve reliability, SMUD expresses concern that the RTO should not be encumbered with responsibility for facilities that do not serve a regional transmission function. TANC requests that the RTO's responsibility over reliability not infringe on the management responsibilities of local regulatory authorities or interfere with the management and operation of the local system facilities of a utility distribution company.

PG&E requests that the Commission require that the RTO rely primarily on market mechanisms to maintain reliability. However, PJM/NEPOOL Customers urge the Commission to ensure that the RTO's actions in maintaining the short-term reliability of the grid do not unreasonably impinge on the freedom of business decisions inherent in a competitive supply market. Several commenters, such as San Francisco and Minnesota Commission, state that because the primary function of a RTO is ensuring short-term reliability, it should be more clearly defined and should not be compromised by any other RTO market functions.

PJM suggests that the Commission grant additional authorities to the RTO to ensure reliability, including the authority to (1) collect information, (2) direct operations in the control area, (3) assure that those it directs will respond in a predictable manner (which the RTO can achieve through training and drills) and (4) declare an emergency, direct emergency operations, and determine when emergency conditions have ended.

Southern Company notes that the industry has little, if any, experience in granting a new entity control over the operations of a transmission system that encompasses a broad, multi-state region.[406] It claims that transmission owners and State commissions must be assured that the RTO is capable of operating a regional transmission system reliably before an RTO is formed. New York Commission indicates that the authority of States to require the maintenance of electric system reliability should be recognized in establishing responsibilities. Iowa Board believes that there is a need for greater regional development of reliability standards to reflect regional needs and conditions. It requests that State commissions be involved in the decisionmaking process of an RTO to ensure that electric facilities are properly sized and located and that additions are not detrimental to the reliability of the grid.

Comments on Interchange Scheduling. The Commission proposed that, in the context of the RTO's role as the recipient and evaluator of all requests for transmission service under its own FERC-approved tariff, an RTO that is a control area operator must also receive, confirm, and implement all interchange schedules between adjacent control areas.[407] The Commission expressed concern that non-RTO control area operators would receive commercially sensitive information involving its competitors in implementing interchange schedules and questioned whether there is any Commission action, other than its current code of conduct standards, and short of requiring consolidation of all control areas within a region, which could address this concern.

Several commenters agree that the RTO should have authority over receiving, confirming and implementing all interchange schedules.[408] PJM believes that an independent ISO is in the best position to exercise the scheduling authority of an RTO. It suggests that an RTO that is independent of commercial interests in the market does not face the commercial information problem because it does not compete with market participants and consequently would make scheduling decisions in an unbiased and fair manner.

PJM/NEPOOL Customers claims that interchange scheduling oversight must be performed by an independent entity because it would be neither possible nor desirable for a non-RTO control area operator to perform this function without access to commercially sensitive information. It suggests that the RTO maintain direct control over interchange scheduling either by using RTO employees or a master satellite arrangement where ultimate responsibility remains in the RTO master control area operating room. APX suggests that requiring a contractor (acceptable to the RTO and the control area operator) to operate the control area operator facility could help address this concern.

Enron/APX/Coral Power believes that the risk is eliminated if transmission operations, including control-area operations, are operationally separated from the load and generation of vertically-integrated utilities. Barring such complete separation, this risk could nevertheless be substantially obviated if the RTO provided control area operators with information only about scheduled net interchanges between control areas without disclosing the individual transactions making up the new schedules.[409]

However, other commenters contend that control area operators will continue to need information on individual transactions in order to implement interchange schedules and to ensure real-time reliability.[410] Desert STAR believes that work should be done in this area to determine what information is required by control area operators and when they must receive it in order to carry out their reliability responsibilities.

Florida Commission states that this issue has already been resolved within the Florida Reliability Coordinating Council (FRCC) by requiring all entities who operate control areas within the

[404] FERC Stats. and Regs. ¶ 32,541 at 33,735.

[405] *See, e.g.,* American Forest, Cal ISO, California Board, Cinergy, CMUA, CSU, EAL, Enron/APX/Coral Power, Entergy, EPSA, Industrial Customers, NASUCA, NECPUC, PJM, PNGC, SMUD, UtiliCorp, H.Q. Energy Services, Mass Companies, Mid-Atlantic Commissions, MidWest Energy, Minnesota Commission, NY ISO, PacifiCorp, PG&E, Williams, WPSC.

[406] Southern Company notes that the California and ERCOT ISOs operate within the boundaries of a single state. In PJM, New York and New England, the control of the grid remains remarkably unchanged because the ISOs in those regions were already operating the system on behalf of the transmission owners and adopted the institutions and infrastructures of an ISO.

[407] FERC Stats. & Regs. ¶ 32,541 at 33,735–36.

[408] *See, e.g.,* Cal ISO, CMUA, Entergy, Mass Companies, NECPUC, Nevada Commission, PJM/NEPOOL Customers, PJM, SMUD, Southern Company, WPSC, PG&E.

[409] *See also* Southern Company.

[410] *See, e.g.,* Duke, Florida Power Corp.

region that require access to commercially sensitive information to sign agreements that separate reliability personnel and the relevant information from their wholesale merchant personnel.

Several commenters, such as Duke and Florida Power Corp., state that no additional Commission action is necessary. These commenters believe that the existing code of conduct standards are working and the reciprocity provisions of Order No. 888 provide for compliance with the code of conduct standards by all non-public utility control area operators. Florida Power Corp. also notes that within the FRCC, all entities operating control areas are required to sign agreements verifying functional separation.

Comments on Generation Redispatch. In the NOPR, the Commission proposed that the RTO's reliability authority include the ability to order redispatch of any generator connected to the transmission grid when necessary for the reliability of the grid. However, the RTO would have no authority over initial unit commitment and normal dispatch decisions.[411]

Several commenters agree that the RTO have some authority to order redispatch when necessary to maintain the reliability of the grid.[412] Sithe, however, believes that, in the evolving competitive marketplace, redispatch authority alone is insufficient. It argues that the RTO should also provide appropriate incentives to the owners of assets that are needed for reliability to maintain those assets and make them available for operation in constrained areas. Sithe urges the Commission to consider adopting a final rule that provides RTOs with sufficient commercial authority, ''including the necessary financial resources'' to enter into market-rate business arrangements, that assure availability of assets needed for reliability. Sithe states that without this authority, the RTO may not have sufficient tools to fully ensure reliability, because must-run generators would have little incentive to continue to operate in constrained areas.

CMUA maintains that it is insufficient to vest authority in the RTO to maintain short-term reliability without also vesting enforcement powers to ensure compliance with RTO dispatch instructions. Allegheny and other commenters agree that RTOs should be able to direct redispatch, particularly if the redispatch is accomplished under a market-based compensation scheme as a part of transmission service pricing methodology that uses the redispatch costs to set marginal system use costs. However, they argue that in no case should the RTO be able to direct generation redispatch unless the generator is compensated at market value (unless market power issues are involved).[413]

Avista expresses serious concern with the breadth of a redispatch requirement. It believes that the right to order redispatch of generation should be negotiated among the parties in the region without a presumption that the RTO must have broad redispatch authority, except in emergency circumstances. Avista and others note that a negotiated approach is particularly important to operators of hydroelectric resources which are subject to numerous environmental and operating restrictions that limit their ability to redispatch.[414] Avista and SMUD request that the Commission clarify that the RTO's authority to redispatch is limited to emergency circumstances affecting reliability.

Chelan believes that RTOs should be required to enter into arm's-length agreements with those generators that are willing to service redispatch requests, and compensate those generators for supplying this service. RTOs should not be allowed to unilaterally redispatch a generating unit without the generator's consent, and without compensation.

Commenters, such as Cal ISO and Nevada Commission, suggest that the Commission require reliability-related services (i.e. redispatch) be provided to RTOs under a set of uniform rates, terms and conditions. Such a requirement would reduce the Commission's administrative burden of contracts governed by different sets of terms and conditions.

EME believes that the RTO's control over dispatch of generation should be carefully circumscribed. It recommends that reliability functions be internalized into explicit procedures for congestion pricing. It states that in most cases proper pricing signals can provide sufficient incentives for generators to schedule operation of their facilities to ensure system reliability.

Industrial Consumers states that the RTO's redispatch decisions regarding ''any generator'' must be qualified to excuse on-site generators that serve an industrial load, especially those that serve a critical steam host. For environmental, safety and economic reasons, these units should not be forced to redispatch except as a last resort option.

Metropolitan supports an RTO having authority to order redispatch of any generating unit when necessary for the reliability of the grid. However, ''reliability'' must be carefully defined to avoid RTO interference with normal market operations by redispatching generation for its own convenience, or to alleviate adverse market conditions.[415]

Several commenters oppose the proposal to allow the RTO to redispatch generation.[416] PG&E believes that the proposal would give too much latitude to RTOs and create an incentive to impose centrally determined fixes on market operations, rather than allowing market mechanisms to self-correct. Therefore, PG&E argues that RTOs should be allowed to redispatch generation facilities only when there is a true reliability emergency as specified in the RTO tariff. Moreover, RTOs should be able to redispatch only those units that have actually participated in the market.

PJM/NEPOOL Customers believes that the authority as proposed in the NOPR is too broad and must be further defined. It requests that the Commission ensure that this authority is exercised only during only the most serious circumstances when grid reliability is truly in danger. It suggests that the Commission promulgate or pre-approve reliability standards for determining when the RTO can order redispatch of generators, the amount of generation assets that the RTO will have authority over and standards for the redispatch order. Southern Company recommends that the Commission provide only general guidance concerning redispatch and allow the regions to develop more specific procedures.

When considering allowing an RTO to redispatch a Federal hydroelectric generator, SPRA emphasizes that the Commission must recognize that individual Federal hydroelectric generators are under the control of either the Corps, the Bureau of

[411] FERC Stats. and Regs. ¶ 32,541 at 33,736.

[412] *See, e.g.,* Cal ISO, Cinergy, CMUA, NECPUC, PJM, UtiliCorp, Entergy, Allegheny, LG&E, Lincoln, Metropolitan, Minnesota Power, Nevada Commission, Otter Tail, Southern Company, TDU Systems, NASUCA, Reliant, Mass Companies, TAPS.

[413] *See, e.g.,* Cinergy, Chelan, Southern Company, LG&E, Reliant.

[414] *See, e.g.,* CMUA.

[415] Metropolitan believes the Cal ISO's definition of system emergency appropriately describes the circumstances in which redispatch may be appropriate. A ''system emergency'' is described as ''any abnormal system condition which requires *immediate* manual or automatic action to prevent loss of load, equipment damage or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria.''

[416] *See, e.g.,* PG&E, Southern Company, Reliant, SMUD.

Reclamation or the International Boundary Waters Commission, not the PMA. While a PMA may belong to an RTO, it is unlikely that other Federal agencies will. The Commission must give careful consideration to determine that RTO redispatch authority does not prohibit or limit a PMA's ability to fulfill its statutory obligations.

Comments on Transmission Maintenance Scheduling. In the NOPR, the Commission proposed that an RTO which operates transmission facilities owned by other entities be authorized to approve or disapprove all requests for scheduled outages of transmission facilities in order to ensure that maintenance outage schedules meet applicable reliability standards.[417]

The Commission requested comments on a number of issues related to this proposed requirement: Does it cede too much or too little authority to the RTO? If the RTO requires a transmission owner to reschedule its planned maintenance, should the transmission owner be compensated for any costs created by the required rescheduling? Would it be feasible to create a market mechanism to induce transmission owners to plan their maintenance so as to minimize reliability effects? Should an RTO that is an ISO have any authority to require rescheduling of maintenance if it anticipates that the planned maintenance schedule will adversely affect power markets? If the RTO is a transco, can it manipulate its transmission maintenance schedules in a manner that harms competition?

The Commission stated that the RTO's regional perspective will allow it to coordinate individual maintenance schedules with each other as well as with expected seasonal system demand variations. Because the RTO will have access to extensive information, it will see the ''big picture'' and be able to make more accurate assessments of the reliability effect of proposed maintenance schedules than individual, sub-regional transmission owners.

Commenters address essentially three issues related to transmission maintenance scheduling: the RTO's authority; appropriate compensation; and use of market mechanisms.

RTO Authority to Schedule Transmission Maintenance. Many commenters support giving an RTO authority over transmission maintenance scheduling.[418] Duke, however, believes that an enforcement mechanism may also be needed. First Rochdale recommends that transmission owners be given the right to protest an RTO's actions to the Commission. Reliant, however, opposes RTO authority over maintenance scheduling, arguing that transmission maintenance decisions must reside with transmission facility owners.

Seattle and NYPP suggest that the Commission define an RTO role only for scheduling facility outages that are clearly associated with the regional transmission network because internal subtransmission and radial transmission facilities do not have regional significance. Turlock supports restricting the RTO's authority to the grid it manages to prevent its outage scheduling authority extending beyond the grid for which it is responsible. On the other hand, TDU Systems claims that an RTO should also coordinate maintenance of interconnected distribution facilities that are not under its control, if maintenance on those facilities would adversely affect RTO operations.

Duke suggests that with the creation of an RTO that is not a transco, a set of governing principles for outage coordination should be established. The parties should agree on the timing of requests for planned maintenance and the timing of responses to those requests. If for any reason, other than the gross negligence of the transmission owner, a scheduled maintenance outage was determined to be a problem after an agreement is reached, rescheduling the outage would require the mutual consent of the transmission owner and the RTO.

EAL recommends that appropriate contracts with existing transmission facility owners that ensure the continued reliable operation of the grid are required. Principal elements of such contracts would include standards of service, provisions for information sharing and reporting, maintenance scheduling, transmission facility ratings, testing and performance expectations. Maintenance scheduling should include provisions for maintenance deferral under instructions from the RTO if required for system security reasons only.

NYPP states that arrangements for outages should be made well in advance of the outage start date because RTO approval of proposed schedules could become the critical path. If approval is delayed, or subsequently revoked, the transmission owner will incur significant expenses that should be reimbursed.

Montana-Dakota suggests that the effects of rescheduling can be decreased by having the RTO review and approve all transmission maintenance schedules on a weekly, monthly and quarterly basis. After reviewing the transfer capability and market effects of the proposed outage, the RTO should communicate the need to reschedule to the transmission owner far enough in advance of the planned outage to allow the owner to reschedule, possibly to avoid any cost impact. Montana-Dakota notes, however, that the closer the date of the outage, the higher the probability of an economic impact.

Southern Company requests that the Commission clarify that once an RTO approves a scheduled outage, it should be allowed to change that schedule only if implementing the plan would compromise system integrity or reliability.

Seattle believes that the NOPR fails to provide adequate assurances to transmission owners that a timely maintenance schedule will be adopted by the RTO. The RTO must establish timely dates certain for maintenance outage requests from operating entities. To do this the RTO must adequately balance safety considerations, and the cost of deferring maintenance with commercial impact. For these reasons, an RTO should not be permitted to arbitrarily postpone required maintenance.

Compensation. Nearly all of the commenters believe that transmission owners should be compensated in some form if they are required by an RTO to reschedule maintenance.[419] Avista argues that the transmission owners' shareholders should not bear the burden of decisions made by an independent body that result in reduced revenues or increased costs for the transmission owner.

Metropolitan states that if an RTO requests a transmission owner to reschedule planned maintenance for reliability concerns, a transmission owner should be compensated only for its direct costs necessarily and reasonably incurred in complying with the RTO's request. Direct costs may include, for example, increased labor or equipment expenses arising from the rescheduled maintenance. However, Metropolitan does not believe a transmission owner should recover lost

[417] FERC Stats. and Regs. ¶ 32,541 at 33,736–37.

[418] *See, e.g.*, Cal ISO, NECPUC, PJM, Desert STAR, Entergy, PGE, Allegheny, Avista, LG&E, Lincoln, Tri-State, WPSC, CRC, Duke, EAL, First Rochdale, Industrial Consumers, ISO–NE, Metropolitan, Montana-Dakota, NASUCA, New Smyrna Beach, NYPP, Oneok, PG&E, Southern Company, SRP, Turlock, WPPI, Florida Power Corp., Nevada Commission.

[419] *See, e.g.,* PJM, TANC, WPSC, Avista, Lincoln, CRC, Duke, Metropolitan, Minnesota Power, Montana-Dakota, NASUCA, NPRB, NYPP, PJM/NEPOOL Customers, Reliant, TDU Systems, Turlock, Florida Power Corp., Reliant, Desert STAR, Southern Company.

opportunity costs arising from the rescheduled maintenance because opportunity costs are uncertain and speculative.

Southern Company argues that, if an RTO requires a transmission owner to reschedule a previously approved outage, the RTO should compensate the transmission owner for any additional costs caused by the rescheduling.

NASUCA believes that the RTO should compensate transmission or generation owners only to the extent that incremental costs are incurred due to the rescheduling of outages. NASUCA argues that it is unlikely that owners would incur significant incremental costs, especially for transmission outages.

Some commenters such as PGE and Minnesota Power state that if an RTO requires a transmission owner to reschedule its planned maintenance for reliability reasons in an emergency situation, the RTO should not be required to compensate the transmission owner. However, if an RTO requires a transmission owner to reschedule its planned maintenance for economic reasons, the RTO should be required to compensate the transmission owner for liquidated damages.

Other commenters such as Tri-State and Cal ISO oppose transmission owners being compensated for the rescheduling of maintenance work. Cal ISO states that, where an RTO properly exercises such authority by requiring a transmission owner to reschedule a maintenance outage, that transmission owner is not entitled to compensation for the costs associated with rescheduling. Tri-State recommends factoring any additional expense into the revenue requirement that the transmission owner receives from the RTO.

Market Mechanisms. PJM/NEPOOL Customers suggests that the RTO enact a compensation mechanism in transmission outage rescheduling situations or propose to use a market mechanism to encourage transmission owners to plan maintenance so as to minimize reliability effects. Minnesota Power, however, argues that maintenance rescheduling to benefit power markets is analogous to generation redispatch and should be paid for by the benefitting market participants.

Montana-Dakota believes that an RTO should have the authority to reschedule maintenance for market effects if there is an incremental cost reimbursement mechanism in place that would provide an incentive to the transmission owner to change maintenance schedules to benefit the market.

Metropolitan argues that an RTO with authority to unilaterally reschedule transmission maintenance for market considerations could have a destabilizing effect on the power market. Emerging markets require predictability to thrive, and therefore RTOs should interfere in market operations only when necessary to address reliability concerns.

Florida Power Corp. suggests that, while it may be feasible to develop a market mechanism to induce transmission owners to plan their maintenance to minimize reliability effects, it would be far simpler to retain the existing structure in which a single entity both owns and operates the transmission system. When ownership and operation are combined, a single entity is responsible for both reliability and maintenance, and thus has a natural incentive to seek an optimal balance between these activities. Thus, Florida Power Corp. opposes RTOs having authority to reschedule maintenance to manage the performance of the market.

Turlock also does not believe an RTO should have authority to make transmission outage decisions based on market considerations. Turlock, as well as Desert STAR and CRC, believe instead that consideration should be given to motivating transmission owners to appropriately schedule their maintenance outages, to minimize impacts on competitive markets.

Comments Generation Maintenance Scheduling. The short-term reliability characteristic, as proposed in the NOPR, would *not* give an RTO authority over proposed generation maintenance outage schedules. However, the Commission noted that some generation control is necessary for reliable operation of a transmission system. The Commission asked whether an RTO should have some authority over generation maintenance schedules and, if so, how much.[420]

The majority of commenters support an RTO having at least some authority over generation maintenance schedules.[421] However, most commenters suggest limiting the RTO's authority. Some commenters suggest that an RTO have authority only for generating units that are ''must-run'' or that the RTO has under contract due to the requirement to maintain system reliability.[422] Desert STAR believes that an RTO should not attempt to manipulate the commercial power market when reliability is not affected.

Cinergy supports an RTO having the ability to request changes to a schedule to serve reliability needs, coordinate transmission outages, and maximize grid efficiency to increase ATC for transmission customers' use, so long as generators receive compensation at market-based prices for missed market opportunities. Other commenters agree that an RTO should compensate the generation owner if a schedule change is necessary.[423]

A few commenters claim that the RTO should not have any authority over generation maintenance schedules.[424] SPRA states that requiring such authority would discourage or prevent participation by PMAs because other Federal agencies own the hydroelectric plants that generate the power marketed by the PMAs.

Tri-State does not believe that an RTO should have approval authority over generation maintenance outages because these outages are driven by the cost considerations associated with generation plant equipment replacement or rehabilitation. However, Tri-State agrees that an RTO must have advance knowledge of the scheduled generation outages in order to assure transmission system reliability and adequacy of reserves. Other commenters concur with a notification requirement.[425] Cinergy notes, however, that while it believes a generator may be required to submit its maintenance schedule to an RTO, the RTO should be prohibited from sharing that information with any other market participants, or affiliates of market participants.

Comments on Performance Standards. In the NOPR, the Commission discussed the establishment of performance standards by an RTO for transmission facilities under its direct or contractual control.[426] For example, an RTO could establish a standard that identifies specific performance targets for planned and unplanned outages of facilities. The Commission requested comments on whether a non-profit ISO could establish incentive schemes for the transmission owners whose facilities it operates.

PJM believes that an RTO will be capable of developing performance

[420] FERC Stats. and Regs. ¶ 32,541 at 33,737.

[421] *See, e.g.,* Cinergy, NECPUC, PJM, Desert STAR, WPSC, Cal ISO, EAL, Industrial Consumers, ISO–NE, Turlock, Florida Power Corp., Metropolitan, Minnesota Power, Montana-Dakota, NASUCA, Nevada Commission, NYPP, PSNM, TDU Systems.

[422] *See, e.g.,* Desert STAR, Metropolitan, Turlock, Florida Power Corp., PSNM, NYPP.

[423] *See, e.g.,* WPSC, LG&E, Montana-Dakota.

[424] *See, e.g.,* Duke, PJM/NEPOOL Customers, SPRA, Tri-State, Empire District.

[425] *See, e.g.,* Enron/APX/Coral Power, FirstEnergy, Mass Companies, Metropolitan.

[426] FERC Stats. and Regs. ¶ 32,541 at 33,737.

standards and incentives to encourage transmission owners and generators to operate and maintain reliable facilities. It states that market participants cooperatively can create market-oriented incentives to maintain their transmission and generation facilities effectively.[427]

Duke also believes that incentive schemes can be developed. It suggests that the revenues collected from users by the RTO could be returned to transmission owners according to a prearranged formula that incorporates quality standards for reliability. Thus, the revenue allocation would reflect transmission owner performance in providing a reliable system.

PSE&G believes that RTOs will, and should, be able to offer incentives to participants to ensure that reliability standards are not only met but exceeded. It states that a mechanism of linking payment with performance, measured against accepted benchmarks, has worked well for many years in PJM.

EAL states that appropriate contracts with existing transmission facility owners that ensure the continued reliable operation of the grid are required. It suggests that these contracts include standards of service, provisions for information sharing and reporting, maintenance scheduling, transmission facility ratings, testing and performance expectations.

Industrial Consumers believes that an RTO could establish performance standards for transmission facilities that takes into account the ''reliability'' of each facility. It argues that a facility that has frequent unplanned outages should not receive the same compensation as a facility whose availability is more reliable. It suggests that a transmission owner be precluded from recovering fixed costs during periods of unplanned outages that exceed some minimum threshold based on superior performance.

Cal ISO indicates that its tariff provides for the implementation of maintenance standards, and penalties under those standards, to ensure both adequate maintenance and system reliability. These provisions act in concert with the California ISO's authority to coordinate and approve maintenance outages.

Southern Company believes that the establishment of performance standards for transmission facilities controlled by an RTO is misplaced. Transmission owners plan and operate their transmission systems according to NERC and regional reliability standards, as well as State legal and regulatory requirements. Thus, while Southern Company doesn't claim that performance-based incentives are inappropriate, it points out that there already are existing standards to ensure reliable system operations.

Comments on Facility Ratings and Operating Ranges. Reliable operation of the transmission system in the short-term requires both continuous monitoring of equipment availability and loading, and actions to maintain loading levels within the established operating ranges and equipment ratings. The NOPR suggested that RTOs are best situated to establish ratings and operating ranges for two reasons. First, they will have the most complete information about expected and real-time operating conditions. Second, RTOs will be trusted because they will not have any economic interests in electricity market outcomes and they will not be owned or controlled by any market participants. The Commission proposed to let RTO established equipment ratings prevail in a dispute with a transmission owner pending the outcome of a dispute resolution process.[428]

Nearly all commenters that address this issue oppose the NOPR proposal. South Carolina Authority urges the Commission to proceed with caution to prevent avoidable damage to persons or property. SRP argues that ratings and operating ranges influence the useful life and maintenance cost of equipment, as well as the level of service to the end-use customer, and notes that each transmission owner has a legitimate interest in the ratings. SRP believes that the ideal situation would be to establish ratings by mutual consent of the transmission owner and RTO. If they cannot agree, the issue should go to dispute resolution.

NYPP and Mass Companies oppose this proposal because transmission owners have the fiduciary responsibility to protect their assets. Furthermore, they state that the rating of equipment necessarily requires a particularized knowledge of the equipment and related facilities that is unlikely to be possessed by the RTO.

Metropolitan believes that a well-established reliability organization is best suited for establishing maximum transmission line ratings that can be sustained over most of the hours in a year because it will include the cooperation of technical groups representing all systems, not just those under RTO control. It sees no benefit from moving this responsibility to RTOs when the reliability councils have historically performed this function with a minimum of controversy. EAL suggests that since the owner of the transmission facility assumes the equipment, personnel and public risks for the operation of its equipment, the RTO could fulfill an audit role to ensure that facility ratings by the owners follow industry norms.

Seattle suggests that the Commission instruct RTOs to work cooperatively with facility owners, since ratings on most power transmission equipment are a function of age and past usage, and a new entity will not have such historical information.

Southern Company states that transmission owners have responsibilities to their shareholders and State commissions to operate their equipment safely and reliably. SPRA believes that this proposal has the potential to create significant liability risks for the United States.

Entergy believes that a transco has an advantage at performing this function because it will have the natural incentive to maintain the highest and safest ratings for the transmission facilities since it will be solely and directly responsible for the risks and rewards of equipment ratings.

Comments on Liability for Actions. Given that an RTO has responsibility for system reliability, the NOPR requested comments on the appropriate extent of an RTO's liability for its actions, and whether RTO facility ownership changes this determination.[429]

Most commenters believe that liability must be linked to the entity operating and controlling the transmission assets. Several commenters recommend that all RTO governing documents and operating agreements clearly establish the RTO's liability for any facilities that it operates but does not own.[430] SRP recommends that the Commission not set a hard and fast rule, but rather give deference to assignments of liability worked out between the RTO and the transmission owner in the course of negotiating an operating agreement.

Salomon Smith Barney believes that an RTO should be paid to run the network, and should suffer the consequences if it is not run well. Given this reasoning, it believes that an RTO requires sufficient capital to bear the risk, and that it operates under a regulatory scheme that acknowledges that higher risk taking requires a higher return.

Other commenters focus on how to apportion liability. Several commenters

[427] *See also* LG&E.

[428] FERC Stats. and Regs. ¶ 32,541 at 33,737–38.

[429] FERC Stats. and Regs. ¶ 32,541 at 33,738.

[430] *See, e.g.,* Seattle, PGE, Desert STAR, PSNM, South Carolina Authority.

suggest that the governing standard for liability for a particular activity should be the same standard that the Commission has approved for comparable ISO conduct. Thus, for example, the RTO would be subject to liability only on account of its reliability activities when damage caused by its actions is found to be the result of gross negligence or intentional misconduct.[431]

Other commenters believe that, if the RTO assumes authority to ensure proper maintenance and reliability of the system, it should assume that role fully (*i.e.,* assume liability for its decisions) and it should hold transmission owners harmless for any increased cost responsibility.[432]

Tri-State believes that an RTO should not be held liable for the inevitable errors and omissions that will occur during transmission system operations except in the instance of gross negligence. It believes that without some form of indemnification, the RTO could be the target of numerous lawsuits alleging financial harm as a result of RTO actions.

TANC believes that the RTO should be held liable for the consequential damages resulting from the RTO's instructions, if damage is caused to the transmission owners facilities as a result of the RTO requiring a transmission owner to operate its facilities in a manner that is inconsistent with prudent utility practice.

Comments on Reliability Standards. In the NOPR, the Commission expressed a potential concern regarding an RTO's implementation of reliability standards that are established by another entity. The Commission identified two specific concerns: (1) regional or sub-regional reliability groups may not be as independent from market participants as RTOs; and (2) almost every reliability standard will have a commercial consequence. The NOPR proposed to require an RTO to notify the Commission immediately if implementation of externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service.[433]

Most commenters generally support the proposal in the NOPR, although a few commenters believe that the NOPR proposal does not go far enough. On the other hand, some commenters seek clarification or oppose the NOPR proposal; most commenters that oppose the NOPR proposal believe that RTOs must be subordinate to national or regional reliability groups.

PJM/NEPOOL Customers and other commenters agree that the RTO is an appropriate institution to evaluate whether other rules and requirements are impacting its ability to perform its function and to inform the Commission of this fact.[434]

PSE&G requests that the Commission clarify in its Final Rule that RTOs, not reliability trade associations, will have primary responsibility for resolving reliability issues in the future. It suggests that reliability trade associations can continue to play a role in developing reliability standards to be incorporated into RTO tariffs; these standards would then be implemented by the RTOs and ultimately enforced by the FERC. The standards, however, must be developed through a fair and open consensus process, such as the American National Standards Institute (ANSI) process.

EPSA believes that reliability standards should be uniform throughout the United States. Reliability standards should be established at the national level through an industrywide representative organization, subject to review and approval by the Commission. Reliability rules should deviate regionally only if necessary to reflect specific operating conditions that are unique to a particular region. EPSA requests that existing reliability rules be considered carefully by the RTO, and reviewed by the Commission, as to their function and importance. EPSA and other commenters suggest that RTOs replace existing regional reliability councils as the entity responsible for maintaining compliance with nationally established reliability standards.[435]

Conlon claims that the RTO must have the ability to establish various reliability standards that every participant. He suggests that the RTO, or the Commission with delegated authority to the RTO, set mandatory standards and impose sanctions or fines for violations.

Cal ISO believes that RTOs are the appropriate entities to establish reliability standards. Regional organizations (not a single national standard-setter) should have the flexibility to develop standards that reflect regional priorities as well as individual issues related to particular areas or configurations in the transmission grid. It recommends that RTOs have the authority and responsibility to develop regional reliability standards, subject to general oversight by an appropriate independent national reliability organization such as NAERO.

Similarly, Entergy believes that the RTO should have the primary role, authority and responsibility to adopt, implement and enforce regional reliability standards. Entergy further argues that this authority must be subject to regional oversight, especially as to reliability issues between and among interconnected RTOs.

Some commenters argue that the Commission should provide additional authority to RTOs. For example, PJM believes that an RTO should have exclusive authority for administering the regional reliability of the bulk power system. It argues that no entity external to an RTO's region should have authority to dictate reliability rules that adversely affect the reliability in a region served by an RTO. Thus, PJM believes the Commission should extend this proposal beyond the proposed reporting requirement. In its opinion, RTOs that are responsible for a particular area of the bulk power market system best can develop tools that are designed to meet the needs of their individual areas. PJM requests that the Commission insist in its rule that RTOs play a significant role in setting any national reliability standards. Sithe suggests that RTOs should also have independent authority to modify existing rules, and/or to place new rules before the Commission for its review and approval in order to promote rules that intrude less into the markets and that promote efficiency goals, as well as system reliability.

Illinois Commission argues that the proposal is not adequate and that the Commission must more directly address the concern over lack of independence between reliability standards development, enforcement organizations and commercial market interests. Illinois Commission suggests some possibilities: (1) require NERC/regional reliability council reform so that the process of establishing and enforcing reliability guidelines, standards, and policies is independent of discriminatory generation/transmission owner influence; (2) require that all NERC/regional reliability council guidelines, standards, and policies be approved by FERC prior to their adoption; or (3) reform NERC so that it is independent of generation/transmission owners, then eliminate MAIN and ECAR and require the Midwest ISO to act as the regional standards setting entity and as the

[431] *See, e.g.,* NY ISO, Cal ISO, Nevada Commission, New York Commission.

[432] *See, e.g.,* Avista, Minnesota Power, SPRA, MidAmerican, Florida Power Corp.

[433] FERC Stats. and Regs. ¶ 32,541 at 33,738–39.

[434] *See, e.g.,* Entergy, NECPUC, NASUCA.

[435] *See, e.g.,* Cal ISO, Duquesne, Nevada Commission, Statoil.

reliability enforcement entity for the Midwest Region.

A few commenters seek clarification.[436] British Columbia Ministry requests that the Commission clarify how the RTO roles and responsibilities overlap with duties outlined for the Self Regulating Reliability Organization in the North American Electric Reliability Council's draft legislation. New York Commission and Iowa Board request that the Commission recognize the authority of the states to require the maintenance of electric system reliability.

NERC and several other commenters generally oppose the proposal. NERC urges the Commission to include an obligation that the RTO adhere to the reliability rules adopted by NERC and the relevant regional reliability council as a condition of becoming an RTO. NERC states that RTOs must be designed, implemented and operated consistent with NERC operating and planning policies. NERC notes it will revise its operating and planning policies to recognize and accommodate these emerging institutions, as necessary.

Several commenters such as Duke and SERC supports the work of NERC to establish consistently applied reliability standards and supports NERC's authority to enforce these standards. Duke also supports NERC and the regional reliability councils continuing to play a vital role in setting reliability standards. NERC oversight of reliability should prevent different RTOs from applying different standards and will ensure that inter-RTO reliability matters will be dealt with effectively. CEA suggests that the reliability responsibilities authorized for RTO's be respectful of the carefully balanced design of the evolving NERC/NAERO.

SRP requests that each RTO be required to join NERC, or NAERO when formed. In addition, other commenters such as SRP and Los Angeles propose that RTOs be required to use planning and design criteria that comply with the criteria established by the appropriate NERC (or NAERO when established) regional reliability council.

NYPP believes that properly constituted local and regional reliability councils authorized by FERC should have the authority to establish criteria necessary to maintain the reliability of the transmission system including the reliability of discrete locations (*e.g.,* the supply of reactive power to support voltage in load pockets).[437]

FirstEnergy requests that the role of the regional reliability councils be clarified with respect to regional RTOs. Also it would have us identify the need boundaries so that each RTO reports only to one regional reliability council. In addition, the regional reliability councils may need to undergo a transformation similar to NERC/NAERO to expand the role of the various industry segments.

Commission Conclusion. The Commission adopts the proposal in the NOPR that the RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. Although many commenters support this requirement, some pose additional questions regarding how this function will be performed by the RTO. Some commenters request that the Commission define better the time period associated with ''short-term'' reliability. We clarify that the term ''short-term'' is intended to cover transmission reliability responsibilities short of grid capacity enhancement. It includes all time periods, including but not limited to ''real-time,'' necessary for the RTO to satisfy its reliability responsibilities, up to the planning horizon. There is no time gap between what is included within short-term reliability and the RTO's planning responsibilities.

Commenters also request more specificity in describing the RTO's functions. The facilities that will be under RTO control, the specific functions that the RTO must perform, and how the RTO will execute its responsibilities and direct operations, are all defined above in the section on operational authority. PJM's additional request that the RTO have authority to collect information is discussed in both the operational authority and the market monitoring sections.

PG&E requests that the RTO rely on market mechanisms to maintain short-term reliability. PJM/NEPOOL Customers requests that reliability and commercial activities be kept separate. We will not require the RTO to rely on market mechanisms in every instance to maintain short-term reliability. The Commission believes that some reliability functions may not be conducive to supply through competitive market mechanisms since a reliable power system provided to one customer cannot be withheld from other customers, *viz.,* many reliability functions are, in economic terms, ''public goods.'' In Order No. 888, we identified some functions necessary to maintain grid reliability as ancillary services and required them to be provided as separate products. These services and their potential inclusion in emerging markets is discussed in the section on ancillary services below. We cannot conclude at this time that it is appropriate to rely solely on market mechanisms to supply the reliability functions that the transmission system operator must perform, but we expect that over time most of the generation services that perform these functions will be competitively procured.

Interchange Scheduling. We conclude that the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules, which are often coincident with schedules for unbundled transmission service. This function will automatically be assumed by RTOs that operate a single control area. If the RTO structure includes control area operators who are market participants or affiliated with market participants, the RTO will have the authority to direct the implementation of all interchange schedules. As stated in the NOPR, a remaining concern is that non-RTO control area operators, who are also competitors in energy markets, have unequal access to commercially sensitive information and could use this knowledge of their competitors' schedules and transactions to gain an unfair competitive advantage in the energy markets. In the event that the RTO filing includes a structure in which non-RTO control area operators receive sensitive information, we will require the RTO to monitor for any unfair competitive advantage, and report to the Commission immediately if problems are detected. In addition, to address concerns about protecting commercially sensitive information, we will require the RTO or any entities who operate control areas within the RTO's region that require access to commercially sensitive information to sign agreements that separate reliability personnel and the relevant information they receive from their wholesale merchant personnel.

Redispatch Authority. We conclude that the RTO must have the right to order the redispatch of any generator connected to the transmission facilities it operates, if necessary for the reliable operation of the transmission system.[438]

[436] *See, e.g.,* Canada DNR, Manitoba Board, Cal DWR, Entergy, Minnesota Commission, PSE&G.

[437] The Commission has authorized the establishment of the New York State Reliability Council and has accepted the relationship between it and the NY ISO.

[438] Redispatch for congestion management is addressed under different rules, as discussed in the section on congestion management.

We also require each RTO to develop procedures for generators to offer their services and to compensate generators that are redispatched for reliability. In order to maintain the reliability of the transmission system, the entity that controls transmission must also have some control over some generation. In general, we believe this control should be through a market where the generators offer their services and the RTO chooses the least cost options. This authority does not extend to initial unit commitment and dispatch decisions for generators. However, for reliability purposes, the RTO should have full authority to order the redispatch of any generator, subject to existing environmental and operating restrictions that may limit a generator's ability to change its dispatch.

Some commenters request that we define what is meant by redispatch for reliability. We clarify that we intend the authority for generator redispatch to be used by the RTO to prevent or manage emergency situations, such as abnormal system conditions that require automatic or immediate manual action to prevent or limit equipment damage or the loss of facilities or supply that could adversely affect the reliability of the electric system, or to restore the system to a normal operating state.[439]

Transmission Maintenance Approval. We conclude that, when the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards. Control over transmission maintenance is a necessary RTO function because outages of transmission facilities affect the overall transfer capability of the grid. If a facility is removed from service for any reason, the power flows on all regional facilities are affected. These shifting power flows may cause other facilities to become overloaded and, consequently, adversely affect system reliability.

The RTO is expected to base its approval on a determination of whether the proposed maintenance of transmission facilities can be accommodated within established state, regional and national reliability standards. The RTO's regional perspective will allow it to coordinate individual maintenance schedules with other RTOs as well as with expected seasonal system demand variations. Since the RTO will have access to extensive information, it will be able to make more accurate assessments of the reliability effect of proposed maintenance schedules than individual, sub-regional transmission owners.

If the RTO is a transmission company that owns and operates transmission facilities, these assessments will be an internal company matter. However, if there are several transmission owners in the RTO region, the RTO will need to review transmission requests made by the various transmission owners.[440] In this latter case, we expect the RTO to: receive requests for authorization of preferred maintenance outage schedules; review and test these schedules against reliability criteria; approve specific requests for scheduled outages; require changes to maintenance schedules when they fail to meet reliability standards; and update and publish maintenance schedules as needed.

We conclude that, if the RTO requires a transmission owner to reschedule planned maintenance, the transmission owners should be compensated for any costs created by the required rescheduling only if the previously scheduled outage had already been approved by the RTO.

We encourage the RTO to establish performance standards for transmission facilities under its direct or contractual control. Such standards could take the form of targets for planned and unplanned outages. The rationale for this requirement is that two transmission owners should not receive equal compensation if one owner operates a reliable transmission facility while the other operates an unreliable facility. For RTOs that are transcos, we will require that such quality standards be made explicit in any rate proposal.

Generation Maintenance Approval. We conclude that the RTO is not required to have authority over proposed generation maintenance schedules. However, we acknowledge that there are reliability advantages to the RTO having this authority, and we would accept RTO proposals where the participants choose to grant the RTO such authority. In our order approving the Midwest ISO, we observed that "the dividing line between transmission control and generation control is not always clear because both sets of functions are ultimately required for reliable operation of the overall system." [441] Because of this close connection between generation and maintenance of system reliability, it is essential for generator owners and operators to provide the RTO with advance knowledge of planned generation outage schedules so that the RTO can incorporate this information into its reliability studies and operations plan. However, although a generator may be required to submit its maintenance schedule to an RTO, the RTO should be prohibited from sharing that information with any other market participants, or affiliates of market participants.

Facility Ratings. After consideration of the comments, we conclude that it is inappropriate here to require RTOs to establish transmission facility ratings. We encourage, however, such ratings to be determined, to the extent practical, by mutual consent of the transmission owner and the RTO, taking into account local codes, age and past usage of the facilities.

The Commission acknowledges the concern that changes in existing equipment ratings may lead to problems of equipment safety and possible damage. We further recognize that the RTO may initially need to rely upon existing values for equipment ratings and operating ranges so as not to disrupt reliable system operation. However, as an RTO gains experience operating or directing the operation of the transmission facilities in its region, we expect this responsibility to migrate to the RTO, as facility ratings have at least an indirect effect on the ability of the RTO to perform other RTO minimum functions (*e.g.,* planning and expansion, ATC and TTC). If there is a dispute over equipment ratings, the parties should pursue resolution through an ADR process approved by the Commission.

Liability. After consideration, we will determine the extent of RTO liability relating to its reliability activities on a case-by-case basis.

Reliability Standards. We conclude that the RTO must perform its functions consistent with established NERC (or its successor) reliability standards, and notify the Commission immediately if implementation of these or any other externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service.

[439] In general, a power system can be in one of three states: normal, emergency and restorative. When all constraints and loads are satisfied, the system is in its normal state; when one or more physical limits are violated, the system is in an emergency state; and when part of the system is operating in a normal state yet one or more of the loads is not met (partial or total blackout), the system is in a restorative state.

[440] Since some of these transmission owners may also own generation, they may have an incentive to schedule transmission maintenance at times that would increase the prices received from their power sales. A transmission company, not affiliated with any generators, would not have these same incentives.

[44] Midwest ISO, 84 FERC at 62,180.

E. Minimum Functions of an RTO

In the NOPR, we proposed seven minimum functions that an RTO must perform. In general, we proposed that an RTO must:

(1) administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;

(2) create market mechanisms to manage transmission congestion;

(3) develop and implement procedures to address parallel path flow issues;

(4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;

(5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;

(6) monitor markets to identify design flaws and market power; and

(7) plan and coordinate necessary transmission additions and upgrades.

We basically affirm these seven functions with the clarifications and revisions as noted below. In addition, we have added interregional coordination as an eighth minimum function, as discussed below.

1. Tariff Administration and Design (Function 1) Sole Administrator of Tariff

In order to ensure non-discriminatory service within the region, the NOPR proposed that the RTO be the sole administrator of its own transmission tariff.[442] The RTO would thus be the sole authority making decisions on the provision of transmission service including decisions relating to new interconnections. The NOPR requested comments on several aspects of this standard, including how the authority over interconnections would work for ISOs that do not own transmission and would not be performing the construction. The NOPR also sought comment on whether authority over interconnection should apply to all new interconnections, including those for reliability and connections to other regions.

Comments. The vast majority of commenters addressing these issues agree with the proposal that the RTO be the sole administrator of its own tariff.[443] Commenters noted many of the benefits of an RTO being the sole tariff administrator: it will eliminate confusion; reduce transactions costs; assure that access decisions are independent;[444] reduce reliability concerns;[445] and ensure consistent ratemaking across the RTO.[446] Some commenters suggest that their respective organizations already meet this requirement, including ISO–NE and NY ISO, which ask whether sharing authority with transmission owners for non-discriminatory access meets the standard.

But some of the commenters that support the proposal had specific concerns and suggestions: the Commission should adopt specific pricing regulations and expressly permit expedited declaratory orders on pricing;[447] the Commission should take a more active approach in developing innovative rates;[448] there may be a problem for an RTO located in both the United States and Canada if there is disagreement over the tariff by the respective authorities;[449] and quicker decisions are likely if a stakeholder board is not involved.[450]

A number of commenters also supported the proposal with respect to the RTO's authority over interconnections.[451] Some of these commenters expressed concerns and recommendations about the Commission's proposal, *e.g.,* transmission owners should be a part of the decision process;[452] transcos will be better able to integrate interconnection decisions into a unified strategy covering investment, operations, maintenance and facility design;[453] RTOs should not have the authority to deny a generator that is not optimally located on the grid;[454] interconnection policy should rely more heavily on market mechanisms;[455] the transmission owner should develop the actual interconnection agreement to insure adequate protections for its equipment;[456] national fees and technical standards should be established for interconnections;[457] authority over interconnections should involve coordinated planning and construction, not ''autonomous, unilateral authority'';[458] RTOs need to develop procedures and guidelines so that there are no adverse impacts of interconnection on existing facilities;[459] RTOs should have authority to assess the impact of a new interconnection on regional facilities but should only have authority over interconnections involving RTO facilities, not all regional facilities;[460] and an RTO must be required to show harm to deny an interconnection request.[461]

A few commenters opposed the Commission's proposal or suggested making significant modifications. With respect to tariff administration, Seattle opposes the Commission giving RTOs with small control areas blanket authority to approve new interconnections and also argues that the RTO should not be given authority over the interconnection of customer based backup and load shaving generators, QFs, or subtransmission and radial transmission facilities (used to reinforce municipal grids). TXU Electric argues that the Commission should be more flexible and allow RTOs to choose whether to administer the tariff of other entities. TXU Electric notes that in ERCOT, each owner has its own tariff with its own revenue requirement but with uniform terms and conditions of access and that this approach can protect the owner better than an RTO tariff. Florida Commission recommends that the question of tariff administration be determined on a regional basis with endorsement by state regulators.

With respect to RTO authority over interconnections, Mass Companies argues that the RTO should not have the authority over interconnections because such authority is unlawful, impairs reliability, and because the transmission owner is in a better position to perform this function. SRP suggests that an RTO's exclusive right to administer its own tariff and the right to control interconnections may establish a property right that would jeopardize a public power's tax free status by being declared a private business use. This would be a potential problem if the RTO were not a governmental entity or a 501(c)(3) non-profit organization. To prevent this, SRP says that the RTO would have to be structured carefully with these concerns in mind. DOE indicates that the authority over interconnection is a concern for PMAs

[442] FERC Stats. and Regs. ¶ 32,541 at 33,739–740. The authority to file changes in the RTO tariff is discussed above under the Independence Characteristic.

[443] *See, e.g.,* Allegheny, APX, SMUD, NASUCA, NY ISO, East Kentucky, Utilicorp, JEA, LG&E, Enron/APX/Coral Power, EPSA, South Carolina Authority, First Energy, Cal DWR, California Board, PacifiCorp and NSP.

[444] PJM.

[445] PJM/NEPOOL Customers.

[446] UAMPS.

[447] Entergy.

[448] Illinois Commission.

[449] Canada DNR.

[450] New Smyrna Beach.

[451] *See, e.g.,* Entergy, PJM, South Carolina Authority, Southern Company, Tri-State, Desert STAR, East Texas Cooperatives, Enron/APX/Coral Power, Sithe and PG&E.

[452] Cal ISO.

[453] Duke.

[454] Minnesota Power.

[455] PG&E.

[456] Southern Company.

[457] Distributed Power and EAL.

[458] SPRA.

[459] TANC.

[460] Metropolitan.

[461] Williams.

because of the NEPA requirements which must be accommodated. Industrial Consumers would amend the proposed Regulatory Text on tariff administration to add ''throughout the interconnection within which the Regional Transmission Organization resides'' to the requirement to promote efficient use and expansion. Industrial Consumers also propose that the Regulatory Text on interconnection be amended to add the responsibility to coordinate transmission needs across the interconnection. Finally, Industrial Consumers would amend the provision that RTOs review and approve requests for new interconnections to add ''by new loads that take service at transmission voltages and by any new generation resource regardless of the nominal voltage at the generator's point of interconnection. Any proposal to increase the nameplate-rated capacity at an existing generating site shall be treated as a new request for interconnection'' to clarify that the RTO is to authorize such interconnections and minimize entry barriers to new sources of generation.

Commission Conclusion. We note the strong support for this standard in the comments and we adopt the NOPR's requirement that the RTO be the sole provider of transmission service and sole administrator of its own open access tariff. Included in this is the requirement that the RTO have the sole authority for the evaluation and approval of all requests for transmission service including requests for new interconnections.[462]

With the RTO the sole provider of transmission service, transmission customers have a nondiscriminatory and uniform access to regional transmission facilities. This type of access cannot be assured if customers are required to deal with several transmission owners with differing tariff terms and conditions. As noted in the NOPR, the RTO must be the provider of transmission service in the strong sense of the term. Mere monitoring and dispute resolution are insufficient to meet the requirements of this standard.

The requirement that the RTO administer its own tariff and not the tariff or tariffs of other entities received little objection in the comments, even from ISOs where this requirement is not currently being met.[463] One commenter, SCE&G proposes that the RTO's tariff only cover its own costs and wheeling. The transmission owners would maintain standard open access tariffs which would be administered by the RTO. We reject this proposal. To provide truly independent and nondiscriminatory transmission service, the RTO must administer its own tariff and have the independent authority to file tariff changes.

Mass Companies argues that the RTO is not in as good a position as transmission owners to judge requests for new interconnections. SPRA and Metropolitan suggest that an RTO's authority over new interconnections should be limited. Because the ability for customers to obtain nondiscriminatory access to the regional transmission system, whether over existing facilities or over new facilities, is integral to a competitive market for generation, we reject these proposals to modify our original position on new interconnections.

Other commenters, as noted above, support this standard but have specific concerns they would like to see the Commission address. The concerns listed do not cause us to change our original proposal. These concerns, to the extent they apply, should be voiced at the time RTO proposals are filed and they will be considered on a case-by-case basis.

Multiple Access Charges. The NOPR proposed that the RTO's tariff must not result in transmission customers paying multiple access charges. We affirm that proposal in this Final Rule. Because the issue of multiple access charges is a rate issue, we discuss in detail the comments we received on this issue, the reasons for our conclusion, and the concepts of pancaked rates, license plate rates, and uniform access charges in Section III.G of this Final Rule addressing transmission ratemaking policy for RTOs.

2. Congestion Management (Function 2)

In the NOPR, we proposed to include congestion management as a minimum function that an RTO must perform.[464] Specifically, we proposed to require the RTO to ensure the development and operation of market mechanisms to manage transmission congestion. We proposed that the RTO must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant. In carrying out this function, we stated that the RTO must satisfy certain standards or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard. We further proposed that the market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions. We proposed to allow RTOs considerable flexibility in experimenting with different market approaches to managing congestion through pricing. However, we stated that proposals should ensure that (1) the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and (2) limited transmission capacity is used by market participants that value that use most highly. We asked for comments as to what specific requirements, if any, may best suit these goals.[465]

We stated in the NOPR that traditional approaches to congestion management such as those that rely exclusively on the use of administrative curtailment procedures may no longer be acceptable in a competitive, vertically de-integrated industry. We thus concluded that efficient congestion management requires a greater reliance on market mechanisms, and stated our belief that a large regional organization like an RTO will be able to create a workable and effective congestion management market. We stated that while it is our intent to give RTOs considerable flexibility in experimenting with different market approaches to managing congestion, we believe that a workable market approach should establish clear and tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices.

The Commission invited comments on the requirement that RTOs must be responsible for managing congestion with a market mechanism, and posed the following questions. Can decentralized markets for congestion management be made to work effectively and quickly? Can the RTO's role be limited to that of a facilitator that simply brings together market participants for the purpose of engaging in bilateral transactions to relieve congestion? If not, will these markets require centralized operation by the RTO or some other independent entity? How can an RTO ensure that enough generators will participate in the congestion management market to make possible a least-cost dispatch? Are there any special considerations in evaluating

[462] Of course, eligible applicants always have the right to seek interconnections from the Commission pursuant to sections 202(b) and 210 of the FPA.

[463] *See, e.g.,* ISO–NE at 9.

[464] FERC Stats. & Regs. ¶ 32,541 at 33,741–43.

[465] *Id.* at 33,754–55.

market power in a congestion market operated or facilitated by an RTO? In addition, we proposed to allow up to one year after start-up for this function to be implemented. We noted that market approaches to congestion management may take additional time to work out, and asked for comments on whether this additional implementation time period is warranted, and whether one year is an appropriate additional time period.

Comments. Using Market Mechanisms to Manage Congestion. Although opinions vary as to the proper role of the RTO in managing congestion, many commenters believe that efficient congestion management requires greater reliance on market mechanisms.[466] CSU believes that congestion management is uniquely amenable to a market solution. CSU states that there will be a continuing need for some type of market mechanism to address constraints and this mechanism is best established at the regional level and best placed with an entity independent of wholesale power market participants.

Some commenters emphasize that it is better to use market mechanisms to manage congestion than to rely on the physical interruption of power flows.[467] NERC contends that if the industry had in place more market-oriented mechanisms that dealt effectively with constraints, then the frequency of transmission loading relief (TLR) procedures would decrease. Professor Hogan claims that with efficient pricing, users have the incentive to respond to the requirements of reliable operation. He asserts that, absent such price incentives, market choices would need to be curtailed in order to give the system operator enough control to counteract the perverse incentives that would be created by prices that did not reflect the marginal costs of dispatch. PJM/NEPOOL Customers argues that, when faced with a transmission congestion circumstance, the RTO should redispatch generators to the extent possible.

Also, Statoil claims that the use of TLR procedures is inherently discriminatory. Statoil claims that most transmission owners serving retail load do not engage in interchange transactions or use the pro forma tariff at the same level as new competitive market entrants attempting to enter historically captive markets. Statoil thus argues that, even if TLR is applied in a comparable manner, it will still disproportionately and adversely affect new competitive market entrants.

Role of the RTO in Congestion Management. Commenters offer a variety of views concerning the proper role of the RTO in congestion management. Some advocate an active role for the RTO in operating an energy market that is highly centralized.[468] Others envision the RTO's role as being much smaller, perhaps limited to that of a facilitator that brings together market participants for the purpose of engaging in voluntary transactions to relieve congestion.[469] Still others, such as Southern Company and EEI, believe that RTOs are not necessary to make congestion management work. EEI argues that while congestion management does require a coordinated regional or interconnection-wide solution, it does not require the extensive infrastructure and responsibilities associated with what the Commission has proposed to define as RTOs. EEI notes that NERC's Congestion Management Working Group is exploring available options for congestion management, independently of whether RTOs exist.

PJM/NEPOOL Customers believes that an independent entity must operate any congestion management market. It believes also that that entity must have sufficient power and centralization to address congestion problems effectively and quickly. Consequently, it urges the Commission not to consider proposals that include a decentralized market for congestion management or that limit the RTO role to that of a facilitator of bilateral transactions to relieve congestion. In addition, it contends that the RTO must retain sufficient authority over generators that choose to make themselves available to ensure that those generators will participate in the congestion management market. Duke states that, eventually, decentralized markets may organize in a manner to accomplish effective congestion management, but at this time, the congestion management function should be centrally managed.

PJM claims that RTOs can facilitate efficient, broad-scale congestion management. PJM states that by combining multiple transmission systems over a large geographic region, an RTO can have an effective pricing system to price efficiently actual transmission flows in a region. PJM argues that not only should the Commission require that RTOs be responsible for managing congestion with market mechanisms, the Commission also should prohibit any other entity from acting in a manner that detracts from the RTO's ability to employ its market mechanisms.

Cleveland believes that an effective way to manage congestion may be to combine a market-based mechanism with a power exchange. It states that the RTO's redispatch function and the bidding process available through a power exchange should jointly operate to minimize the congestion.

H.Q. Energy Services contends that control over the management of congestion goes hand-in-hand with control over reliability. It believes that, ideally, an RTO should establish a congestion pricing system that manages congestion with minimal operator intervention. However, H.Q. Energy Services argues that, without control over reliability, an RTO will not be in the position to accurately and fairly allocate available transmission capacity because it cannot send the correct congestion pricing signals.

Sithe contends that the Commission should not allow overly decentralized systems whereby individual utilities in a region continue to manage congestion relief, especially if those utilities continue to own generation. Arkansas Consumers believe that the RTO's congestion management function helps provide a remedy for any anti-competitive activity on the part of generators or transmission owners. First Rochdale contends that only fully independent operation of an RTO is likely to lead to open markets in which all entities can compete freely. Duke asserts that there are no special considerations in evaluating market power in a congestion market operated or facilitated by an RTO.

Other commenters stress that the RTO's role in managing congestion using market mechanisms should be strictly limited. Indeed, the South Carolina Authority opposes a centralized arrangement for managing congestion as being unduly restrictive and perhaps anti-competitive. WPSC argues that the role of the RTO should be limited to acting as a clearinghouse so that market participants are aware of the range of alternatives available for dealing with congestion. WPSC contends that the market will then dictate which mechanisms are used in any particular instance. SPP suggests that the RTO can be a facilitator of congestion relief and that there is no need for the Commission to require that the RTO adopt a centralized approach,

[466] *See, e.g.,* United Illuminating, CSU, Duke, NASUCA, Los Angeles, NYPP, DOE, SMUD, Otter Tail, PG&E, FirstEnergy, Mass Companies, Enron/APX/Coral Power, Nevada Commission.

[467] *See, e.g.,* NERC, Sithe, NASUCA, Cinergy, Professor Hogan, PJM, Dr. Ilic.

[468] *See, e.g.,* PJM, Professor Hogan, CSU, Sithe, NERA, Duke, PJM/NEPOOL Customers, H.Q. Energy Services, Minnesota Power, FTC.

[469] *See, e.g.,* APX, SPP, South Carolina Authority, Alliant Energy, WPSC, NSP, TANC, Williams.

such as locational marginal pricing, for managing congestion. SPP states that it is a facilitator of congestion relief and intends to continue in that role under its new proposal. SPP states that it will identify which generators can relieve a constraint and the relative impact of redispatching those generators. It will then be the customer's responsibility to contract with the owner of these generators for redispatch services. SPP notes that this method relies on the market and bilateral contracts for the redispatch solutions. SPP claims that the market can also provide for price assurance and for long-term redispatch obligations. PG&E claims that with the proper information, bilateral market-based redispatch could be used within an hour of the occurrence of congestion on any part of the controlled system.

APX argues that the RTO should not conduct the trading process because it will impede the adaptation of trading to market conditions, which is essential for market development. APX claims that all competitive industries use decentralized trading through forward contracts, and no competitive industry uses a central bidding agent to create its market. Consequently, APX believes that the Commission should limit the RTO's role in congestion management to that of a provider of last resort. PG&E argues that although the RTO may administer certain market mechanisms such as congestion management, it is important that the RTO not view itself as responsible for energy pricing and other aspects of supply and demand interactions, all of which, PG&E contends, can be most effectively managed by the market unless material and lasting market flaws are present.

Similarly, Cinergy argues that the mechanism for price transparency in the commodity market should be developed and implemented by the market, not the RTO. Cinergy recognizes, however, that an economic congestion management system depends on a power market mechanism that provides price transparency for determining economic dispatch of generation. Consequently, Cinergy notes, RTOs will be confronted with issues of applying an economic dispatch valuation mechanism. Cinergy argues that such mechanism should evolve from the marketplace, not directly from the RTO. Cinergy proposes that the RTO would administer the congestion management system, but would not be involved in the commodity market infrastructure unless its involvement was mutually agreeable among all stakeholders.

Williams claims that decentralized markets for congestion management, operating under the auspices of RTOs, can work effectively and quickly in an environment in which market participants have the correct incentives. Williams states that depending upon the geographic size of RTOs and the extent of congestion within each, zones for congestion management may have to be developed. Williams provides a detailed description of how a zonal approach to congestion management can be implemented.

Both CP&L and Enron/APX/Coral Power believe that the role of the RTO in congestion management should depend on the time frame in which the decisions are being made. These commenters prescribe different roles for the RTO in each of three different time frames.

The Direct Dispatch Authority of the RTO. While supporting the use of pricing and other market mechanisms to manage congestion, a number of commenters state that an RTO must have authority to direct redispatch if necessary to ensure grid reliability.[470] For example, Otter Tail contends that the RTO should have direct authority to order redispatch of generation for purposes of relieving congestion and during system emergencies. Otter Tail states that this dispatch should be directed for the generating units that can most economically reduce the congestion. Otter Tail states that because there is a need for immediate, real-time response to system contingencies and to relieve transmission congestion, the RTO should have control of generating units. East Kentucky contends that to effectively manage congestion, the RTO must have absolute authority to order redispatch of all generators on the RTO transmission system. However, for this to work, East Kentucky states that the RTO will have to compensate the generator with firm transmission service for the additional out-of-pocket costs incurred due to the redispatch, plus an amount for lost margins on lost revenue. It suggests that generators with non-firm transmission service would have to redispatch as directed by the RTO but would have to bear their own costs.

NERC notes that market mechanisms may offer better ways of dealing with congestion management than does physical interruption of power flows, but asserts that it will always be necessary to have a non-market mechanism such as transmission loading relief in place to ensure that the stability of the grid is always maintained. However, EME believes that the extent of RTO control over dispatch of generation should be carefully circumscribed to ensure maximum development of competitive markets in wholesale power and ancillary services. Seattle contends that where transparent power supply markets exist, price differences are widely known to the market and congestion can be resolved bilaterally with no intervention by an RTO. PJM notes that since implementing LMP, it rarely has needed to take emergency actions to alleviate transmission congestion.

Minnesota Power believes that RTOs must have the authority to require that all generators, existing and new, agree to redispatch as a condition of grid connection. Minnesota Power also believes that the RTO must have the authority to penalize generators who subsequently refuse a redispatch order, or claim a false unplanned outage. CSU asserts that generation redispatch is essential in Front Range Colorado, which can be expected to have an increasing population of gas-fired generation within the boundaries of the constraints. It contends that the inability to redispatch these units for any reason other than reliability would severely hinder the ability of an RTO to address capacity constraints.

MidAmerican states that, although congestion must be managed using pricing signals from the market, circumstances may occur where immediate actions are required and time does not permit normal bidding to allow the marketplace to respond. It contends that during such events, the RTO must be required to follow previously established procedures.

However, Seattle argues that the RTO should not have authority to redispatch generation to accomplish congestion management without unanimous consent of the stakeholders. Seattle notes that many Northwest generating plant operators are subject to fishery-related hydroelectric dispatch constraints. Seattle states that because these constraints are particular to the owners of the generating facilities, these resources are not well suited to third party dispatch.

Managing Congestion by Eliminating It. Some commenters contend that the ultimate goal of RTOs should be the elimination of congestion within their respective areas of control.[471] Powerex believes that it is better to eliminate congestion at its source through facilities upgrades, if economically and environmentally feasible, rather than

[470] *See, e.g.,* Otter Tail, NERC, Allegheny, EME, NASUCA, East Kentucky, Williams, Minnesota Power, CSU. *See also supra* section III.D.3, which addresses the appropriate scope of the RTO's operational authority.

[471] *See, e.g.,* Williams, Powerex, Manitoba Board, Salomon Smith Barney.

attempting to manage congestion on a long-term basis through congestion pricing schemes. Salomon Smith Barney believes that the Commission has overemphasized congestion pricing as a vehicle to price the existing network rather than as a vehicle to induce investment when such investment is an economical alternative.

TDU Systems state that they do not want management of significant transmission congestion to become a long-term function of RTOs. They claim that minor congestion (*i.e.,* congestion that is economically dealt with through redispatch of generators) will always be a feature of wholesale transmission markets, and an RTO should properly manage it. However, they argue that an RTO should deal with significant persistent transmission congestion by constructing (or having constructed) the appropriate transmission or generation facilities.

Desirable Attributes of Market Mechanisms. Many commenters offer their views on the desirable attributes of any market mechanisms that are used to manage congestion.[472] For example, PJM/NEPOOL Customers urges the Commission to employ three general criteria to evaluate any proposal: simplicity, visibility and predictability. They state that the proposed approach to relieve the congestion should be simple to administer, both for customers and for the RTO. They believe that market participants should be able to examine the operation of the congestion management mechanism on a real-time basis and verify that transmission access is being appropriately accorded to entities that most desire transmission service. They state that such visibility will engender confidence by market participants in the congestion management mechanism. In addition, they believe that the congestion management mechanism must be predictable to all transmission users to determine the anticipated price that will be necessary to ensure the continuation of transmission service if congestion occurs.

Cinergy states that an economically efficient congestion management system must begin with properly defining information posting requirements. Accordingly, Cinergy argues that the Final Rule should ensure that requisite information on congestion is posted on the OASIS. Similarly, Williams and Industrial Consumers believe that RTO access to region-wide information on network conditions and power transactions, coupled with efficient congestion management and well specified transmission rights, could help RTOs in taking preemptive actions against potential curtailment incidents. Statoil and EPSA believe that, ideally, economic rationing schemes should be uniform across RTOs and should be implemented as an ancillary service under a regional transmission tariff. Montana Commission asserts that congestion management must be efficient. CMUA believes that congestion management mechanisms must do their job, but not unreasonably interfere with choices by market participants.

Some commenters believe that efficient congestion management requires a transparent commodity market. Cinergy states that market mechanisms that include locational pricing and financial rights for firm transmission have been successfully implemented where they are supported by a power exchange or pool pricing mechanism that provides market-clearing prices and price transparency. CalPX emphasizes the value of a separate power exchange and argues that the bifurcation of the exchange and transmission operator functions does not add to the market cost of congestion management, as some have suggested. Also, Otter Tail believes that the development of an hour-ahead power exchange within the RTO would improve grid reliability.

Many commenters support the NOPR's requirement that market mechanisms be used to manage congestion and note the particular value of using price as a tool to manage congestion.[473] Some commenters specifically endorsed the proposed requirement that congestion pricing proposals must meet the two efficiency objectives set forth in the NOPR.[474] PJM/NEPOOL Customers state that these two objectives are fundamental to the operation of a market and to the ultimate goals of electricity supply competition.[475] SMUD believes that a well-designed congestion management policy, that provides proper locational price signals without creating opportunities for gaming or cost shifting, will attract market participation. SMUD agrees that market participants must be given efficient price signals concerning their use of the transmission system, but claims that this is difficult because the existing transmission grid was not designed with the capability to operate as a common carrier or to serve customers in an open access manner. Also, a few commenters expressed doubts about the overall value of using pricing mechanisms to manage congestion,[476] and others cited reasons to move cautiously.[477] Tri-State is skeptical that market mechanisms for managing congestion will lead to a least-cost dispatch. Tri-State states that entities with firm transmission rights on the congested path may be reluctant to participate voluntarily in generation redispatch that will jeopardize the economics of long-term power supply contracts or firm resources, even if the result would lower costs.

Several commenters suggest principles to guide the design of congestion pricing mechanisms.[478] NASUCA states that any mechanism for using congestion prices for managing transmission system flows should be easy to implement; designed to minimize cost shifts; designed to support an economically efficient dispatch; and coordinated with the underlying transmission rate design. PacifiCorp states that key components of a good market-based congestion clearing methodology are: (1) Tradable transmission capacity reservations; (2) a system in which all parties who can clear congestion can bid to do so; (3) the establishment of congestion costs far enough in advance to facilitate reasoned decision-making; and (4) the avoidance of any RTO rules that substantially reduce liquidity in power markets. UtiliCorp believes that a congestion management system should establish tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary market for transmission rights, and give market participants the opportunity to hedge locational differences in energy prices. However, Enron/APX/Coral Power disagrees on the latter feature. It contends that the monopoly wires business should not be allowed to encroach on what they see as the highly competitive and innovative business of providing hedges against locational price differences of energy or capacity or against price volatility of these or any other competitive products.

Cal DWR and Metropolitan urge the Commission to adopt RTO ratemaking principles that include off-peak rates.

[472] *See, e.g.,* NASUCA, CMUA, NSP, PG&E, Statoil, SMUD, UtiliCorp, PacifiCorp, PJM/NEPOOL Customers, Metropolitan, Cal DWR.

[473] *See, e.g.,* PJM/NEPOOL Customers, United Illuminating, Allegheny, EPSA, SMUD, Los Angeles, NASUCA, Duke, NERC, Professor Hogan, EME, PJM, DOE, CSU.

[474] *See, e.g.,* PJM/NEPOOL Customers.

[475] However, Montana Commission asks the Commission to specify more precisely the nature of the pricing and congestion management methods that will satisfy the NOPR's efficiency objectives.

[476] *See, e.g.,* LIPA, Transmission ISO Participants.

[477] *See, e.g.,* EPSA, Tri-State.

[478] *See, e.g.,* NASUCA, NJBUS, PJM/NEPOOL Customers, EPSA, Enron/APX/Coral Power.

Cal DWR believes that customers should face accurate transmission price signals and, therefore, transmission prices should be lower in periods of off-peak demand for transmission. Cal DWR believes that off-peak pricing provides an accurate price signal over the longer term, promoting investment necessary to shift transmission usage to off-peak periods. In addition, Metropolitan believes that off-peak pricing can help to resolve problems of cost-shifting.

A number of commenters emphasize certain benefits of a well designed congestion pricing policy, claiming that price signals can assist RTOs and market participants in determining the efficient size and location of both new generation and new grid expansions.[479] Los Angeles argues that ensuring accurate market signals through the creation of a congestion pricing mechanism will be the keystone to future system planning. Los Angeles states that these signals should alert generators to the advantages of siting in congested areas, motivate marketers and distribution companies to develop demand-side management options, and generally foster marketplace innovation. Los Angeles also believes that congestion price signals should help in determining the proper size of transmission upgrades that the RTO might build to relieve congestion. Otter Tail believes there exists a great need for new transmission capacity and, indeed, argues that the overall focus of the NOPR and FERC transmission policy should be on providing the appropriate financial incentives to assure investment in and expansion of the system.[480] To ensure that price signals translate into appropriate expansion of the grid, SMUD believes that the RTO must be sufficiently independent and strong to require the expansion of the grid. NASUCA notes that, while congestion cost pricing may help to signal where new generation and transmission lines are needed, it may not be necessary for the efficient daily operation of the transmission grid.

Other commenters believe that it may be difficult to design market mechanisms to provide incentives for the efficient expansion of the grid.[481] H.Q. Energy Services states that currently, the rules for congestion management do not act as a sufficient incentive to transmission owners to upgrade facilities. NWCC states that it is unclear whether congestion charges can act as a means of driving transmission expansion, since adding transmission is, by nature, capacity-based. NWCC also states that it is unclear whether congestion costs will be an adequate incentive for market participants to finance transmission expansion on their own, given the extensive permitting and regulatory requirements that are involved. LIPA states that, while new location-based pricing mechanisms have not been in place long enough to determine if they will provide empirical evidence that is helpful in identifying efficient transmission expansions, it believes that the mechanisms do not provide sufficient incentives for development of transmission. Also, LIPA claims that they do not provide a useful signal when reliability, as opposed to economic efficiency, drives the need for transmission enhancements.

SoCal Edison criticizes the congestion management policies implemented by the Cal ISO, stating that procedures intended to encourage the voluntary mitigation of congestion through investment in new transmission may not provide a sufficient incentive. SoCal Edison contends that, while correct congestion price signals will assist in the identification of transmission investment needs, they will not eliminate fundamental disputes among affected market participants over the responsibility for the costs of new transmission or eliminate the risks associated with attempting to construct new transmission projects. It asserts that the Commission cannot simply assume that the market will respond to congestion signals if, at the same time, it is creating a regulatory climate that discourages investment in new transmission. SoCal Edison believes that impediments to grid expansion can be overcome only if the Commission adopts transmission pricing policies that more accurately reflect the value that new transmission investments bring to electric consumers. Similarly, FirstEnergy argues that if the Commission desires an efficient generation market that optimizes the public good, then a mechanism that allows transmission owners to capitalize on increases in the transmission capacity at fair market value must be found. FirstEnergy contends that the interaction of these free market forces will drive the proper allocation of resources between transmission and generation over the long term.

Locational Marginal Pricing. A number of commenters advocate the use of locational marginal pricing (LMP) for congestion management.[482] Professor Hogan states that, with LMP, the security-constrained economic dispatch process would produce prices for energy at each location, incorporating the combined effect of generation, losses and congestion. He states that the corresponding transmission price between the location where power is supplied and where it is used would be determined as the difference between the energy prices at the two locations. Professor Hogan therefore contends that this same framework is easily extended to include bilateral transactions. Professor Hogan states that, with LMP, the system operator coordinates the dispatch and provides the information for settlement payments, with regulatory oversight to guarantee comparable service through open access to the pool run by the system operator through a bid-based economic dispatch. He claims that PJM implemented LMP after experimenting with an alternative market model and pricing approach that proved to be fundamentally inconsistent with a competitive market and user flexibility. He states that the earlier pricing system allowed market participants the flexibility to choose between bilateral transactions and spot purchases, but did not simultaneously present market participants with the costs of their choices. He states that this created perverse incentives. Professor Hogan argues that LMP is the only workable system that can support a non-discriminatory competitive market that allows for participant choice and flexibility.

PJM states that the Commission correctly concludes that LMP will ''encourage efficient use of the transmission system, and facilitate the development of competitive electricity markets.'' PJM notes that, under LMP, transmission customers are assessed congestion charges consistent with their actual use of the system and the actual redispatch that their transactions cause. It claims that this provides an economic choice to non-firm transmission customers to self-curtail their use of the transmission system or pay congestion charges determined by the market. PJM believes that by basing congestion charges on the true redispatch cost, parties behave in a rational and efficient manner. It states that the market determines the clearing price for transmission congestion and which customers ultimately utilize the transmission system. PJM states that the use of fixed transmission rights (FTRs)

[479] *See, e.g.,* Allegheny, EME, United Illuminating, EPSA, SMUD, Los Angeles, NASUCA, CSU.

[480] Other commenters emphasize the need for significant investments to expand transmission capacity. *See, e.g.,* EPRI, Salomon Smith Barney.

[481] *See, e.g.,* Transmission ISO Participants, SoCal Edison, H.Q. Energy Services, LIPA, NWCC.

[482] *See, e.g.,* Professor Hogan, PJM, NERA, Sithe, Allegheny, Mid-Atlantic Commissions, DOE, Duke, United Illuminating, EME.

enables market participants to pay known, fixed transmission rates and to hedge against congestion charges.

The FTC believes that accurate LMP signals for investment to reduce congestion may become even more important as distributed generation presents opportunities for small-scale, fine-tuned (with respect to both size and location) generation investments to relieve transmission congestion, in place of large-scale transmission or generation investments. EME endorses the LMP pricing approach adopted by PJM and the New York ISO, and states that the Midwest ISO and the Alliance RTO should be encouraged to adopt similar approaches. The CalPX notes that the separation of the CalPX and the ISO in California does not prevent the use of a locational pricing model that incorporates the individual buses and transmission lines in the network.

Allegheny believes that ''[c]onsistent locational marginal price dislocations readily identify system expansion, or other congestion relief, requirements as well as serve as an indicator of the most economic fix to congestion patterns over time.'' It claims that there would be no incentives for the RTO or transmission owners to maintain congestion, since there is no financial impact on them from LMP because any excess payments received by the RTO during congestion are returned to holders of FTRs. Allegheny recommends that the Commission remain flexible in considering other pricing innovations for congestion management, but believes that a simplified locational marginal pricing methodology should be established as a default market mechanism against which other pricing innovations are evaluated.

Some commenters, however, criticize the locational marginal pricing approach to congestion management.[483] APX argues that, because LMP requires the RTO to implement a centrally optimized dispatch, it will discourage, if not eliminate, the commitment of forward contracts in the energy market and replace the price discovery of forward markets with ex post pricing. APX contends that because LMP price calculations occur only periodically and in a single iteration, price visibility is restricted compared to a continuous forward market. APX claims that this diminished visibility can make the result less efficient and more vulnerable to an exercise of market power. APX contends that, for most industries, a process of continuous trading creates efficiency in a competitive market, while the LMP optimization process has no role for trading. APX asserts that no competitive industry uses optimization to simulate and substitute for market outcomes. APX contends that under LMP, the system operator, not the market, will specify the structure of the optimization problem. APX claims that markets process information much more flexibly and comprehensively through the self-interested trading behavior of buyers and sellers. APX asserts that this is the strength of markets and the critical shortcoming of LMP.

Dynegy claims that markets for FTRs have yet to fulfill their promise to provide market participants with critically important price certainty for their transmission transactions. For example, Dynegy states that allocation problems still exist, in that only a small portion of available FTRs is being auctioned off in certain markets while a large number are being withheld for incumbents' use. Dynegy argues that in order for FTRs to provide a truly effective hedge against transmission price increases resulting from LMP in the hourly market, hourly FTRs would have to be available in a liquid market at a moment's notice, but nothing close to such a market exists. Dynegy suggests that, because the LMP model has yet to be implemented successfully due to the lack of a liquid FTR market, the time is ripe to look at other models, such as a physical rights model.

LIPA claims that neither the opportunity to obtain fixed transmission rights nor the prospect of locational price reductions are sufficient to encourage efficient generation and transmission expansions. For example, LIPA notes that awarding a transmission expander transmission rights that entitle it to collect congestion rents on the expanded capacity creates an incentive that runs counter to the purpose of the expansion; *i.e.,* the more successful the expansion is in eliminating congestion, the less value the incentive has for the expander. Also, LIPA believes that locational pricing systems are biased toward using generation to solve congestion problems on the transmission grid and, as a result, could lead to market power abuse by an operator that sites a new generator in a load pocket and then takes advantage of transmission limitations to manipulate the operation of other generators that it owns.

The Virginia Commission claims that pricing mechanisms incorporating locational marginal prices tend to produce intense signals over short time frames, particularly when constraints are seasonal and driven by extraordinary events such as extreme weather. The Virginia Commission therefore believes that, at least initially, locational marginal prices may provide incentives for short-term actions for congestion relief, rather than longer term solutions such as the construction of additional transmission or generating facilities in a particular location.[484] The Virginia Commission also states that the use of locational marginal pricing is heavily dependent on the existence of transparent short-term competitive power markets. It urges the Commission to evaluate carefully proposals that place greater reliance on market mechanisms through the use of price signals, and to condition the use of such mechanisms on the existence of such things as fully functioning power exchanges, the establishment of fixed transmission rights and the existence of secondary markets for such rights.

CP&L argues that while the proposed congestion management rule appears to permit only PJM-redispatch types of arrangements, CP&L does not believe that the PJM model is the only workable congestion management process. Rather, CP&L believes that congestion is best managed through the coordinated reservation and scheduling of transactions on the grid rather than post-congestion fixes. Also, TDU Systems states that it may be difficult to transplant the PJM model to regions that do not have a centrally dispatched, tight power pool to use as an RTO platform.

Some commenters claim that LMP is more complex than necessary,[485] although Allegheny believes that today's technology mitigates these concerns. The FTC states that, despite the apparent virtues of LMP, it may be reasonable to back away from a full application of an LMP approach if doing so provides benefits to consumers from increased competition in generation markets. For example, the FTC states that, in light of its alleged complexity and the difficulty that financial markets may have in anticipating congestion charges, LMP may inhibit the formation of efficiency-enhancing futures markets in electricity generation and trading because congestion prices are more uncertain under LMP than under other pricing approaches (such as zonal transmission congestion pricing). The FTC thus suggests that the Commission may want to continue to entertain alternatives to LMP if a reasonable case is made that benefits to consumers are

[483] *See, e.g.,* APX, LIPA, TDU Systems, CP&L, Virginia Commission, Tri-State, Dynegy.

[484] The Brattle Group believes that, in addition to locational congestion pricing, some form of regulatory incentives may be needed to bring about efficient investment in the transmission grid.

[485] *See, e.g.,* PG&E, PJM/NEPOOL Customers, FTC, Tri-State, Dynegy.

greater under the alternatives than under LMP.

Managing Congestion with Tradable Transmission Rights. Several commenters emphasize the importance of including explicit transmission rights in any congestion management plan that relies on market mechanisms.[486] EPSA believes that when transmission rights are clearly defined and allocated, ATC calculations can be made more accurately and congestion management simplified. DOE notes that financial transmission rights will provide a hedge against long-term fluctuations in spot prices, will encourage the development of competitive markets and will likely contribute to efficient generation and transmission resource planning. SMUD emphasizes that, without the pricing hedge provided by such rights, it cannot guarantee its customer-owners low cost or reliable transmission service.

A number of commenters emphasize that transmission rights must be tradeable in a secondary market.[487] Indeed, some commenters believe that the use of firm (physical) transmission rights along with a robust secondary market in these rights is the most workable solution for efficient congestion management.[488] Seattle notes that with an effective market for transmission rights, market participants may be afforded transmission-based options for resolving congestion. It states that market participants that invest in transmission facilities that increase capacity can receive the right to use or sell that capacity. Enron/APX/Coral Power believes that the RTO should be charged with developing a workable market approach to congestion and parallel-path management based on clear and tradeable rights for transmission usage that promote efficient regional dispatch, and support the emergence of secondary markets for transmission rights. Enron/APX/Coral Power contends that this will require that RTO systems be operated as they are in the Western Interconnection based on physical rights. It suggests that, in order to ensure a firm right to schedule service over an interface when it is constrained, a customer would have to demonstrate ownership of sufficient property rights in the interface. Enron/APX/Coral Power suggests three options for obtaining rights: (1) From the RTO in the primary auction or other primary form of allocation; (2) from holders of rights in the secondary market; and (3) from the RTO in the form of short-term released rights not scheduled by their holders. Enron/APX/Coral Power states that by defining and enhancing physical property rights, the market for those rights will provide *ex ante* transmission prices that include the cost of purchasing rights in constrained interfaces. It claims that this will permit dispatch decisions to be made on the basis of delivered energy prices. Enron/APX/Coral Power states that to ensure that no market participant can exercise market power by hoarding property rights, the rights should be designed as use-or-lose so that if a right is not scheduled it can be used by others on a non-firm basis.

Similarly, Dynegy proposes a physical rights model in which a limited amount of firm physical rights would be sold and only those holding physical rights would be allowed to schedule when capacity is constrained. Under Dynegy's proposal, only those with preassigned FTRs would be allowed to schedule on a firm basis at a set price. Dynegy states that others could submit non-firm schedules, subject to curtailment, or, if the party is willing, redispatch. Dynegy adds that the proponents of rights that are financial only argue that it is impossible to define physical rights as ''100 percent firm'' from a given source to a given sink. Dynegy states that, while such arguments are convincing, the capacity between a source and sink may actually be available for a significant percentage of the time to a reasonable degree of certainty and, accordingly, could be sold as firm.

APX states that the definition of transmission property rights requires the calculation of stable power distribution factors that show the proportion of a power transaction that flows over each path on the grid connecting the source-sink pair. It states that after defining the property rights, the RTO can conduct an auction to allocate them. APX states that, following the auction, holders of transmission rights can retain them or trade them in a secondary forward market. APX believes that FTR trading will provide a more direct and comprehensive valuation of rights than LMP. Desert STAR states that it plans to rely on firm transmission rights markets as the primary vehicle for managing commercially significant congestion, and the use of incremental/decremental generation bids to manage other congestion.

Other commenters, however, doubt that a system of physical transmission rights can be used effectively to manage congestion.[489] NERA states that most commodity markets operate according to a process based on physical contracts or rights traded in decentralized markets separated from physical operations. NERA adds, however, that most commodities do not flow on an integrated grid where network externalities are so strong and complex that a monopoly system operator is needed. NERA argues that network externalities on any complex electricity grid make it virtually impossible to define physical transmission rights that will use the system fully and yet can be traded in decentralized markets. Also, Professor Joskow believes that on complex electric power networks with loop flow, a financial rights system can be designed more easily and can work more smoothly and efficiently than can a physical rights system.[490]

Some commenters offer additional notes of caution regarding the use of transmission rights. For example, APPA states that one must guard against market participants using transmission rights to act strategically. APPA argues that if a generator can adversely affect transfer capability, it may seek to purchase and resell transmission rights in the secondary market after manipulating its internal operations to create congestion on the grid. RECA considers proposals that allow customers to purchase long-term rights to mitigate the risk of congestion pricing to be unacceptable because such proposals result in long-term firm customers having to pay a premium for price stability. Also, CSU contends that no party should hold any entitlement over a constrained path due to transmission ownership which predates the formation of the RTO. CSU argues that, because all parties dedicating bulk transmission assets to the RTO will be fully compensated for their embedded costs, there should exist no reserved rights of use other than those purchased from the RTO. In addition, Great River is concerned that the NOPR's proposal regarding the establishment of clear and tradable transmission rights is not consistent with the flexibility that transmission customers currently have under network service. Great River urges the Commission to carefully consider congestion management proposals that preserve network-like

[486] *See, e.g.,* PJM, SMUD, DOE, Enron/APX/Coral Power, EPSA, NSP, Seattle, Professor Hogan, EME.

[487] *See, e.g.,* DOE, NSP, Enron/APX/Coral Power, Seattle, Nevada Commission.

[488] *See, e.g.,* APX, Enron/APX/Coral Power, Tri-State, Desert STAR.

[489] *See, e.g.,* NERA, Professor Joskow, Allegheny.

[490] Professor Joskow notes that Enron/APX/Coral Power claims that two unpublished papers he has co-authored with Jean Tirole conclude that physical rights designed on a use-it-or-lose-it basis (so that they cannot be hoarded) more effectively prevent the exercise of market power than financial rights, which can always be hoarded. He states that this is not what the papers conclude.

service, even if such proposals do not result in the identification of asset-based transmission rights.

Other Mechanisms for Managing Congestion. Some commenters support yet other market mechanisms for managing congestion.[491] EPSA notes that other pricing approaches that deserve consideration include the RTO's use of supply-side bids to relieve congestion in load pockets, as well as the use of bilateral arrangements to solve congestion problems. Also, NSP recommends that the RTO offer a ''firming'' service, at posted rates, that would provide customers with the assurance that their transaction will occur under most curtailment conditions. In addition, NSP proposes that the RTO offer a real-time redispatch service that will allow transmission customers to buy through congestion at real-time prices. Cal ISO notes that the Commission has accepted its zonal approach to congestion management, which relies on market mechanisms to manage inter-zonal congestion. PG&E claims, however, that while providing a more understandable picture of congestion, such a system must still solve the problem of intra-zonal congestion. Also, the Montana Commission recommends that the congestion management regime that was developed as a part of the IndeGO proposal serve as a model for how to manage congestion on the transmission system. However, Avista claims that the IndeGo proposal proved to be too complicated to solve a problem that exists only on a few select transmission paths in the Pacific Northwest.

Costs and Revenues in Congestion Management. A number of commenters urge the Commission to pay close attention to issues related to the distribution of the costs and revenues of congestion management among market participants.[492] In particular, several commenters caution that congestion pricing mechanisms should ensure that congestion costs are fairly allocated and should not result in excessive revenues or monopoly profits for transmission owners.[493] APPA states that only after we have a nationwide framework of truly independent RTOs should the Commission consider a new approach to transmission pricing that would allow the RTO to price transmission capacity rights and usage on congested paths above embedded costs while discounting uncongested paths below embedded costs, subject to a balancing account to ensure that the total transmission revenue requirement is not over-recovered.

Similarly, TDU Systems believe that while the formation of RTOs is a unique opportunity to experiment with new forms of transmission pricing, the Commission should be mindful that an RTO will be a large regional transmission monopoly. TDU Systems question the wisdom of designing congestion pricing mechanisms to ensure that limited transmission capacity is used by market participants who value that use most highly. It states that such an auction-to-the-highest-bidder approach could reap monopoly rents for transmission providers, at the expense of consumers. TDU Systems thus argues that over-reliance on economic self-interest and market mechanisms in transmission pricing may become a recipe for new forms of undue discrimination. It suggests that an incentive to avoid expanding the system in order to collect monopoly rents can be removed by placing any excess revenues from congestion pricing in a fund earmarked for transmission system expansion.

TDU Systems also recommends that the Commission encourage congestion management plans that distinguish between congestion caused by the RTO's obligation to provide service to firm transmission customers, and congestion caused for economic reasons. It argues that, in the case of the former, the costs of relieving the congestion should be averaged over the firm RTO transmission customers that are using its system. However, it claims that economic congestion occurs because market participants wish to take advantage of short-term production cost economies to minimize their power costs. In this case, TDU Systems argues that the specific loads purchasing the generation should pay the associated congestion costs. Also, RECA states that long-term firm transmission customers are the ones that use and pay to support the system throughout the year, but the auction approach allows a short term trader to outbid these customers at the very times they need it most. Enron/APX/Coral Power notes that, if the RTO's regulated rates for transmission service, including congestion management, are properly designed to reward the RTO for cutting operating costs and maximizing throughput, then it would not have to assign the grid expansion costs to new generators that interconnect. Instead, the RTO would charge the new generator only the cost of local interconnection with the grid.

Dynegy claims that, with respect to each transmission provider's system, there is a predictable level of constraints and, similarly, some representative level of costs associated with relieving those constraints. Dynegy believes that such costs should be rolled into firm transmission rates that can be quoted up front and with certainty. Dynegy argues that transmission providers would have an economic incentive to operate their transmission systems efficiently if they are given an uplift cost target, and are rewarded for beating the target and penalized for exceeding the target. EPSA states that some congestion pricing mechanisms can impose potentially huge costs on individual transactions, which can be detrimental to the goal of fostering wholesale competition. EPSA thus urges the Commission to consider whether these pricing mechanisms provide greater benefits than a system that internalizes more of the congestion costs. Indeed, EPSA argues that it is still appropriate to spread many of those costs to all system users because redispatch generally benefits all users of the transmission system.

NCPA asserts that, in order to prevent large increases in the cost of generation for customers in congested areas, some non-discriminatory way must be found to return the extra revenues collected to those customers. NCPA believes that this will require restructuring of tariffs, but failure to address the problem is likely to keep utilities with customers in congested areas out of the California ISO. Similarly, the South Carolina Authority is concerned that certain centralized market mechanisms would cause cost shifts for those participating in an RTO, and if so, potential participants opt out. Also, the Wyoming Commission is concerned that, by offering rewards for transmission investment such as a higher return on equity, the Commission would effectively be discouraging a more market-oriented review of alternatives to building transmission to solve congestion problems.

Some commenters emphasize the importance of ensuring full cost recovery for generators that are redispatched by an RTO to alleviate transmission constraints or to provide other support services.[494] NERC contends there must not be disincentives, in the form of unrecovered costs, to having generators perform these vital functions. MidAmerican asserts that optimal dispatch will occur during congestion management as long as all power suppliers are fully compensated at

[491] *See, e.g.*, Cal ISO, Montana Commission.

[492] *See, e.g.*, TDU Systems, NCPA, Los Angeles, Wyoming Commission, SMUD, South Carolina Authority.

[493] *See, e.g.*, APPA, RECA, TDU Systems, Los Angeles, EPSA.

[494] *See, e.g.*, Allegheny, Platte River, NERC.

market prices. Cinergy claims that, unless generators have the ability to recover lost revenues for reducing generation in response to congestion management needs, generators have no incentive to follow dispatch orders. SMUD contends that the Commission needs to develop congestion management principles that ensure that market participants will receive fair market value for facilities that they have owned and operated for many years.

Importance of Scale in Congestion Management. A number of commenters argue that the achievement of an appropriate scale by an RTO will be important to the effective management of congestion.[495] LG&E states that the Commission should require RTOs to be of sufficient size to be capable of meaningfully addressing congestion. It believes that if a proposed RTO's ability to address congestion would be impaired by its size or configuration, then the Commission should either refuse the RTO's application or should condition approval on attaining the necessary size and configuration to manage regional congestion issues. Industrial Consumers state that, although congestion management can be addressed with non-market solutions such as transmission loading relief procedures, it is far better to internalize the problem within an RTO with an appropriate scope and configuration. Minnesota Power notes that, currently, it can have transactions curtailed by two different procedures, NERC Transmission Loading Relief and MAPP Line Loading Relief. It claims that an RTO will provide transmission users with region-wide, standard, congestion management.

The Midwest ISO states that an appropriately sized RTO will be able to relieve congestion on a broad scale. However, it claims that its own redispatch options will be limited by the failure of border companies, such as FirstEnergy and AEP, to join it. Also, it notes that longer term congestion relief involves the construction of transmission facilities. It claims that, if border companies are not members, the Midwest ISO will not have the ability to coordinate required transmission construction by those entities. Also, the Midwest ISO Participants state that new transmission facilities required to relieve constraints may involve both the companies of the Alliance RTO and the Midwest ISO Participants. The Midwest ISO Participants believe that, with planning and authority split between these two regional entities, these facilities may not be optimally constructed or located.

Ontario Power, however, takes a different view. It claims that many of the advantages that would flow from expanding U.S. markets to include Ontario can be realized without requiring the Independent Electricity Market Operator (IMO) in Ontario to join a larger RTO at this time. Ontario Power believes that these advantages could be achieved by negotiating agreements between the IMO and other RTOs. Also, Central Maine states that if transmission line loading relief is performed on a market basis, many of the benefits that might result from merging existing ISOs could be realized without actually requiring those ISOs to merge.

Tri-State argues that the Commission should provide an incentive for non-participating transmission owners to join an RTO by allowing the RTO to use a pricing and congestion management structure that withholds the benefits of the RTO from entities that refuse to turn control of their transmission assets over to the RTO. Also, Vernon claims that non-participants can take unfair advantage of ISO-controlled facilities by scheduling their own loads over ISO grid facilities that parallel the non-participant paths, instead of scheduling them over their own wires. Vernon contends that having thus freed up their own wires, the non-participants can then put their facilities to various uses, such as to avoid the increased ISO grid congestion.

Congestion Management Between RTOs. Many commenters believe that effective congestion management must take into account effects that extend beyond the RTO's boundaries.[496] NERC states that congestion management approaches that work within a particular region may not adequately deal with transactions that originate or terminate outside the region. NERC believes that as RTOs develop congestion management approaches, the Commission must require that they be compatible with what is happening elsewhere.

Industrial Consumers believe that congestion management, especially during emergency conditions, is an interconnection-wide responsibility. It asserts that, if multiple RTOs are allowed within an interconnection, congestion management must be coordinated across RTO boundaries. Industrial Consumers argues that an RTO can accomplish this only by sharing data on system conditions (*e.g.,* ATC calculations) with neighboring RTOs, agreeing to protocols for cross-boundary actions to mitigate congestion, and cooperating in a process to ensure fair compensation to generators that are redispatched.

UAMPS believes that if a state is involved in the consideration of various potential solutions to regional congestion, it will likely be more willing to accept that a particular proposal to construct new transmission within its borders is indeed the most efficient solution to a genuine problem, and to provide the necessary approvals for that construction.

Transcos and Congestion Management. Some commenters are concerned that, if a for-profit company owns transmission (*e.g.*, a transco), it may not have the correct incentives to manage congestion efficiently.[497] ISO–NE argues that if such a company seeks to operate transmission and markets as an RTO, it will have competing responsibilities and economic interests. ISO–NE believes that, given the company's economic motivations, market participants may have insufficient confidence in such a company's determinations of whether a transmission-expansion solution to congestion is preferable to a generation-based solution. EAL believes that compensating a wire-owning RTO on the basis of invested capital could lead to over-building of transmission. New Smyrna Beach is concerned that a for-profit transmission company will exhibit a bias toward transmission construction when other, more economical alternatives might exist. New Smyrna Beach states that the Commission should consider requiring the RTO to conduct a competitive bidding process when it determines that transmission construction, or an alternative, is needed to relieve transmission constraints.

Industrial Consumers asserts that transcos would compete head-on with generation companies wherever there is congestion. It thus believes that transcos-as-RTOs would have a serious conflict of interest if they have the authority over congestion management and over the decision whether to eliminate congestion with new generation or transmission facilities. Industrial Consumers believes that where new generation is a more cost-effective option than construction of new transmission facilities, the cheaper option should be built, and markets should be given the opportunity to make

[495] *See, e.g.*, LG&E, ComEd, Midwest ISO Participants, Midwest ISO.

[496] *See, e.g.*, NERC, Mass Companies, Industrial Consumers, Montana Commission, Indiana Commission, AEP.

[497] *See, e.g.*, ISO-NE, EAL, New Smyrna Beach, Industrial Consumers.

the choice. Industrial Consumers believes, however, that this will require that the markets have access to redispatch costs, congestion valuations (from a secondary market for capacity reservations), and other data on grid conditions. This is information that is better disclosed by a disinterested independent RTO than a self-interested transco or generation company.

Cal DWR questions whether either ISOs or transcos have an incentive to use transmission alternatives (such as demand-side management, load shedding, distributed generation, or generation) to reduce the overall cost of transmission. However, it believes that this problem may be more acute for a transco, for which revenues and return are directly tied to the use of their transmission assets.

However, other commenters claim that there is no basis for concerns that a transco will favor a transmission solution to constraints.[498] Entergy contends that, if a generation solution is the most efficient way to resolve congestion, a new generator will likely realize that and try to locate in the appropriate area. Entergy states that an RTO's obligations as an open access transmission provider leave it with no choice but to interconnect with the new generator. Also, Entergy argues that an RTO will not have the unfettered ability to propose and build inefficient transmission solutions. It believes that review by state regulators with siting authority, and prudence review by the Commission, will make it difficult for an RTO to build inefficient and unnecessary transmission additions. Enron/APX/Coral Power and JEA believe that a transco may, in fact, be well suited for congestion management. Enron/APX/Coral Power states that placing responsibility for managing congestion in the RTO's hands complements their view that an RTO-Transco must be obligated to assume delivery risk (*i.e.*, deliver physically firm power) in exchange for being rewarded for cutting costs and increasing system throughput.

The Need for Flexibility in the Design of Market Mechanisms. Commenters in general showed considerable support for the NOPR's proposal to give RTOs considerable flexibility in experimenting with different market approaches to managing congestion.[499] Mass Companies state that the NOPR's willingness to allow RTOs latitude to develop local approaches to congestion management is particularly appropriate, given the difference in conditions in different parts of the country. CP&L believes that congestion management is an area where a one-size-fits-all solution would miss the mark and unnecessarily increase the cost of forming and operating an RTO. SRP believes that a flexible approach is needed because the use of market mechanisms for congestion management is in its infancy, and poorly designed market mechanisms can exacerbate problems and adversely impact reliability.

The Florida Commission states that the details of proposals for managing congestion using a market mechanism should be determined on a regional basis with endorsement by the state regulatory body. The Florida Commission recommends that the Commission continue to monitor discussions of these issues within NERC and not duplicate or foreclose their development and resolution at NERC.

Montana-Dakota recommends that the Commission not limit the experimentation with market mechanisms to the provision of firm transmission service. Montana-Dakota believes that there is potential to further improve transmission services by allowing RTOs the ability to implement congestion management methods for non-firm services rather than relying only on the use of TLR to curtail such services.

Many commenters express support for the proposal to allow RTOs flexibility in developing approaches to congestion pricing.[500] Some, such as Florida Power Corp. and Desert STAR, believe that allowing flexibility in pricing may provide incentives for transmission owners to join or form an RTO. Florida Power Corp. argues that such flexibility allows transmission owners to deal with issues such as cost shifting, and believes that providing more specific guidance will only limit possible options.

However, the FTC cautions that the Commission should not allow its policy of flexibility to continue indefinitely. The FTC states that although experimentation with transmission congestion pricing alternatives to LMP may be appropriate at present, it does not believe that great uncertainty about the most effective approach to transmission congestion management need exist indefinitely. It suggests that the Commission may wish to establish a date in the not-too-distant future when it will undertake a comparative analysis of the consumer costs and benefits of alternative transmission pricing regimes. The FTC states that if one or more approaches provide substantially superior results for consumers, the Commission may wish to initiate a rulemaking on policies to encourage RTOs to adopt these approaches. The Oregon Commission recommends that the Commission evaluate the effectiveness and efficiency of various congestion pricing experiments, and based on its evaluation, require RTOs to use the better methods. However, the Oregon Commission estimates that the process of refining congestion pricing methods may take a decade or more.

NERC states that there are strongly held, differing opinions throughout the industry on how congestion prices should be designed. NERC states that, while flexibility is one important consideration, the various regional solutions must be able to work together. It believes that the Commission can provide the leadership needed to bring the industry to closure on these issues. NERC notes that this may require the Commission to be more proscriptive, and it should not hesitate to do so. In this regard, Minnesota Power suggests that the Commission encourage neighboring RTOs with constrained interfaces to jointly develop constraint relief procedures including common constraint pricing where appropriate.

Timing of Implementation.With regard to the NOPR's proposal to allow RTO's up to one year after start-up to implement the congestion management function, commenters express a variety of opinions. Some indicate that one year is an appropriate additional time period.[501] Others, however, believe that it is essential that the RTO have some form of congestion management system in place when it begins operation.[502] SMUD and CMUA state that a significant deterrent to participating in the Cal ISO has been the fact that, in California, Cal ISO transmission is strictly a short-term transaction given that Cal ISO has not yet fully implemented FTRs. SMUD emphasizes that, without the hedge provided by FTRs, it cannot guarantee its customer-owners low cost or reliable transmission service. TANC believes that allowing an RTO to begin operations without a congestion management procedure in place greatly increases the opportunity for market power abuses as well as market inefficiency.

[498] *See, e.g.*, Trans-Elect, FirstEnergy, Entergy.

[499] *See, e.g.*, Mass Companies, SRP, CP&L, Southern Comany, PJM/NEPOOL Customers, United Illuminating, Georgia Commission, JEA, Florida Commission, NYPP, Cinergy.

[500] *See, e.g.,* PJM/NEPOOL Customers, United Illuminating, Florida Power Corp., Desert STAR, Oregon Commission, NERC.

[501] *See, e.g.,* Industrial Consumers, Allegheny, PGE, Entergy.

[502] *See, e.g.,* SMUD, Tri-State, CMUA, TANC, Desert STAR, Cinergy.

Duke states that, ideally, the permanent congestion management function should be in place on the first day of RTO operation. Then, Duke notes, it would not be necessary to incur the cost of implementing, and developing strategies and behavior appropriate to an initial system, only to have to incur additional costs and changes in behavior to adapt to a permanent system. However, Duke states that congestion management issues are complex and substantial information management systems must be put in place. Consequently, Duke believes one year from the time the RTO becomes operational may not be a sufficient length of time to implement the congestion management function.

Desert STAR states that the new approaches to congestion management called for by newly competitive markets will take additional time to work out and, therefore, the Commission should be willing to consider additional time on a case-by-case basis. However, in order to ensure reliable operation, Desert STAR believes some congestion management system must be in place when the RTO begins operation.

Some commenters believe that more than one year of additional time may be needed for the RTO to implement the congestion management function. NSP states that if the RTO has a state-estimator model with the necessary properties, it is possible that a congestion management system, of the type preferred by NSP, could be implemented within about 18 months from the time of project initiation. However, for regions without the necessary models, NSP expects the time-line would likely be three years from time of project initiation.

Montana Power believes that there will be many ''growing pains'' associated with implementation of RTOs that will take time to work out, especially in areas like the Pacific Northwest, which have no history of tight pool operation. Montana Power believes that allowing one-year for implementing a market mechanism for congestion management is a very aggressive schedule. Montana Power thus encourages the Commission to allow up to three years. Similarly, Avista states that, with the IndeGo experience in mind, it encourages the Commission to allow two to three years for implementation of this function, especially where it is demonstrated that the RTO will comply immediately with other characteristics and functions identified in the Commission's Final Rule.

The Florida Commission believes that the Commission should not impose any arbitrary time period for implementation of congestion management. It states that NERC is working with the regions on this issue and FERC should monitor those activities before setting any deadlines, if at all. Also, JEA believes that requiring the congestion management function to be in place within one year from the start-up of RTO operation may be feasible only for those RTOs structured as transcos from the beginning.

Commission Conclusion. As we proposed in the NOPR, we conclude that an RTO must ensure the development and operation of market mechanisms to manage congestion. Furthermore, as we proposed, we will require that responsibility for operating these market mechanisms reside either with the RTO itself or with an another entity that is not affiliated with any market participant.

We agree with the large number of commenters that believe that the use of market mechanisms to manage congestion is superior to the use of administrative curtailment procedures or other approaches that do not take into account the relative value of transactions that are curtailed and those that are allowed to go forward. In addition, we conclude that the RTO or an independent entity must assume an active role in developing and implementing any congestion market mechanisms, because the use of such mechanisms must necessarily be closely coordinated with the operational activities that the RTO performs on a day-to-day and, in many cases, moment-to-moment basis.

Some commenters argue that an RTO should not be allowed to operate a centralized market for congestion management. The commenters contend that, if such a market is operated by an RTO or other entity that is independent of the market, a robust market in forward contracts for energy will not develop. As a result, these commenters claim, society will never obtain the efficiency benefits that would otherwise flow from a marketplace in which buyers and sellers are able to trade actively among themselves. These commenters also argue that the price certainty provided by forward markets will be replaced with the uncertainty of prices that are determined after the fact.

We disagree with these commenters and see no reason why the RTO's operation of a market for congestion management should inhibit the ability of others to offer forward contracts for energy, or other market instruments that provide price certainty. We recognize that some of the market redispatch programs undertaken to date are experimenting with various ways to manage congestion efficiently-including relying upon decentralized markets to effect the necessary redispatch.[503] It is too early to tell if these decentralized markets will work efficiently. But given the short time frame in which system operators often must react to congestion situations, experience may ultimately show that markets for congestion management can achieve more efficient and effective results if they are centrally operated. Therefore, we will not deny here the RTO, or other independent entity, the opportunity to operate a market—either centralized or de-centralized—for congestion management.

As we proposed in the NOPR, we will require the RTO to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions. We are convinced that efficient congestion management requires that transmission customers be made aware of the cost consequences of their actions in an accurate and timely manner, and we believe that this is best accomplished through such a market mechanism. Also, as we proposed in the NOPR, we believe that congestion pricing proposals should seek to ensure that (1) the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and (2) limited transmission capacity is used by market participants that value that use most highly. Although we agree with some commenters that price signals can also assist in determining the efficient size and location of new generation and grid expansions, we share the view of LIPA and others that price signals alone cannot be relied upon to identify all needed enhancements.

While we will not prescribe a specific congestion pricing mechanism, we note that some approaches appear to offer more promise than others. As we stated in our order approving the PJM ISO and reiterated in the NOPR, markets that are based on locational marginal pricing and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management.[504] A number of commenters express strong support for the LMP approach. As PJM notes in its comments, LMP assesses congestion charges directly to transmission customers in a manner consistent with

[503] *See, e.g.,* the market redispatch experiment of NERC (Docket No. ER99–2012–000).

[504] *See PJM,* 81 FERC at 62,252–53.

each customer's actual use of the system and the actual dispatch that its transactions cause. In addition, LMP facilitates the creation of financial transmission rights, which enable customers to pay known transmission rates and to hedge against congestion charges. We further note that, where financial rights holders are entitled to receive a share of congestion revenues, the availability of such rights helps to address the concerns of commenters who fear that congestion pricing can lead to the over-recovery of transmission costs. The Commission recognizes, however, that LMP can be costly and difficult to implement, particularly by entities that have not previously operated as tight power pools.

The principal alternative to LMP advocated by commenters is an approach that manages congestion by means of physical transmission rights that are tradable in a secondary market. Under this approach, the RTO may be required to issue the transmission rights initially through an auction or allocation process. Market participants would then generally have to demonstrate ownership of sufficient rights in a constrained interface before they would be allowed to schedule firm service over the interface. Such an approach greatly reduces the role of the RTO in congestion management. While the approach of trading physical transmission rights in a secondary market may prove to be workable in regions where congestion is minor or infrequent, in other regions where congestion is more of a chronic problem, it may not be workable. Also, commenters such as NERA and Professor Hogan claim that the network interactions on complex electricity grids make it difficult to define physical transmission rights that will use the system fully and yet can be traded in decentralized markets. We expect RTOs and any affected stakeholders to consider carefully such issues as they formulate specific pricing proposals.

While our experience has shown that, in specific situations, some approaches to congestion pricing appear to have advantages over others, we have not yet identified one approach as being clearly superior to all others. Furthermore, the Commission recognizes that an RTO's choice of a congestion pricing method will depend on a variety of factors, many of which may be unique to that RTO. Therefore, we will allow RTOs considerable flexibility to propose a congestion pricing method that is best suited to each RTO's individual circumstances.

Some commenters appear to confuse the need to redispatch generators to maintain reliability with the need to take specific actions to relieve congestion. Commenters generally agree that the RTO should have clear authority to order redispatch for reliability purposes. However, for congestion management, we conclude here that the RTO should attempt to rely on market mechanisms to the maximum extent practicable. We recognize, of course, that there may be times when even well-functioning markets will fail to provide the RTO with the options it needs to alleviate a specific instance of congestion. In those cases, the RTO must have the authority to curtail one or more transmission service transactions that are contributing to the congestion. Although the act of curtailing a transaction may sometimes require the redispatch of generation, we clarify that we are not requiring the RTO to redispatch any generators exclusively for the purpose of managing congestion.

In the NOPR, we stated that a workable market approach to congestion management should establish clear and tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices. Most commenters agree that these are reasonable features of any congestion management proposal. However, Enron/APX/Coral Power believes that the RTO should not be allowed to provide a hedging instrument. It contends that the ''monopoly wires business'' should not be allowed to encroach on what it views as the highly competitive and innovative business of providing hedges against locational price differences of energy or capacity, or against price volatility of these or any other competitive products. In response, we note that, while decentralized markets may ultimately prove to be capable of providing such products, as these commenters claim, we do not yet have evidence to that effect. Therefore, in the interest of allowing RTOs flexibility to experiment with different market approaches, we will not prohibit the RTO from offering such products through markets that it may operate.

Finally, with regard to the timing of implementation of the congestion management function, we will adopt our proposal to allow the RTO to take up to one year after start-up to implement market mechanisms for managing congestion. Most commenters agree that some period of time is needed for implementation. However, a number of them indicate that the RTO must have some form of congestion management system in place when it begins operation. We agree, and clarify that, upon start-up, the RTO must have in place effective protocols for managing congestion while preserving reliability. Because the NOPR did not make this point explicitly, we do so here.

3. Parallel Path Flow (Function 3)

In the NOPR, the Commission proposed to require that an RTO develop and implement procedures to address parallel path flow issues within its region and with other regions.[505] The Commission noted that measures to address parallel path flow between regions may not necessarily be in place on the first day of RTO operation, and proposed to allow up to three years after start-up for this function to be implemented.[506] The Commission sought comments on whether such an additional implementation time period is warranted, and whether three years is an appropriate additional time period.

Comments. Virtually all commenters support the NOPR's proposal to require that an RTO develop and implement procedures to address parallel path flow issues as a separate function.[507] Industrial Consumers states that parallel path flow-related disputes will diminish as a result of RTOs addressing this issue.[508] But PGE notes that grandfathering existing transmission contracts may impede the RTO's ability to address loop flow.

Many commenters assert that parallel path flow and congestion management issues are closely related to one another since both the issues involve identification of power flows resulting from a specific transaction.[509] Therefore, they argue that any solution to parallel path flow should recognize

[505] The terms ''parallel path flow'' and ''loop flow'' are sometimes used interchangeably to refer to the unscheduled transmission flows that occur on adjoining transmission systems when power is transferred in an interconnected electrical system.

[506] FERC Stats. and Regs. ¶ 32,541 at 33,743–44.

[507] *See, e.g.,* ComEd, East Texas Cooperatives, EPSA, Industrial Consumers, LG&E, NASUCA, NSP, PJM, Southern Company and Williams. However, Cinergy argues that parallel path flows should not be considered as a separate function but should be considered as a characteristic under the scope and regional configuration because that will allow an RTO to address congestion management issues along with parallel path issues.

[508] Industrial Consumers also notes that the first sentence in the proposed regulation should be modified to read as ''RTO must develop and implement procedures to address parallel path flow issues within its region and with other regions *in the interconnection within which it resides.''* (Suggested change underlined)

[509] *See, e.g.,* EPSA, Florida Power Corp., FTC, Georgia Transmission, LG&E, Mass Companies, NSP and PJM.

this close relationship. For example, Industrial Consumers believes that an RTO can take preemptive actions against potential curtailment situations to manage congestion resulting from loading of chronically constrained transmission interfaces due to loop flow. PJM suggests that the use of redispatch solutions like LMP not only is more efficient and beneficial to a competitive market, but is preferable to curtailing transactions under TLR to address congestion due to loop flow. South Carolina Authority is convinced that over the long run the problem of parallel path flow needs to be addressed as a planning issue, focusing on appropriate reinforcements to constrained transmission lines.

Many commenters recommend that an RTO should encompass as large a region as possible so that it can ''internalize'' most of the loop flow within its region.[510] However, others argue that the loop flow issue can be solved satisfactorily only if it is addressed at the interconnection level.[511] They believe that while a large RTO will ''internalize'' most of the parallel path flows within its region, parallel path flows between RTOs will remain. Some other commenters are convinced that cooperative efforts among regional entities works best when it comes to resolving issues such as parallel path flow issue.[512] NERC notes that it is in the process of developing the needed information system to address the parallel path flow issue on an interconnection basis and urges the Commission to direct the RTOs to work closely with it to coordinate efforts to resolve this issue. Southern Company and Industrial Consumers support NERC's initiative in solving the loop flow issue. Cleveland states that the national grid should be viewed as a single electrical system which calls for a universal approach rather than a regional approach to resolve the loop flow issue. The universal approach, Cleveland argues, will not only improve the integrity and reliability of the national grid but also eliminate the need for any policy shift in the future.

Commenters from Western System Coordinating Council (WSCC) assert that the loop flow issue in their region was solved by the adoption of WSCC Flow Mitigation Plan (Plan) that provides for controlling unscheduled flows through the use of phase shifting transformers.[513] SRP suggests loop flow in WSCC should continue to be addressed at the WSCC level and not at the RTO level because WSCC may end up with four or more RTOs. PG&E recommends that the establishment of property rights such as FTRs be explored as a means to solve loop flow issues, on the basis that developing property rights will ensure the most efficient use of the transmission lines. Enron/APX/Coral Power urges RTOs in the Eastern Interconnection to move toward the Western model. NASUCA believes that RTOs should perform a cost-benefit analysis of controlling loop flows with phase shifting transformers.

Most commenters support the NOPR's proposal for an additional implementation time period of three years for coordination among RTOs.[514] They argue that the proper resolution of loop flow presents a number of complex issues that may require negotiations and agreements among neighboring RTOs and that the additional time period will give them an opportunity to coordinate their efforts. Allegheny supports an additional time period for implementation of this function but urges the contract path methodology be replaced at a faster pace than three years. Industrial Consumers notes that an additional time period of three years is necessary for NERC to solve the loop flow issue at the interconnection level. However, Florida Power Corp. and Florida Commission observe that the severity of parallel path flow varies from region to region and therefore opposes setting an arbitrary time limit for the implementation of this function. Duke likewise believes that the deadline for the implementation of this function should be determined by the Commission on a case-by-case basis.

Commission Conclusion. We reaffirm our preliminary determination that an RTO should develop and implement procedures to address parallel path flow issues within its region and with other regions. Most commenters agree that the formation of RTOs, with their widened geographic scope of transmission scheduling and expanded coverage of uniform transmission pricing structures, provide an opportunity to ''internalize'' most, if not all, of the effect of parallel path flow in their scheduling and pricing process within a region. NERC notes that it is in the process of developing the needed information system to address parallel path issues on an interconnection basis, and we will direct RTOs to work closely with NERC, or its successor organization, to resolve this issue. As noted by Industrial Consumers, parallel path flow-related disputes will diminish as a result of RTOs addressing this issue.

Commenters from Western System Coordinating Council (WSCC) state that they adopted the WSCC Flow Mitigation Plan (Plan) to address parallel path flow issue in their region. SRP suggests that parallel path flow in WSCC continue to be addressed at the WSCC level and not at the RTO level because WSCC may end up with more than one RTO. We will not here make any judgments on the merits of WSCC's Plan as a solution for parallel path flow issues. However, we clarify that this rule does not prevent addressing parallel path flow issues on a larger-than-single-RTO basis. In fact, we require RTOs to develop and implement procedures for addressing parallel flow issues with other regions.

In the NOPR we proposed that the RTO have measures in place on the date of initial operation to address parallel path flow issues within its own region. We also noted that measures to address parallel path flow issues between RTO regions may not necessarily be in place on the first day of RTO operation. We proposed to allow up to three years after start-up for this function to be implemented. Most commenters support the NOPR's proposal for an additional time period of three years. A few commenters [515] prefer a case-by-case approach. Since severity of the parallel path flow varies from region to region, some parts of the Nation may choose to resolve inter-regional parallel path flow issues sooner than the required three years. Consequently, we will adopt our proposal in the NOPR that the RTO have measures in place to address parallel path flow issues in its region on the date of initial operation. We also adopt three years as an adequate time period for implementation of measures to address parallel path flow issues between regions.

We recognize that these measures to address parallel path flows combined with the requirement that the RTO be the sole provider of transmission services over facilities that it owns or controls will eliminate or diminish the ability of transmission users to choose among different contract paths owned by different service providers within the

[510] *See, e.g.,* LG&E, Michigan Commission, NASUCA, New Smyrna Beach, NSP, PJM and South Carolina Authority.

[511] *See, e.g.,* Cleveland, East Texas Cooperatives, Georgia Transmission, Industrial Consumers, NY ISO, Southern Company, TEP. Industrial Consumers note that several other issues need to be addressed at the interconnection level and not at the regional level. They are ATC calculation, inadvertent flows and congestion management.

[512] Central Maine Reply at 9; NYPP Reply at 10.

[513] *See, e.g.,* PG&E, Seattle, SRP and TEP.

[514] *See, e.g.,* Cal ISO, Desert STAR, Entergy, Industrial Consumers, NECPUC, NERC, NY ISO, PGE, SRP, Tri-State, TVA, UtiliCorp and WPSC. Cleveland also argues that a similar grace period should be given for the implementation of function # 5. (TTC and ATC Calculation). Cleveland at 14.

[515] Florida Power Corp., Florida Commission and Duke.

RTO region. However, these users will have the ability to move power anywhere within the RTO at a single rate and under a single set of terms and conditions. We believe this is pro-competitive and represents one of the fundamental benefits that is envisioned by the Rule. As we noted in the NOPR, the creation of large RTOs that can internalize most, if not all, of the effect of parallel path problems through their scheduling and pricing actions provides a unique opportunity to resolve a major operating concern that has caused problems on both the Eastern and Western Interconnections and which is a significant impediment to promoting efficient competition in generation markets.[516] Therefore, in reviewing the competitive implications of a proposed RTO application under section 203, we believe that any inability of transmission customers to choose among different contract path suppliers within an RTO will be outweighed by their enhanced ability to reach numerous buyers and sellers of electricity throughout the region.

4. Ancillary Services (Function 4)

The fourth proposed minimum function is that the RTO must serve as the supplier of last resort for all ancillary services required by Order No. 888.[517] This supply obligation for the RTO is necessary because only the single grid operator will be able to provide certain ancillary services, not all transmission customers may be able to self-supply (some own generation, others do not), and because it typically is more efficient for the RTO to provide some ancillary services for all transmission users on an aggregated basis.

In carrying out this function, the Commission proposed that all market participants would have the option of self-supplying or acquiring ancillary services from third parties. In addition, the RTO must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided; must be able to exercise direct or indirect operational control over all ancillary service providers; must promote the development of competitive markets for ancillary services whenever feasible; and must ensure that its transmission customers have access to a real-time balancing market.

Comments. Supplier of Last Resort. Comments on whether an RTO should serve as a supplier of last resort are mixed. A large number of commenters support the Commission's proposal, as written.[518] Detroit Edison believes that the RTO should serve as the sole supplier of ancillary services to transmission customers and that the RTO should be permitted either to purchase services directly from generation suppliers or to purchase generation resources for this purpose. First Energy believes that the RTO's obligation as the supplier of last resort for ancillary services cannot be eliminated, since it is the basis of reliability.[519]

On the other hand, a few commenters suggest that the Commission allow flexibility. Duke believes that an RTO should always have the responsibility for ensuring that transmission customers have arranged adequate ancillary service and that those services are delivered. They suggest that where a competitive market for ancillary services exists, the RTO should not be required to provide such ancillary services as a supplier of last resort.[520] And a number of commenters take issue with one or more aspects of the proposed requirements, although many of these commenters generally support the proposal.

For example, some commenters suggest that more information is needed. Southern Company suggests that the Commission allow NERC to finalize an ancillary services policy before mandating changes to ancillary service requirements.[521] Professor Hogan suggests further investigation into developments in ancillary services.[522]

Other commenters believe that the focus of the proposal should be narrowed. Los Angeles suggests that an RTO should be the ''safety net'' of last resort for providing generation-based ancillary services. As such, the RTO would not play a significant role in the energy market and can remain essentially indifferent to energy market issues. PG&E believes that an RTO could set appropriate rules for ancillary services but would not itself procure such services from the marketplace absent clearly defined emergency situations or in its role as provider of last resort. Avista states that while a transitional ''supplier of last resort'' role may be appropriate, an RTO should generally not become deeply involved in any of the markets for generation services.

A number of commenters suggest that the obligation to provide ancillary services should be expanded to include more or different sellers. MidAmerican believes that each control area should retain responsibility for the provision of ancillary services and should be allowed to self-provide or acquire necessary ancillary services in the most economical means it sees fit to meet performance compliance standards. East Texas Cooperatives suggests that the Commission require both transmission owners and the RTO to offer ancillary services at cost-based rates unless a seller can demonstrate a competitive market in a particular ancillary service. PPC and Desert STAR also believe that the role of provider of last resort of ancillary services would better rest with local control areas or independent generators that can supply ancillary services. Steel Dynamics requests that the final rule require generation-owning members of RTOs to maintain Commission approved cost-based tariff schedules for ancillary services. Georgia Transmission believes that any RTO members that are capable of providing ancillary services should be the providers of ''first resort,'' and the ability to acquire such services from different providers would enhance competition in these markets.

While not specifically objecting to the RTO being the supplier of last resort for ancillary services, some parties suggest that the Commission should allow other mechanisms to work.[523] California Board urges the Commission to allow consideration of other means for ensuring that the need for ancillary services is addressed. It recommends that the final rule reflect a requirement that the RTO filings must indicate how default provision of ancillary services will be accomplished without necessarily requiring the RTO to be the provider of last resort. Enron/APX/Coral Power advocates a form of performance-based ratemaking in which the RTO would have an incentive to perform its ancillary service function as efficiently and economically as possible. Florida Commission recommends that an RTO only be responsible for providing non-competitive ancillary services and

[516] *See* FERC Stats. and Regs. ¶ 32,541 at 33,744.

[517] FERC Stats. and Regs. ¶ 32,541 at 33,744.

[518] *See, e.g.,* Entergy, Industrial Consumers, NECPUC, Cal ISO, EPSA, FirstEnergy, LG&E, PacifiCorp, Empire District, EME, Southern Company, UtiliCorp, PGE, PNGC, PSNM, TDU Systems, Nevada Commission.

[519] *See also* Florida Power Corp.

[520] *See, e.g.,* NASUCA, Seattle, CalPX, Mass Companies.

[521] Southern Company notes that NERC's Interconnected Operations Services Working Group is currently addressing the ancillary services that should be required in a competitive environment and has issued a proposed policy for public comment and review.

[522] NWCC recommends that additional research regarding the application of ancillary services to wind and other intermittent generation technologies be conducted.

[523] *See, e.g.,* CMUA, LPPC, California Board, San Francisco, Oneok, SMUD, Avista, Sithe, Seattle.

should require users to purchase or self-provide the other competitive services.

Similarly, FTC suggests that the Commission consider arrangements in which the RTO's primary role is to provide a market mechanism for transmission customers to acquire ancillary services for themselves. It argues that this method may reduce costs by allowing customers to customize their purchases of ancillary services to better fit their specific needs.[524] Some commenters suggest that final RTO regulations expressly recognize the administration of an ancillary service exchange as an alternative to the provider-of-last-resort obligation that is imposed on a RTO under the proposed regulations.[525] For example, ISO–NE believes that a competitive market for ancillary services is a superior supply mechanism, and ISO–NE suggests that the text of proposed § 35.34(j)(4) be amended to read:

> An RTO must develop and maintain a market or other contractual arrangements for the supply of all ancillary services required by Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders.

Comments were also sought on the circumstances under which an RTO's obligation as supplier of last resort could be eliminated.[526] Several commenters believe that the supplier of last resort obligation can be eliminated once a viable competitive market develops within the RTO region.[527] For example, WPSC suggests that an RTO must continue to fulfill the role of supplier of last resort for these services or a power exchange must be available to supply these services. WPSC believes that it would be difficult to predict the circumstances under which the market for ancillary services is sufficiently robust that the RTO's role as supplier of last resort may be eliminated. WPSC believes that it would be a mistake to eliminate that role in any market where the generation market concentration levels as measured by the Herfindahl-Hirschman Index exceed 1,800. TDU Systems states that it is not aware of a market in any of the ancillary services that is now sufficiently competitive to warrant elimination of an ancillary service from this obligation. However, TDU Systems acknowledges that there may never be a competitive market for certain ancillary services and that an alternative mechanism must be created.

[524] *See also* Empire District.

[525] *See, e.g.,* Cinergy, APX, EAL, NY ISO, JEA.

[526] FERC Stats. and Regs. ¶ 32,541 at 33,745.

[527] *See, e.g.,* WPSC, APS, Florida Commission, Duke.

The NOPR also asked for comments on whether a different set of ancillary services requirement for RTOs is needed because RTOs will not own generating resources. Comments on this issue were mixed.

Sithe and several other commenters[528] generally believe the Commission's initial set of guidelines on ancillary services is reasonable, and that a new set of ancillary services requirements for RTOs is unnecessary. LG&E adds that, as already is the case under the open access tariff, an RTO should be allowed to choose to add to the list of ancillary services in recognition of local or regional conditions. MidAmerican believes that while no additional or revised ancillary services are required, an RTO must ensure that sufficient transmission capacity is available to allow delivery of backup supply, planning reserves and the existing six ancillary services.

On the other hand, Los Angeles believes that a different set of ancillary services requirements than those required currently from a vertically integrated utility should apply to an RTO which does not own generation resources. They envision an ultimate industry structure of complete desegregation of generation and transmission assets so that any incentive (either real or perceived) for the transmission provider to act in a discriminatory manner is eliminated.

NSP requests that the Commission refer to the draft NERC policy that discusses the role of an operating authority as an unbundled procurement agent for community ancillary services. They describe this document as a good ''guidepost'' for the Commission to follow in the RTO NOPR, and for the establishment of additional ancillary services such as system blackstart and frequency responsive reserve.[529] Desert STAR and Cal ISO agree that additional blackstart ancillary service may be required. TDU Systems believes that RTOs should be required to offer backup service and an additional load following service. It describes backup service as required to meet contingencies during periods following those covered by the OATT's reserve services, and load following service as required to complement the OATT's minute-to-minute regulation service with a service matching hour-to-hour variations in load. Industrial Consumers recommends that the Commission remove Schedule 4 (energy imbalance service) from any tariff administered by an RTO. They suggest that this service be provided by the real-time balancing market as proposed in the NOPR.

[52] *See, e.g.,* PGE, TDU Systems, Cal ISO, Duke, Tri-State.

[529] *See also* Eric Hirst.

Self-Supply Option. Nearly all who commented on the self supply option generally agree that, where feasible, all market participants should have the option of self-supplying or acquiring ancillary services from third parties. [530] Some commenters strongly endorse the self-supply model. For example, APS believes that it should be the aim of the RTO to have each transmission customer self-supply its generation-related ancillary service requirements to the fullest extend practical. Los Angeles suggests that the role of the RTO should be limited to ensuring that the transmission customer has adequately provided for the necessary ancillary services for each transaction, and the RTO provide such services only in the event of non-compliance. It believes that the RTO should develop specific rules and protocols that would support the self-provision of ancillary services. Some commenters, including PJM/NEPOOL Customers and LG&E, suggest that it is important for the development of a competitive market in ancillary services that RTO customers not be required to purchase them from the RTO, and that an RTO must not prohibit or interfere with the ability of all market participants to have the option of acquiring competitive ancillary services or providing such services through buy/sell transactions from customer-owned generation.

On the other hand, FirstEnergy states that the Commission should be very cautious that policies that encourage self-supply of ancillary services do not compromise the very ability of the RTO to ensure reliable and secure network operation. It maintains that the provision of ''self-supplying'' ancillary services is untested, the infrastructure needed is as yet undeveloped, and the process of providing them could potentially lead to abuses. FirstEnergy identifies this issue as one of the reasons that NERC is pushing for mandatory compliance requirements.[531] It believes that an RTO must have the ability to evaluate and accept/approve those NERC-certified sources that reliably contribute to support the grid.

Authority to Determine Amounts and Location of Ancillary Services. Most commenters generally support the proposal that the RTO have the

[530] *See, e.g.,* CMUA, Cal ISO, LG&E, PG&E, PJM/NEPOOL Customers, PPC, APX, Metropolitan, MidAmerican, NSP, Seattle, SMUD, Desert STAR, TDU Systems, Tri-State.

[531] FirstEnergy notes that NERC is developing certification and verification criteria for ancillary service providers.

authority to determine the quantities and, where appropriate, the location at which ancillary services must be provided.[532] In addition, CMUA suggests that the RTO be responsible for enforcing compliance with established standards.

PJM/NEPOOL Customers requests that RTO decisions regarding the amounts and locations of ancillary services consider both stakeholder input and NERC standards. It believes that this requirement would ensure that the RTO does not impose unnecessarily high ancillary service obligations that will inhibit the operation of the competitive market. In addition, PJM/NEPOOL Customers asks that the Commission ensure that the RTO exercises this authority only to the extent necessary for reliability purposes, since decisions regarding ancillary services could impact the competitive electricity supply market.

NYPP requests that the RTO's authority not be exclusive. It suggests that properly constituted local and regional reliability councils authorized by FERC should have the authority to establish criteria necessary to maintain the reliability of the transmission system including the reliability of discrete locations.

Duke notes that the Commission has previously recognized NERC's leadership role in developing concepts in the area of ancillary services.[533] It encourages the Commission to recognize and adopt NERC's development of ancillary service definitions and reliability standards.[534]

Industrial Consumers and Steel Dynamics request that the Commission first approve the standards by which the RTO determines the requirements. They requests that these standards include the development of ''metrics,'' *i.e.,* standardized units of measurement such that the performance of each service can be verified. In addition, Industrial Consumers recommends modifying the requirement to ensure seamless application between multiple RTOs and for transactions that only go through an RTO. It suggests adding an additional requirement to § 35.34(j)(4)(ii):

The Regional Transmission Organization must support the minimum required amounts of each ancillary service for transactions between itself and other Regional Transmission Organizations in the interconnection and through itself.

Control Over Ancillary Services Providers. All commenters that commented on this subject believe that the RTO should be able to exercise some operational control, either directly or indirectly, over any supplier of ancillary services.[535] SMUD supports the RTO establishing well documented and specific operating criteria and the ability to require compliance with such operating criteria, including monetary penalties and commission-approved sanctions. JEA believes that this control should be exerted only where pre-existing contractual rights are established.[536]

Some commenters would broaden the requirement. For example, FirstEnergy is concerned that limiting the RTO's control to ancillary services providers rather than all generation located within the RTO may compromise the RTO's ability to operate the transmission system reliably. It suggests that the Commission allow a greater flexibility for the RTO and all generation owners located within the RTO to develop an agreement for provision of ancillary services through the RTO that provides for the necessary requirements for voluntary generation participation in the ancillary services market including operational control if appropriate, and the necessary requirements for calling on ancillary services from connected generation necessary for the reliable operation of the transmission system.

On the other hand, PJM/NEPOOL Customers suggest that the RTO control be limited to those providers that the RTO will rely on to fulfill its obligation as supplier of last resort for ancillary services. It claims that control over additional generators is unnecessary and may affect the operation of the competitive market.

Metropolitan recommends that the Commission allow RTO indirect control of existing large hydroelectric plants to protect and facilitate use of existing systems that have been operational for a substantial period of time and to preserve the integrity of the FERC hydro license. It states that allowing indirect control would eliminate the need for costly installation of software and infrastructure.[537]

Promote Competitive Markets for Ancillary Services.Most commenters support the proposal in the NOPR that RTOs promote competitive markets for ancillary services.[538] Seattle suggests that the RTO provide incentives to ensure a robust, transparent market with many buyers and sellers of ancillary services. PJM/NEPOOL Customers states that it is important that the RTO not impede the development of competitive markets for ancillary services and that the RTO actually facilitate the development of these markets. However, it stresses that the RTO and incumbent transmission owners should not be permitted to have market-based rates for ancillary services until a viable competitive market for such services develops.[539]

Sithe advocates that the final rule grant RTOs the authority to administer spot markets for ancillary services and establish rules obligating all participants to meet uniform requirements. PG&E believes that the RTO should not be the sole purchaser of ancillary services. Instead, it should facilitate the development of bilateral markets for as many of the ancillary services as possible, thereby allowing market participants to self-provide those ancillary services.

Access to Real-Time Balancing Markets. In the NOPR, the Commission proposed that an RTO must ensure that its transmission customers have access to a real-time balancing market. We proposed that the RTO must either develop and operate such markets itself or ensure that this task is performed by another entity that is not affiliated with any market participant. The Commission noted that although system-wide balancing is a critical element of reliable short-term grid operation, this does not necessarily require that there be a moment-to-moment balance between the individual loads and resources of bilateral traders and load-serving entities and the schedules and actual production of individual generators. We also noted that unequal access to balancing options for individual customers can lead to unequal access in the quality of transmission service available to different customers, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. The Commission proposed to give RTOs considerable discretion in how a real-time balancing market would be operated.

We invited comments on the use of market mechanisms to support overall system balancing and imbalances of individual transmission users. In addition, we invited responses to the following questions. Is it feasible to rely on markets to support a function that is so time-sensitive? Can such markets be

[532] *See, e.g.,* Industrial Consumers, PJM, Turlock, Cal ISO, Florida Power Corp., PJM/NEPOOL Customers, LPPC, PGE, SMUD, TDU Systems, NYPP, Tri-State, Nevada Commission.

[533] *Citing* FERC Stats. & Regs. ¶ 31,036 at 31,705 (1996).

[534] *See also* Eric Hirst.

[535] *See, e.g.,* PJM, Cal ISO, Florida Power Corp., Cinergy, Los Angeles, PSNM, SMUD, Duke.

[536] *See also* Cinergy.

[537] *See also* NYPP, PSNM.

[538] *See, e.g.,* FTC, LPPC, Avista, APX, PJM/NEPOOL Customers, Seattle.

[539] *See also* TDU Systems.

made to function efficiently if the RTO is not a control area operator? For the imbalances of individual transmission customers, should a distinction be made between loads and generators? Should customers have the option of paying for all imbalances in such a market or only imbalances within a specified band?

Several commenters hold the view that it is indeed feasible to rely on markets to support a balancing function that is time-sensitive,[540] and many agree that access to a real-time balancing market would be of considerable benefit to market participants.[541] NERA claims that technical logic dictates that an electricity system have a central process to co-ordinate real-time physical operations. NERA argues that to the extent that this process is not based on markets, it must be based on less efficient command-and-control methods. NERA also claims that economic and commercial logic requires that a commodity market have short-term trading arrangements to bring market positions into agreement with physical reality, and argues that to the extent that market trading does not reflect physical reality, some non-market process must close the gap between the market and reality. NERA asserts that these two propositions imply that the best way to maximize the role of the market and minimize the role of non-market processes is to base real-time physical operations on a spot market and to allow market participants to use this market for commercial purposes to the extent they find this useful.

Enron/APX/Coral Power states that access to a real-time energy balancing market is central to assuring comparability in open access, and Industrial Consumers believes that this proposal is the beginning of a much needed ''paradigm shift'' in the manner in which ancillary services are defined and provided in the marketplace. Eric Hirst states that implementation of a real-time balancing market would permit FERC to eliminate the Order No. 888 requirement that transmission providers offer an energy imbalance service to transmission customers. He argues that elimination of energy imbalance service, with its awkward and arbitrary deadband and penalty payments, would be a pro-competitive change. Professor Hogan claims that without an efficient spot market and the associated transparent spot prices, it will be much more expensive and difficult to arrange balancing and settlement for the increasing number of retail access programs in the states. East Texas Cooperatives agrees that real-time balancing markets are desirable but believe that simply commanding RTOs to promote the development of competitive markets for ancillary services provides no incentive for the RTO and its members to do so.

Also, two commenters argue that access to real-time balancing markets would eliminate some significant barriers to entry for non-traditional resources such as renewable and distributed energy.[542] In particular, EPA notes that providing such access would eliminate arbitrary energy imbalance penalties that are a major barrier to intermittent resources such as wind and solar energy.

Some commenters believe that the RTO itself should develop and operate a real-time balancing market.[543] PJM/NEPOOL Customers believe that the development of such a market is an essential function of the RTO that will facilitate the further development of retail competitive supply markets. PJM states that a real-time balancing market can best be provided through a power exchange operated by an RTO. Commenters are divided as to whether the development of a real-time balancing market requires that the RTO be a control area operator. Several believe that such markets are possible whether or not the RTO operates a control area.[544] Indeed, MidAmerican believes that, to function efficiently, these markets normally must operate in a region that is larger than a typical control area. However, others take an opposite view.[545] FirstEnergy, for example, argues that the timing, dispatch and telecommunications infrastructure needed to operate a real-time balancing market today can only be done by a control area operator and then only for a combined load within a control area with ample generation resources under automatic generation control.

Some commenters provide detailed recommendations regarding the rules that should govern the RTO's operation of real-time balancing markets.[546] Professor Hogan notes that the complex network interactions in an electric grid require that there be an entity that can provide certain critical coordinating services, and that the most obvious example of such services is energy balancing. He states that the operator should offer an energy balancing redispatch service where market participants can make offers to buy and sell energy.

He believes that the best approach would be to run the balancing market as a ''bid-based, security-constrained economic dispatch'' with voluntary participation by generators and loads. Professor Hogan emphasizes that the RTO must not reject voluntary bids, stating that the natural extension of open access and the principles of choice would suggest that participation in the coordinated balancing market offered by the operator should be voluntary. He states that market participants can evaluate their own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere. He believes that any other rule would require some form of discrimination, and adds that there should be a strong burden of proof for those who argue that it is necessary to restrict voluntary bids, or discard consideration of some bids. Professor Hogan claims that experience in PJM and elsewhere shows that his suggested approach can work.

However, several commenters take a very different view, claiming that the development of a real-time balancing market is not a viable option.[547] For example, FirstEnergy is concerned that a real-time balancing market is not practical to implement. It claims that transmission customers do not yet have the real-time metering and associated communication needed to dispatch and match fluctuating loads to generation. FirstEnergy argues that it would be much better to tie this service to the NERC effort of certifying ancillary service providers for control of generation, and activate the service when the technology and installation can be accommodated. Seattle states that it performs its own real-time energy balancing and expects to continue to do so. Seattle opposes adding this function to an RTO because Seattle believes it will increase the overhead costs of the organization. Seattle believes that market participants that require this service should contract with third parties that stand ready to provide it. Florida Power Corp. states that, given the complexity of implementing short term transmission service in general, it is difficult to imagine that a market for

[540] *See, e.g.,* Duke, PJM, Illinois Commission, Cal ISO, NERA.

[541] *See, e.g.,* Enron/APX/Coral Power, Eric Hirst, NYPP, Powerex, East Texas Cooperatives, Industrial Consumers, Professor Hogan.

[542] *See* EPA and Project Groups.

[543] *See, e.g.,* PJM, PJM/NEPOOL Customers, Professor Hogan, NERA.

[544] *See, e.g.,* Tri-State, Illinois Commission, MidAmerican, Duke.

[545] *See, e.g.,* PJM/NEPOOL Customers, Southern Company, FirstEnergy.

[546] *See, e.g.,* Professor Hogan, Allegheny.

[547] *See, e.g.,* Seattle, FirstEnergy, Florida Power Corp.

energy imbalance service could be developed. It argues that if the market is limited to the generators needed for control, the development of market mechanisms will depend on resolving issues such as the mitigation of potential market power. Florida Power Corp. suggests that an RTO could contract with generators to perform this balancing function using a mechanism that is market-like in that generators would be selected based on their bids to perform the function over some designated period of time, albeit not on an hourly basis.

Several commenters believe that control areas or RTOs should not be the sole provider of energy imbalance services,[548] while others argue that the role of RTOs should be limited to that of a supplier of last resort. [549] UtiliCorp states that, in addition to serving as a supplier of last resort, the RTO must ensure public access to real-time balancing information. SMUD argues that any burden on the RTO that falls outside of the core function of ensuring regional transmission reliability will add cost and complexity to an already costly and complex endeavor. SMUD recommends that the Commission should limit its focus on generation to the role that generation-related service plays in promoting reliable transmission. Desert STAR and FirstEnergy believe that the Commission should give deference to RTOs regarding the development of markets for real-time balancing.

FirstEnergy believes that, ultimately, ancillary service provision must be based on a free-market pricing mechanism, and Southern Company believes that if a real-time balancing market is desired in a region, it will develop without a mandate. FirstEnergy asserts that the detrimental effects of regulated and capped ancillary service markets have been observed in the California and PJM markets. Also, APX believes that the Commission should let the market, not the RTO, provide the trading arrangements in the power industry. APX asserts that efficiency in the competitive market comes from the de-centralized trading activity of self-interested buyers and sellers, and that competition will develop further when market participants self-provide their ancillary services which they acquire in forward contract markets. In APX's view, the RTO should not provide a centrally optimized dispatch because a central dispatch will discourage, if not eliminate, the commitment of forward contracts in the energy market and replace the price discovery of forward markets with *ex post* pricing. To the extent that the RTO must acquire ancillary services, including balancing services, APX believes that the RTO should acquire them from a market created by market participants, and not create its own markets. NERA, however, states that this argument ignores the fact that preventing the ISO from operating balancing markets does not eliminate the network interactions and real-time events that are inherent in any electricity network. Rather, according to NERA, it merely forces the ISO to manage these interactions and events by less efficient and more intrusive non-market means. NERA contends that if the objective really is to maximize the role of competitive market forces and minimize the extent to which the monopoly ISO determines the outcome, the ISO should operate market-clearing mechanisms that reflect network interactions and real-time events as accurately as possible. Similarly, ISO–NE claims that it does not understand how operating a market in which (as in New England, currently) an RTO does not buy and sell the pertinent commodities can constitute ''taking a position'' in those markets such that its operation is perceived as biased. ISO–NE believes that because it does not own market assets or commodities, an ISO-type RTO is exceptionally well situated to run a fair and non-discriminatory market. ISO–NE states that the linkages among transmission operation/dispatch, generation commitment/dispatch, and economic and market forces strongly support the integration of a physical market with an RTO's operations. Nevertheless, ISO–NE states that other financial power markets are welcome and can co-exist in the same region with an RTO market.

Several commenters offered their views as to whether unequal access to balancing options leads to unequal access in the quality of transmission service available to different customers, and whether this is a significant problem when RTOs serve some customers that operate control areas and other customers that do not.[550] A number of commenters believe that the present system does lead to undue discrimination.[551] Enron/APX/Coral Power states that both the NERC and *pro forma* tariff rules are inequitable and discriminatory in that large customers rarely will be significantly out of balance due to the law of large numbers. Enron/APX/Coral Power states that such customers are given great flexibility to balance their scheduled deliveries and load, while smaller customers are much more likely to exceed the 1.5 percent deviation band, making them immediately subject to penalties. Enron/APX/Coral Power believes that by offering real-time balancing to all transmission customers, the NOPR promises to redress this inequity. TDU Systems recommends that, pending the development of competitive balancing markets, the existing inequity between control area operators and other users be partially redressed by enlarging the deadband for imbalances to be repaid or received in kind to no less than five percent of scheduled amounts. It also recommends that the penal character of these charges should be reduced to a ten percent premium, except in cases of abuse.

PJM/NEPOOL Customers argue that, to the extent current control area operators wish to maintain access to inadvertent energy accounts to pay back imbalances and avoid penalties, other transmission customers must have the same opportunity. In the alternative, it recommends that all users be required to cash-out through the RTO balancing process. Utility Engineers recommends implementing a pricing plan for inadvertent interchange by participants of the RTO, where the price for inadvertent interchange is geographically differentiated to reflect losses and constrained transmission paths. They claim that such a pricing plan would need a continuous auction, which could be achieved through establishing a pricing formula.

With regard to providing access to inadvertent energy accounts, other commenters argue that there are valid reasons for distinguishing between customers that are control areas and those that are not. FirstEnergy argues that no other entity, other than control areas, can or should have that access to inadvertent accounts. It claims that, if market participants are provided with the authority to ''go inadvertent'' as control area operators currently have, the strain on the grid would drastically degrade system reliability, requiring much higher reserve capacity requirements. FirstEnergy believes that marketers would ''borrow'' from the grid during high price time periods and make whole on their borrowing during low price time periods, thus distorting the true price signal. Florida Power Corp. notes that in addition to balancing generation against load, control area balancing also includes a requirement for contributing to the maintenance of

[548] *See, e.g.,* Southern Company, Tri-State.

[549] *See, e.g.,* UtiliCorp, Avista, APX.

[550] *See, e.g.,* Enron/APX/Coral Power, LG&E, PJM/NEPOOL Customers, FirstEnergy, TDU Systems, Florida Power Corp.

[551] *See, e.g.,* Enron/APX/Coral Power, PJM/NEPOOL Customers, TDU Systems.

system frequency. In contrast, it notes that the non-control area transmission customer's balancing requirement is limited to the directly measured load it serves. Florida Power Corp. also claims that, if a system of payments was substituted for the inadvertent payback system presently used, control area operators would simply be circulating large sums of dollars between themselves to accomplish the same result at a higher administrative cost. LG&E suggests that the Commission treat such technical issues separate from the RTO NOPR and work in conjunction with NERC's parallel efforts in this area. Also, Florida Commission believes that inadvertent energy accounting between control areas should continue to be allowed within the operating standards of NERC.

With regard to any requirement that loads and resources must be in balance from moment-to-moment, Professor Hogan and Eric Hirst believe there is no need for individual loads and generation to balance their schedules separately, and PJM/NEPOOL Customers states that balancing should be required only to ensure that generators deliver the amount scheduled and committed. Professor Hogan argues that individual balancing requirements both complicate the task for the RTO and provide a device to reinforce market power. Eric Hirst states that the RTO's costs of providing or absorbing imbalance energy should be charged equitably to those that under-generate and over-consume, with compensation to those that over-generate and under-consume. He states that this will result in charges and payments netting roughly to zero in each hour. However, Enron/APX/Coral Power believes that any RTO proposal should include development of an *ex post* energy balancing market in which buyers and sellers are given a finite amount of time after the market has closed to find others with offsetting positions.

Regarding the imbalances of individual transmission customers, commenters disagree as to whether a distinction should be made between loads and generators. MidAmerican and Florida Power Corp. believe that loads and generators should be treated differently. MidAmerican contends that it is much easier to control generators than it is to control load, and in the future managing imbalances will become more complex in that control from the load-side will involve the response of potentially thousands of entities that may or may not respond as quickly as central generation. MidAmerican states that a distinction exists between loads and generators both in magnitude and response time. Florida Power Corp. claims that load and generators are not always similarly situated. It states that the nature of energy imbalance service depends on whether a generator and the load that it serves are in the same control area or are in different control areas. Eric Hirst, TDU Systems, and Duke believe that, in general, the market rules and principles should be the same or comparable for generators and loads, although TDU Systems believes that loads may be less likely than generators to abuse the system by leaning on it. Eric Hirst states that the use of imbalance markets would eliminate the asymmetry between generation and load in FERC's definition of energy imbalance.

Finally, the NOPR also asked whether customers should be able to pay for all imbalances in a market or only imbalances within a specified band. Duke believes that it is appropriate to let the market participants determine how imbalances will be determined and paid. PJM/NEPOOL Customers believes that the RTO should provide transmission users with as many service offerings as possible, including the ability to opt for different balancing pricing proposals. Florida Power Corp., however, believes that there should only be one method of settling the imbalance market. It claims that complexity and opportunities for gaming increase with options for settlement.

MidAmerican believes that transmission customers should pay for all energy imbalances caused by the mismatch of scheduled energy and actual load. It recommends that imbalance charges be based on market prices at the time the imbalance occurred, and should include a penalty, in appropriate circumstances, to deter future imbalances. MidAmerican contends that if transmission customers are allowed to avoid payment within a specified bandwidth, gaming of the transmission system will occur.

PJM/NEPOOL Customers and Professor Hogan, however, argue that the RTO should not be allowed to impose balancing penalties on transmission users. Eric Hirst states that RTOs should maximize the use of price signals rather than penalties to encourage appropriate behavior on the part of generators and loads, and Professor Hogan states that such prices should reflect the marginal cost for power. Eric Hirst believes that penalties should be imposed only to counter the perverse incentives that are created when metering or billing procedures require prices to be calculated over time intervals that do not correspond to those used to measure generation and consumption quantities. Using the example of the California ISO, he states that mismatches between ten minute prices and hourly quantities provide unintended incentives to generators to ignore ISO dispatch instructions or to ignore their schedules. He claims that aligning the time periods for price determination and billing would eliminate these perverse incentives. He adds that, where penalties are needed, they should be closely tied to the costs incurred by the ISO.

TDU Systems argues that if markets for balancing services are fully competitive, transmission users should be able to use them to deal with any amount of imbalance. TDU Systems recommends that until such markets are fully competitive, it may be necessary to restrict such purchases to a deadband to prevent abuse. It believes that any such deadband should be less restrictive than that of the *pro forma* tariff. In that regard, it recommends that the minimum within-band allowance should be no less than the greater of two megawatts or five percent for loads or capacities up to 200 MW, with declining percentage tolerances as loads and capacities increase in size.

Commission Conclusion. We conclude that an RTO must serve as the provider of last resort of all ancillary services required by Order No. 888 and subsequent orders.

Since some commenters interpreted the ''supplier'' of last resort obligation as proposed in the NOPR to require that the RTO be the direct supplier of ancillary services,[552] we have made a minor change to the requirement by substituting the term ''provider'' for ''supplier.'' We clarify that this obligation requires that the RTO have adequate arrangements in place for the provision of ancillary services.

The ancillary services adopted in Order No. 888 were defined using the control area and its operator as the basis because a majority of transmission service was provided by control area operators and they controlled the generation facilities that supplied ancillary services. We note that since we are not requiring the RTO to be a single control area operator, we can not require an RTO that owns no generation to be the direct *supplier* of ancillary services. Therefore we will give the RTO and its participants flexibility in developing adequate arrangements for the provision of ancillary services to all transmission

[552] *See, e.g.,* LPPC, Los Angeles, Georgia Transmission, JEA, PPC. A direct supplier of ancillary services either owns or operates generation.

customers that request service over the facilities under RTO control.

The RTO could fulfill its ancillary services obligations through a variety of mechanisms, including contractual arrangements, indirect or direct control of specified generation facilities, or market mechanisms. However, regardless of the method of provision, the ancillary services must be included in the RTO administered tariff so that transmission customers will have access to one-stop shopping for transmission service.

We conclude that all market participants must continue to have the option of self-supplying or acquiring ancillary services from third parties subject to any general restrictions imposed by the Commission's ancillary services regulations in Order No. 888 and subsequent orders. In such instances, the RTO must determine if the transmission customer has adequately obtained these services. The Commission believes that allowing self-supply provides a possible competitive check on the RTO to ensure that to the extent it does provide the services, it acquires them at lowest cost.

In the NOPR we asked whether additional or revised ancillary services are needed. While a completely unbundled and competitive environment may require a modification to the ancillary services required by Order No. 888, comments suggest that an immediate change is unnecessary. We will not, at this time, make changes to the ancillary services described in Order No. 888. However, we will allow an RTO to propose other services in recognition of local or regional conditions.

We conclude that the RTO must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All generators or other facilities that provide ancillary services must be subject to direct or indirect operational control by the RTO. The RTO must promote the development of competitive markets for ancillary services whenever feasible. To ensure the reliable operation of the system, an RTO must have authority to determine quantities and locations for ancillary services. The RTO should consider stakeholder input as well as established industry standards in determining these requirements. The Commission anticipates that some of the generation-based ancillary services could be acquired in short-term markets. This has been the approach taken by most of the ISOs that we have approved, and we see no reason that this would be different for transcos or other types of RTO entities. Apart from establishing the general requirement to use competitive markets, the Commission will allow the RTO considerable flexibility in determining many of the detailed market design questions, with case-by-case review by us.

As we proposed in the NOPR, we conclude that an RTO must ensure that its transmission customers have access to a real-time balancing market that is developed and operated by either the RTO itself or another entity that is not affiliated with any market participant. We have determined that real-time balancing markets are necessary to ensure non-discriminatory access to the grid and to support emerging competitive energy markets. Furthermore, we believe that such markets will become extremely important as states move to broad-based retail access, and as generation markets move toward non-traditional resources, such as wind and solar energy, that may operate only intermittently.

Some commenters believe that implementation of real-time balancing markets presents technical problems that may prevent RTOs in some areas of the country from making such markets available to market participants. For example, some argue that it is difficult if not impossible for an RTO that is not a control area operator to operate an efficient real-time balancing market. These commenters suggest that to the extent such markets are feasible and desirable in a particular region, the RTO, its stakeholders and market participants should be given the flexibility to develop markets in accordance with their needs and capabilities.

We are not convinced that, at this time, technical considerations preclude the development of a real-time balancing market for any potential RTO. As discussed elsewhere in this Final Rule, we are requiring each RTO to be the security coordinator for its region and to have, at a minimum, the authority to exercise a combination of direct and functional control over facilities within its region. Thus, even if an RTO is not a control area operator, it should have sufficient operational authority to ensure that a real-time balancing market can be implemented. With regard to the issue of flexibility, we believe that real-time balancing markets are essential for development of competitive power markets. Therefore, although we will give RTOs considerable discretion in how they operate real-time balancing markets, we will not allow implementation of such markets to be discretionary.

Our conclusions regarding provision of real-time balancing markets are similar to our conclusions regarding markets for congestion management; that is, we will not prevent an entity other than an RTO that is unaffiliated with market participants, from seeking to offer transmission customers a real-time balancing market. However, because this function is so time-sensitive and requires such close coordination with the actual dispatch, experience may ultimately show that it cannot be performed to a high degree of efficiency unless it is made a part of the RTO's central or hierarchical dispatch activities. Also, we do not agree that an RTO's operation of a real-time balancing market will interfere unduly with the efforts of others to establish markets in forward contracts for energy.

We asked in the NOPR whether customers should have the option of paying for all imbalances in a real-time balancing market or only imbalances within a specified band. Based on the comments received, we decline to give a generic solution for all RTOs in this rule. An RTO may propose one approach or the other but should explain how it proposes to overcome any disadvantages of the approach selected.

In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.

Finally, we asked in the NOPR whether, for the imbalances of individual transmission customers, a distinction should be made between loads and generators. We conclude that, for the purpose of determining cost responsibility for imbalances, no distinction needs to be made. The system-wide balance between load and generation is affected comparably by changes in load and changes in generation. Therefore, the cost of an imbalance is unaffected whether the imbalance is determined ultimately to be the responsibility of load or of generation. However, commenters point out certain differences between loads and generators (such as in the time needed to respond to an operator's instructions) that are important from the standpoint of system operation. These differences can be relevant to the determination of the appropriate penalties to assess to loads and generators that fail to submit accurate schedules. Thus, for purposes of assessing penalties for inaccurate schedules, we conclude that a penalty mechanism that treats loads and generators differently may be appropriate.

5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)

In the NOPR, the Commission proposed that an RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC. The Commission stated that the most controversial aspect of OASIS operation is the calculation and posting of ATC [553] and noted that there is widespread dissatisfaction with the reliability of posted ATC numbers. To alleviate this problem, the Commission proposed that the RTO become the administrator of a single OASIS site for all transmission facilities over which it is the transmission provider.[554] The NOPR outlined three levels at which an RTO could be involved in ATC calculations. At Level 1, the RTO would post ATC values received from transmission owners. At Level 2, the RTO would receive raw data from transmission owners and itself calculate ATC values. At Level 3, the RTO would itself calculate ATC values based on data developed partially or totally by the RTO.

In the NOPR, the Commission envisioned that RTOs would operate at Level 3 to ensure that ATC values are based on accurate information and to minimize the opportunities for manipulation.[555] The Commission also proposed that: (1) An RTO must formulate a validation system to check any ATC data supplied by others; (2) in the event of a dispute over ATC values, the RTO's data should be used pending the outcome of the dispute resolution process; and (3) the RTO must formulate the operating standards (subject to regional and national reliability requirements) underlying ATC calculations.[556]

Comments. Most commenters who address the subject agree with the Commission's observations regarding dissatisfaction with ATC/TTC data. Moreover, most commenters on the subject endorse the proposal that an RTO must be the single OASIS site administrator for all transmission facilities under its control.[557] Some commenters, however, are opposed to mandating the RTO as the OASIS site administrator. For example, Central Maine argues that it should not be precluded from operating its own site because as a ''wires-only company'' it has an incentive to operate an efficient site in order to maximize use of transmission capacity. EEI asserts that OASIS operation can occur independently of formation of an RTO and that the tasks and problems of OASIS operation will not become naturally easier to solve with the creation of an RTO.

Most commenters also support the Commission's proposal to have the RTO independently calculate ATC and TTC.[558] In addition, a number of commenters emphasize that independent and disinterested RTOs could be trusted and empowered to maintain reliable ATC data and calculate accurate values.[559] Moreover, several commenters are concerned with consistency across RTOs and contend that RTOs must also coordinate ATC values with adjacent regions and with the NERC regional reliability councils.[560]

Many commenters concur with the Commission's conclusions about the different levels of RTO involvement in ATC calculations. These commenters believe that Level 1 is insufficient for reliable and trustworthy data and that an RTO should independently calculate ATC values. Several commenters, however, disagree about the appropriate timing for Level 3 compliance. Some commenters, such as Cinergy, argue that upon commencement of operation, an RTO should be required to perform all studies and analysis needed for accurate ATC values consistent with Level 3. APX supports each RTO reaching Level 3 as quickly as possible. Enron/APX/Coral Power asserts that upon commencement of operation, an RTO should operate at Level 2 and, as it gains operational experience, migrate to Level 3. SMUD supports RTO operation at Level 3 but is concerned about the significant costs associated with developing data.

JEA is opposed to any RTO structure that gives an RTO complete authority over ATC calculations for transmission that JEA will continue to own. JEA asserts that transmission owners are in the best position to assess the capabilities of their own transmission system. Therefore, absent formation of a transco, JEA does not support relying on an RTO for ATC and TTC calculations because JEA argues that ownership and control of the assets would be split between two or more entities whose interests are not always the same.

Both Cal ISO and NY ISO argue that the final rule should provide flexibility in the OASIS requirements to accommodate network systems like the Cal ISO and the NY ISO in which transmission service is not explicitly reserved. In addition, numerous commenters argue that the Commission should expand the minimum requirements to have every RTO employ a single set of OASIS practices and terminology.[561] They note that consistency in OASIS procedures will allow seamless trades across RTOs.

How Group also focuses its comments on the standardization of transmission transactions. It notes that without some level of standardization only a limited number of market participants who learn all of the differences between RTOs can perform transactions that span multiple RTOs. How Group proposes that each RTO establish a coordinating committee with neighboring RTOs and transmission customers in order to: (1) Coordinate the naming of interconnected facilities, sources, sinks, paths, points of receipt and/or delivery between the RTO and its neighbors; (2) coordinate the sharing of necessary data for the calculation of transmission capability on interconnected paths; and (3) foster coordination with neighbors in adopting standardized business practices. It also suggests that continued industry-wide coordination is necessary to formulate common definitions for types of transmission and ancillary services, curtailment priorities, and timing

[553] FERC Stats. and Regs. ¶ 32,541 at 33,747.

[554] *Id.* at 33,748.

[555] *See id.*

[556] *Id.*

[557] *See, e.g.,* NASUCA, WPSC, EAL, NERC, Industrial Consumers, Entergy, Mass Companies, JEA, LG&E, NY ISO, NJBUS, Sithe, TAPS, How Group, Southern Company, PG&E, PJM, UtiliCorp, Williams, Cinergy, Oneok, East Texas Cooperatives, Cal DWR, Tri-State, Seattle, New Smyrna Beach, RUS, Cinergy, Nevada Commission, and Enron/APX/Coral Power.

[558] *See, e.g.,* Sithe, RUS, TAPS, PG&E, SMUD, Cal DWR, New Smyrna Beach, East Texas Cooperatives, WPSC, EAL, NERC, NASUCA, Seattle, Georgia Transmission, First Rochdale, Tri-State, Industrial Consumers, Enron/APX/Coral Power, Cinergy, Oneok, PJM, Williams, Empire District, PJM/NEPOOL Industrial Customers, Entergy, Mass Companies, Nevada Commission, NJBUS, and LG&E.

[559] *E.g.,* FMPA, East Texas Cooperatives, NJBUS, Empire District, Entergy, Oneok, First Rochdale, Seattle, EAL, Sithe, WPSC, Sithe, PG&E, SMUD, New Smyrna Beach, and PJM/NEPOOL Customers.

[560] *See, e.g.,* Industrial Consumers, Seattle and WPSC.

[561] *See, e.g.,* Williams, EPSA, Cinergy, Empire District and PJM/NEPOOL Customers.

requirements for arrangement of transmission services.

Only one commenter expressed concern about the proposal to use the RTO's ATC values in the event of a dispute. Southern Company contends that the existing transmission owner's data are preferable to the RTO's data. Southern Company argues that existing transmission owners have experience in operating the regional transmission facilities and, therefore, are best qualified to determine ATC values.

Some commenters raise other OASIS-related issues that were not addressed in the NOPR. For example, commenters argue that: (1) All reservations and scheduling, including that for network service, should occur on the OASIS; (2) sanctions should be levied against transmission providers that skew their ATC values; and (3) the power flow methodology rather than the contract path model should be used for scheduling.[562] A few commenters address issues relating to Capacity Benefit Margin (CBM). NASUCA argues that administration of CBM should be a required function of RTOs and that a uniform methodology for calculating CBM is needed. Similarly, Idaho Commission asserts that requiring the posting of CBM on OASIS with a narrative explanation of its derivation would be beneficial. Empire District states that the Commission should provide better guidance about how to calculate CBM.

Commission Conclusion. After considering the comments, we continue to believe that an RTO must be the single OASIS site administrator for all transmission facilities under its control. As numerous commenters note, independent RTOs can be trusted to maintain an OASIS site with reliable and current data that is easy to use. In addition, a single OASIS site for each region instead of multiple sites will enable transactions to be carried out more efficiently.

However, in response to those who argue for flexibility in OASIS requirements, we clarify that this requirement does not mean that each RTO must itself operate the OASIS for its region. Our concern is that there be no more than one OASIS site for the facilities under the RTO's control, and that the RTO ensure that the OASIS site operator have the same attributes of independence we require for an RTO. Thus, we will allow an RTO the flexibility to contract out OASIS responsibilities to another independent entity, if justified. More specifically, we do not intend to keep an RTO from participating in a ''super-OASIS'' jointly with other RTOs.

We reaffirm that an RTO should operate at what the NOPR characterizes as Level 3 for ATC/TTC calculations, which requires the RTO itself to calculate ATC values based on data developed partially or totally by the RTO. Most commenters believe that Levels 1 and 2, where the RTO would accept the transmission owners' ATC calculations or data, are insufficient for reliable and trustworthy ATC values. Level 3 ensures that ATC values are based on accurate information and consistent assumptions. When data are supplied by others, the RTO must create a system for tests and checks that ensure customers of coordinated and unbiased data. We also agree with commenters who recommend that RTOs coordinate ATC values with adjacent regions.

We recognize that the NOPR was silent on the appropriate timing for Level 3 compliance. Commenters suggested that: (1) An RTO should reach Level 3 compliance upon commencement of operation; (2) an RTO should reach Level 3 as quickly as possible; or (3) an RTO should operate at either Level 1 or 2 upon commencement of operation and as it gains operational experience, migrate to Level 3. We conclude that an RTO OASIS site, including ATC calculations, must be fully operational at Level 3 upon commencement of service. All parties to a transmission transaction need precise ATC values to make scheduling decisions.

We affirm that in the event of a dispute over ATC values, the RTO's values should be used pending the outcome of a dispute resolution process. Only one commenter, Southern Company, disagreed with this proposal and we are not persuaded by its arguments. Each RTO must develop procedures to validate its ATC values.

How Group and other commenters address issues relating to the standardization of transmission transactions. Standardization of transactions involves two separate concerns: (1) Many transactions will cross RTO boundaries; and (2) numerous customers will do business with multiple RTOs. Without standardized communications protocols and business practices, the costs of doing business will be increased as market participants will be required to install additional software and add personnel to transact with different RTOs and regions. Therefore, to promote interregional trade, standardized methods of moving power into, out of, and across RTO territories will be needed.

We believe that standards for communications between customers and RTOs must be developed to permit customers to acquire expeditiously common services among RTOs. For example, we envision the creation of standardized communications protocols to schedule power movements and to acquire auction rights. These protocols would not standardize what the rights are, or the nature of the auctions. Instead, the focus of the communications protocols would be on how customers communicate their intentions to an RTO and how customers receive an RTO's responses.

We agree with How Group and others that certain business and communication standards[563] are necessary, and we believe that these standards will facilitate the development of efficient markets. We believe, however, that these issues need further examination based on a complete record.

A few other commenters discussed issues that were not addressed in the NOPR. For example, commenters argue that: (1) All transmission transactions (reservations and scheduling) should occur on the OASIS; (2) sanctions should be levied against transmission providers that skew their ATC values; and (3) the power flow methodology for scheduling, rather than the contract path model, should be utilized. In addition, NASUCA, Empire District and the Idaho Commission raise issues relating to CBM. These issues are too detailed for this proceeding and we will not address them at this time. Commenters will have the opportunity to bring up these issues in response to specific RTO filings, as well as during OASIS Phase II proceedings and in the CBM docket (Docket No. EL99–46–000).

6. Market Monitoring (Function 6)

In the NOPR, the Commission proposed that RTOs perform a market monitoring function. Specifically, RTOs would be required to: (1) Monitor markets for transmission service and the behavior of transmission owners and propose appropriate action; (2) monitor ancillary services and bulk power markets that the RTO operates; (3) periodically assess how behavior in markets operated by others affects RTO operations and how RTO operations

[562] *See, e.g.,* Ontario Power, Williams, NERC and EPSA.

[563] We believe that the communications standards and protocols would, like the current OASIS, make use of: (1) The Internet for communications; (2) interactive displays using World Wide Web browsers; (3) file uploads and downloads for computer-to-computer communication; and (4) templates defining the file uploads and downloads.

affect those markets; and (4) provide reports on market power abuses and market design flaws to the Commission and affected regulatory authorities, including specific recommendations. In addition, the Commission asked a number of questions regarding the role of RTOs in market monitoring, the tools RTOs should use, and similar issues.

Comments. Commenters address a number of issues regarding the market monitoring function. The issues can be grouped into three general areas: (1) The need for and scope of a market monitoring function; (2) who should perform the market monitoring function and how it should be performed; and (3) what are the specific components or procedures of a market monitoring plan.

Need For and Scope of Market Monitoring. As a general proposition, a variety of commenters favor having RTOs serve as market monitors.[564] Commenters, such as Blue Ridge, argue that RTOs should conduct market monitoring because they will be in the best position to deal with the growing volume of multiparty transactions and discern any manipulation or preferential treatment. Several commenters, such as the Florida Commission, note that the appropriate role for RTOs in market monitoring and the various aspects of the function will depend upon the nature of the RTO that is ultimately established. TEP claims that RTO market monitoring needs to be flexible given the costs involved in such a function. PP&L Companies believes that RTO market monitoring should focus on properly structuring business rules to foster efficient transactions and gathering statistical information to make available to the Commission or other enforcement agencies. EEI and Allegheny recommend that RTO market monitoring identify market design flaws and propose solutions that lead to greater efficiency, competitiveness and reliability.

A number of commenters support having the RTO should serve as the ''first line of defense'' for detecting design flaws and market power abuses.[565] Cal ISO suggests that the RTO serve as a first line of defense in conjunction with state commissions and local regulatory authorities in the region, particularly in the operation of hourly and real-time markets where potential buyers may not have the ability to decline electric service, and where transmission and ancillary services markets tend to have high concentrations. PJM believes that market monitoring by RTOs provides a continual check on market activities and accordingly, RTOs should have clear authority to investigate potential market power abuses or flaws and to compel market participants to produce relevant information. SMUD contends that although RTO monitoring should be the first line of defense, an independent RTO monitoring unit must not be a substitute for review by the Commission and other regulatory agencies.

In contrast, some commenters, such as Cinergy, argue that, if transmission markets realize the efficiencies envisioned in the NOPR, the commodity market should be able to regulate itself, with the Commission and the courts serving as backstops. SNWA cautions that RTOs may be too focused on safe and reliable operations to be a first line of defense. Some commenters, such as Metropolitan and Southern Company, claim that there is no benefit in having RTO monitoring replicate the costly regulatory responsibility that already exists in state and Federal agencies.

Several commenters propose an expansive RTO market monitoring role. NECPUC proposes that monitoring include mitigation of both market flaws and market power. East Texas Cooperatives and SMUD believe that RTO market monitoring should include remedying market abuse. Project Groups believes that an RTO should monitor energy and ancillary services markets and their interplay, and develop indices and criteria to evaluate activities and behaviors that may reflect market power abuse. Advisory Committee ISO–NE suggests that the RTO monitor transmission and ancillary services markets to identify design flaws and market power, and to administer or propose remedial actions. Dynergy claims that monitoring should include oversight of transmission owners' behavior. EPSA proposes that the RTO also document any significant market impacts attributable to application of reliability rules.

Some commenters support limits on market monitoring by the RTO. Commenters, such as Southern Company and Entergy, argue that RTO monitoring should not reach to any market the RTO does not operate, nor should it encompass market power abuse and the effect of existing structural conditions on the competitiveness of electricity markets. Entergy adds that the RTO will not be in a good position to monitor markets it does not operate. Several commenters claim that the purpose of monitoring should be to look for market flaws, not act as policeman looking for bad behavior.[566] Desert STAR recommends that any proposed remedy be restricted to market flaws within the RTO's area of operation. Enron/APX/Coral Power argues that evaluation of the structure of power markets and policing market power lies outside of an RTO's core competencies as the operator of the transmission system. Tri-State opposes RTO monitoring of power markets because it would add to the complexity and cost of RTOs and impermissibly involve the RTO in issues about generation market power. NY ISO opposes monitoring to the extent that it encompasses the RTO playing an investigative and enforcement role. Nonetheless, in its view, the RTO could mitigate evident market power problems on a prospective basis by applying pre-approved remedies.

Sithe recommends that RTOs not have the authority to compel the provision of commercially sensitive data and should instead rely on nonproprietary information to monitor markets. PG&E contends that commercially sensitive information should not be released to anyone except in accordance with Commission-approved rules. PP&L raises concerns regarding the ability of the RTO market monitoring organization to guarantee confidentiality of commercially sensitive information supplied to it. Seattle argues that any claims of commercial sensitivity must be tempered by the need to create an efficient, self-policing, transparent market for nondiscriminatory transmission services.

Various commenters would limit the RTO market monitoring function to information gathering.[567] They argue that the NOPR proposal is overly broad, too extensive and open-ended, and a potentially burdensome requirement. Sithe argues that the application of mitigation measures by the RTO could have real commercial impacts on market participants that often cannot easily be measured or repaid after the fact; therefore, market participants should have an opportunity to review and comment on monitoring procedures prior to their implementation. Seattle claims that the Commission should take a minimalist approach by facilitating market monitoring through greater public information disclosure. PG&E believes that the RTO should not regulate the functioning of the energy market. Duke supports RTO identification and description of alleged market abuses to appropriate authorities

[564] *See, e.g.,* New York Commission, South Carolina Authority, Mass Companies, LG&E, ISO–NE, TAPS, SMUD, NECPUC, WPSC, Project Groups and Tri-State.

[565] *See, e.g.,* Metropolitan, DOE, CMUA, NASUCA and Project Groups.

[566] *See, e.g.,* Desert STAR, CRC and Tri-State.

[567] *See, e.g.,* CP&L, TDU Systems, PP&L and PG&E.

through the regulatory framework that exists today.

Other commenters question the need for or otherwise oppose an RTO market monitoring function, in general, as a form of back door regulation.[568] They contend that RTO monitoring will be unduly burdensome, overtaxing and costly to the ratepayers. Los Angeles and Salomon Smith Barney argue that RTO monitoring may interfere with the proper relationship between the RTO and its customers, which they claim should be focused solely on providing nondiscriminatory open access transmission services. UtiliCorp argues that the assignment of market monitoring functions to a commercial entity such as a transco (other than those functions concerned strictly with transmission pricing) may raise antitrust concerns both for the transco and its customers.

Commenters differ on whether market monitoring should continue indefinitely. East Texas Cooperatives believes that continuous RTO market monitoring is necessary because, in its view, antitrust laws and complaints to the Commission provide only a slow, after-the-fact remedy. Entergy recommends that any RTO self-monitoring be allowed to terminate after a fixed period, subject to Commission approval. Industrial Consumers suggests that market monitoring be limited to the period when the risk of discriminatory conduct is greatest. Los Angeles claims that, once the Commission determines that generation markets are workably competitive, market forces should be allowed to discipline the markets. If an RTO market monitoring function is required, PSE&G suggests a five-year sunset provision.

Who Should Perform Market Monitoring and How Should it Be Performed. Many commenters address the issue of whether the RTO should perform market monitoring depending on the form of the RTO (*i.e.*, whether the RTO is a for-profit or a not-for-profit organization). Most commenters raise concerns about and generally oppose a for-profit RTO monitoring markets.[569] The commenters generally argue that, due to its economic and business interests, a for-profit RTO cannot objectively monitor itself. CP&L submits that a for-profit RTO may be a competitor of other market participants in the provision of congestion relief and ancillary services, which would make unbiased monitoring of those markets difficult. TDU Systems would limit a for-profit RTO's role to data collection. Other commenters recommend that for-profit RTOs employ a fully independent organization to monitor market conditions.[570] A few commenters, however, support for-profit RTOs serving as market monitors.[571] Entergy claims that market monitoring conducted by a transco could be as effective as for any other type of RTO as long as procedures are in place that ensure its independence.

Commenters also address whether an RTO that is an ISO needs to insulate its market monitoring function from other RTO functions to ensure independence and objectivity. A number of commenters generally believe it is appropriate for ISOs to internally monitor market activities either through staff devoted to the function or through a committee of ISO members assigned to the function.[572] They argue that an ISO, which would be free of commercial interests, can be trusted by market participants, and therefore should not have to undertake costly establishment of autonomous monitoring units. Mid-Atlantic Commissions note that PJM ISO's monitoring unit is a neutral body that has access to and maintains confidentiality of market sensitive data in accordance with sharing arrangements with each of the states in the region. California Board contends that, if the internal unit is independent and has the ability to report and/or consult with state and Federal authorities without needing additional approval, those regulators are likely to respect the opinions and recommendations of the market monitoring unit. CalPX suggests that RTOs and separate power exchanges coordinate their market monitoring functions and jointly conduct research to lower costs. EPSA suggests that the information and market data, if collected by an independent and unbiased RTO, could be relied upon by market participants in formulating business strategies, and by regulators for purposes of reviewing and approving modifications to regulated aspects of RTO structures and operations.

Most commenters, however, would require an ISO (*i.e.,* a not-for-profit RTO) to make its market monitoring function more independent. Pennsylvania Commission contends that an independent ISO is absolutely necessary to perform market monitoring functions. EEI points out that while an RTO's independence may ensure that its recommendations do not favor particular market participants, this does not ensure that it will monitor its own performance objectively. In its view, an ISO should use outside experts within the monitoring committee or on an ad hoc basis to address concerns about objectivity. Similarly, PG&E contends that experience has shown that an ISO's rules and actions may interfere with the proper functioning of the market. Industrial Consumers contend that an RTO's operations must be sufficiently transparent that it is the market participants that do the real monitoring. FTC suggests that internal RTO monitoring could be problematic if the internal monitoring unit is given enforcement powers, because this could both devolve into re-regulation and raise conflict of interest issues. FTC recommends that the Commission's RTO rules explicitly make clear that self-monitoring controlled by an RTO does not create an antitrust exemption for the RTO and its participants.

Los Angeles believes that market monitoring should be conducted by an independent body. CP&L, however, believes that delegation to a private party is questionable, where its objectivity may also be challenged on grounds of conflict of interest, particularly, if the delegated authority includes the ability to impose sanctions and penalties. Oregon Commission believes that RTOs should appoint a local committee to use RTO data to monitor the market for ancillary services because RTOs, as major buyers and sellers of such services, will want to protect their market shares. The Commission should consider establishing its own regulatory advisory bodies to monitor markets. DOE also claims that the Commission should avoid reliance upon RTO monitoring to the exclusion of the Commission's own monitoring efforts. Alliant believes that moving responsibility for monitoring market power to another organization would allow the RTO to focus on the many technical demands that will be placed on it. Metropolitan believes market monitoring should occur on two levels: an internal group responsible for data gathering and publication and frequent preliminary analysis of anomalous conduct; and formal analyses performed by a group or committee independent of RTO management whose results and recommendations would not require RTO approval.

LG&E proposes that the RTO make its monitoring findings public and refer

[568] *See, e.g.,* Industrial Consumers, Williams, Southern Company, PSE&G, Arizona Commission, Georgia Transmission and East Kentucky.

[569] *See, e.g.,* Dynegy, South Carolina Authority, Industrial Consumers and East Texas Cooperatives.

[570] *See, e.g.,* PJM/NEPOOL Customers, Cal ISO, Tri-State and Metropolitan.

[571] *See, e.g.,* Entergy and Duke.

[572] *See, e.g.,* PJM, ISO–NE, NY ISO, WPSC and East

them to an appropriate regulatory body. Industrial Consumers opposes giving deference to the RTO's recommendations for correcting such market power abuses and flaws. Instead, it believes that stakeholders and market participants should use the RTO reports to make their own recommendations.

NYPP believes that structural solutions are matters for legislators, courts or regulatory agencies. In contrast, PJM believes that, if the market issue is a structural one, the RTO should be able to propose structural remedies to the Commission.

In the case of localized market power, MidAmerican submits that it would be inappropriate for the RTO to take corrective competitive actions in the case of localized must run generating unit market power. Similarly, PG&E contends that RTOs should allow temporary supply and price issues to be resolved by the competitive forces of the market, unless there is a threat to the physical supply of power or a Commission determination that markets are not workably competitive.

CalPX believes that monitoring and reporting should be simplified in order to reduce costs and to rationalize staff and committee work loads. Also, the RTO and power exchange compliance related staffs should jointly conduct research that is beneficial both to increase coordination and reduce costs. NY ISO submits that RTOs that are ISOs should not be required to establish costly and otherwise burdensome autonomous market monitoring units.

Many commenters address the issue of the appropriate role for the Commission and the state commissions in market monitoring. Commenters overwhelmingly believe that the Commission and state commissions have an important role to play, whether it is a primary role as market monitors, or a secondary role providing oversight of market monitoring activities by RTOs.

Some commenters believe that market monitoring is better handled by the existing statutory and regulatory agency frameworks than by RTOs.[573] They suggest a continuing, if not mandatory, role for the Commission and other Federal and state authorities in conjunction with any market monitoring undertaken by RTOs.[574] PP&L Companies argues that, in *Gulf States Utilities Co.* v. *FPC,*[575] the Supreme Court made it clear that the Commission is charged with serving as the first line of defense to protect and preserve competition in wholesale power markets.

TDU Systems and Sithe contend that regulatory commissions cannot abdicate to RTOs the responsibility to ensure that wholesale electric markets are free of market power. Many commenters see RTOs serving to forward any claims of market abuse and market power to the various federal and local regulatory agencies consistent with their respective jurisdictions. PJM and LG&E see the Commission reviewing remedies and approving penalties and sanctions. Desert STAR and CRC see the Commission acting as a backstop to an RTO's ADR process or mitigation plan. EEI suggests that RTOs regularly inform the Commission about monitoring results, which will enable it to respond quickly to problems not resolved by the RTO. SoCal Cities suggest that RTOs share responsibility to remedy structural defects in the market or impose general sanctions for market power abuse with appropriate state and federal agencies, but not duplicate their responsibilities such as implementation of the FPA. CalPX believes that there is a decreasing role for regulatory oversight as a result of a progression toward greater RTO self-regulation.

Florida Power Corp. and Nevada Commission suggest close coordination of RTO market monitoring with state regulators. Nevada Commission also suggests that RTOs collaborate their monitoring efforts with neighboring RTOs, as well as audit the records of those parties who violate the RTO's rules. Project Groups recommends adding an eighth minimum function under which RTOs provide data support for states' policies, monitoring the competitive impacts of emissions regulations, verifying compliance with state generation portfolio standards.

NARUC claims that the states need to be heavily involved in RTO market monitoring and that the Commission should work with the states to make utility codes of conduct more effective. In its view, such collaboration is the most effective means of monitoring market power in generation, since the RTO would have information for the region on transmission planning, generation expansion and transmission constraints, and state commissions would have utility specific data and information on local operations. NARUC argues that such collaboration is critical because state commissions are responsible for both evaluating local markets to assure competitiveness and for licensing electric supplies, and abusers of market power can inhibit competition and distort the prices of locally regulated services. NASUCA similarly claims that market participants, state and federal regulatory agencies, and state consumer advocates periodically review the indices and screens to be used for RTO market monitoring. The RTO should periodically issue confidential reports to federal and state regulatory authorities and state consumer advocate offices, that describe the state of the markets and the results of matters under investigation.

A number of state commissions suggest a continuing oversight role over RTO monitoring by the Commission and the states.[576] Oregon Commission recommends that the Commission establish its own regulatory advisory bodies to monitor ancillary services markets. For a for-profit RTO, it recommends that a regional oversight committee perform this function with the Commission reviewing any oversight committee reports.

Commenters also address a number of issues related to the ability of RTOs to perform self-assessments. A number of commenters believe that RTOs are capable of objective analysis. NY ISO contends that an ISO will have no incentive to distort the results of its analysis. Cinergy recommends that RTOs be limited to monitoring the behavior of the markets they administer because of the ready access to relevant information. Los Angeles comments that, if the RTO is not primarily responsible for providing ancillary services, it should not be burdened with surveying that market.

Other commenters oppose RTOs monitoring the markets that they operate because of conflict of interest concerns.[577] EEI argues that independence from market participants does not ensure that the RTO will be able to monitor its own performance objectively, *e.g.,* a non-profit RTO may not have sufficient incentives to minimize the costs under its control. Oregon Commission comments that RTOs cannot be entrusted to monitor ancillary services markets, where they will be providing services and have incentives to protect market share. Industrial Consumers contends that market participants must perform monitoring and, accordingly, an RTO's operations should be fully transparent. SNWA and PG&E claim that the RTO

[573] *See, e.g.,* Salomon Smith Barney, South Carolina Commission, PG&E, Enron/APX/Coral Power and Duke.

[574] *See, e.g.,* SMUD, Tri-State, Cinergy, TDU Systems, EPSA, Industrial Consumers, CMUA, PJM/NEPOOL Customers, NY ISO, ISO–NE and DOE.

[575] 411 U.S. 747 (1973).

[576] *See, e.g.,* Florida Commission, New York Commission and Michigan Commission.

[577] *See, e.g.,* Florida Power Corp., CMUA and DOE.

should establish an independent body to monitor and evaluate its performance.

Some commenters, such as Salomon Smith Barney and Michigan Commission, oppose the RTO monitoring markets where the RTO takes a market position because the RTO plays the dual role of seller of services and policeman. Alliant contends that an RTO will be competing with generation providers in congestion management and have an incentive to build transmission facilities. Similarly, CP&L contends that a for-profit RTO may compete with others in providing ancillary services, and therefore any proposal by the RTO monitor for remedial action raises serious conflict of interest concerns. Industrial Consumers suggests that, even in markets where the RTO is the supplier of last resort, the RTO should not have quasi-regulatory powers.

Commenters also address the issue of whether RTOs should be required to provide periodic assessments of markets they do not participate in or operate, thereby assessing the effect of existing structural conditions on the competitiveness of their region's electricity markets. Some commenters oppose this proposal. Tri-State opposes an RTO monitoring of power markets because it would not only violate the Commission's goal of separation between transmission and power sales, it would also add a level of complexity and cost to the operation of the RTO. Justice Department believes that the RTO cannot reasonably be expected to monitor activities with which it has no involvement. Justice Department therefore recommends that the Commission consider requiring each separate electric power trading institution to monitor any market that it operates.

On the other hand, a number of commenters favor extending RTO monitoring responsibility to markets they do not operate. PJM/NEPOOL Customers argues that the independence of the RTO would enable market participants and the Commission to have confidence in the RTO's assessments. ISO-NE favors RTOs monitoring power markets. NASUCA recommends that RTOs monitor bulk power markets, capacity markets, transmission rights markets, ancillary services markets and any other potentially competitive markets. FTC suggests that, where an RTO is smaller than one of the major interconnects, the Commission may wish to encourage all the RTOs within each of the interconnects to coordinate their efforts to examine the effects of market rules or variations between RTOs in market rules on the volume and price of inter-RTO transactions. Cal ISO also sees collaborative market monitoring and assessment by neighboring RTOs and at the national level.

Florida Power Corp. recommends that an RTO that is an ISO be required to make regular assessments as to whether it has sufficient operational authority to ensure its ongoing ability to provide reliable, open access transmission service on a comparable basis to all customers—nonetheless, the RTO should not be self-regulating.

For those regions where the real-time balancing function is performed by an ISO, Advisory Committee believes that the ISO should monitor market power in generation markets. SoCal Edison claims that, where markets are not yet workably competitive, the RTO, with Commission approval, should ensure that prices are just and reasonable through appropriate temporary mechanisms such as price caps. PG&E counters that, in no case, should RTOs be permitted to use control of a power exchange for unilaterally capping prices set by the market.

Many commenters address the issue of how the RTO should report, if at all, its monitoring activities. The Commission did not propose to establish detailed standards on the format and content of monitoring reports, noting that such matters are best left to the RTO. We asked commenters to address whether reporting should be limited to when a specific problem is encountered, or whether periodic reporting on the state of competition and transmission access would be more appropriate.

Commenters express mixed views on reporting requirements. CRC supports the concept of RTOs reporting to the Commission regarding RTO design flaws, and New York Commission suggests that RTOs report on market power abuse as well. Florida Power Corp. submits that, if market monitoring is necessary, it should be performed by the RTO reporting and filing appropriate information with state and Federal regulators. Project Groups wants the provision of data to support state programs pertaining to the monitoring of the competitive impacts of emissions regulations. Project Groups argue that RTOs would be uniquely positioned to support data collection for verification of green marketing claims and compliance with information disclosure requirements and portfolio standards. EEI opposes a Commission mandate for RTOs to track generation source and emissions data. EEI recommends the RTO voluntarily undertake this task to meet specific state compliance requirements provided appropriate safeguards protect competitively sensitive information. EEI expresses concern regarding the possibility that the RTO would have authority to collect and disclose information from a generation source where the state has not imposed such a requirement.

Several commenters favor issuance of monitoring reports at regular intervals. Project Groups believes that RTO monitoring units should issue public reports on their activities and findings, including annual reports on the general state of the market. Metropolitan supports reporting at regular intervals from an external monitoring source; however, during initial startup, more frequent reporting is advisable to assist participants' understanding of the market operation. East Texas Cooperatives believes that RTOs should prepare periodic reports to the Commission with the precise form left to the discretion of the RTO.

California Board contends that regular reports on market performance should issue at least on a yearly basis, and include all relevant data that can be made publicly available. NASUCA contends that, to further create trust in the RTOs' ability to effectively and objectively monitor the market, RTOs should periodically issue reports describing the state of the markets that it is monitoring, items under investigation by the RTO, and any results from completed investigations. In its view, market participants, state and federal regulatory agencies and state consumer advocates should participate in the development and periodic review of the indices and screens the RTO will use to monitor the operation of the markets. Reports should be provided to state and federal regulatory authorities as well as state consumer advocate offices, on a confidential basis, to enable them to independently assess whether additional investigation is merited. Cal ISO submits that the Commission should specify regular reporting requirements for the RTO's monitoring unit. PJM believes that RTOs should periodically report results of monitoring activities to the Commission and state agencies.

Components of a Market Monitoring Plan. Commenters address various issues regarding particular elements of a market monitoring plan. Many commenters address the issue of whether RTOs should be allowed to impose penalties and sanctions. Most commenters would limit the RTO's ability to impose penalties or sanctions. Many of them argue that such authority should remain the province of the regulatory and antitrust agencies.[578] Justice Department claims that RTOs lack experience either in detecting exercises of market power or in making recommendations on correcting market power problems. SPRA questions whether the imposition of sanctions by the RTO may conflict with the Supremacy Clause of the Constitution and whether affected public power bodies could only consent to such sanctions if they do not create indefinite or uncertain liabilities. PP&L argues that, because it will be judge and jury, the RTO must demonstrate competitive harm before taking any market action. Some commenters, such as CP&L, note that a for-profit RTO may not be objective in imposing sanctions because it competes with other market participants. Other commenters, such as Salomon Smith Barney, claim that RTOs should be limited to extracting ordinary commercial penalties when market participants fail to follow the market's rules. EPSA claims that RTOs should be empowered to intervene in a market within the strict confines of the Commission's oversight only when a situation has the potential to become catastrophic. Mass Companies opposes allowing a private RTO or one that is operated by a non-stakeholder board to enforce violations of market standards and impose sanctions and penalties.

Canada DNR claims that it will be problematic for Canadian entities subject to the jurisdiction of Canadian provincial and Federal energy regulators also to be subject to an RTO that has its disciplinary authority backstopped by the Commission. In its view, the issue will not be resolved by simply having the appropriate Canadian regulator serve as the regulatory backstop to the RTO for each Canadian entity because the Canadian regulator may take a different position than the Commission.

A few commenters support authority for RTOs to impose penalties and sanctions. Among them, CalPX believes that RTO governing boards and power exchange market monitoring committees must be able to take appropriate action either by referral to regulatory agencies or directly through applicable sanctioning authority. It views this as critical for self-policing and providing prompt remedies before problems detrimentally affect market results. ISO–NE believes that an RTO should have the ability to impose penalties and sanctions, but suggests that the RTO not act as an antitrust agency, in order to increase the acceptability of sanctions among participants.

[578] *See, e.g.,* Entergy, Duke, PG&E, PSE&G, PJM/NEPOOL Customers and Williams.

The Commission specifically sought comment on whether penalties should be limited to violations of RTO rules and procedures, or whether the RTO should be allowed to impose penalties for the exercise of market power. More commenters oppose than support RTOs imposing sanctions and penalties for market power abuse. Among them, Allegheny and Metropolitan claim that this is a proper function of regulatory or antitrust authorities. Central Maine argues that the Commission cannot grant RTOs the authority to impose corrective actions without affording the affected public utilities with procedural due process. EEI believes that the RTO tariff may include RTO authority to impose fines or sanctions to ensure compliance with RTO rules in accordance with the costs imposed by their actions. Pointing to similar positions taken by Justice Department and FTC, EEI contends, however, that the RTO should not attempt to define or prosecute alleged exercise of market power because it is not a regulatory body or an antitrust agency authorized to take such actions. It also suggests that limited additional authority might be granted during the transition to restructured markets to permit the RTO to deal effectively and timely with identified market design flaws, software errors, or other unanticipated situations that could be costly if no action is taken.

Cinergy also argues that the RTO should not be allowed to take corrective action against individual market participants. It believes that claims of market abuse and the exercise of market power should be forwarded to the Commission to address consistent with its jurisdiction. Similarly, MidAmerican recommends that RTO penalties be limited to (1) willful violations of material RTO directives related to the operation of regional transmission facilities, Commission approved RTO standards for transmission facility operations, and material provisions of RTO agreements that conflict with the RTO transmission tariff, and (2) violations of RTO transmission tariff provisions relating to operating reserves and energy imbalances. NASUCA recommends that compliance with RTO rules be enforced with penalties and sanctions imposed through a collaborative process involving all market participants, regulatory agencies and consumer advocates. However, the Final Rule should specify that any actions taken by the RTO cannot substitute for penalties or other remedies which may stem from independent investigations by governmental authorities. Similarly, ISO–NE and SNWA generally would impose sanctions based on a participant's engaging in patterns of conduct defined in the RTO's rules or its tariff.

NYPP, DOE, and LG&E generally concur that RTO sanctions and penalties should only be levied for violations of RTO rules and procedures, whereas penalties and sanctions for market power abuses are matters for the regulatory and antitrust agencies, legislators, or the courts. Florida Power Corp. argues that, since an RTO does not have authority to grant or terminate market-based rate authorizations premised respectively on the absence or presence of market power, the RTO should therefore have no role in passing judgement or imposing penalties for the exercise of market power.

On the other hand, some commenters, such as East Texas Cooperatives, are more comfortable with RTO imposition of penalties and sanctions for market power abuse. PJM recommends that RTOs be able to take corrective action to ameliorate market abuses or flaws and to seek Commission approval to add penalties and sanctions to its market monitoring plan. NECPUC recommends that market monitoring be expanded to include formalized mitigation and sanction rules in connection with market design, implementation flaws and market power. NY ISO claims that RTOs should mitigate evident market power problems, on a prospective basis, by applying pre-approved remedies. CRC submits that RTOs investigate whether market power abuse results from a design flaw and report the results to the Commission for approval of its mitigation plan. WPSC sees RTOs being effective because they will have access to real-time data on system conditions and should be given authority to take appropriate corrective action immediately to respond to market abuses.

Some commenters also want sanctions against market participants for reliability rule violations. PSNM claims that RTOs should defer to existing mechanisms where they exist (such as the WSSC's Reliability Management System RMS, and NERC Reliability Standards and Measures) for sanctions against market participants for poor performance, rather than create new monitoring and sanction systems for RTOs. Similarly, Desert STAR submits that any RTO should be allowed to pass the reliability performance standards sanctions on to participants who do not comply. SMUD concurs that an important aspect of enforcing reliability standards is ensuring that the RTO has sufficient authority to police and investigate the markets they administer, and assess fines and other appropriate penalties, or resolve disputes amongst market participants as to any alleged market abuse.

A few commenters also address the Commission's questions about how much discretion the RTO should have in setting penalties (*e.g.,* should the RTO's penalty authority be limited to collecting liquidated damages). Nevada Commission submits that RTOs should be allowed to impose specific penalties and sanctions for non-compliance with RTO rules based on liquidated damages and not punitive damages. Cal ISO and Metropolitan believe that penalties should be limited to liquidated damages. Cal ISO argues that for cases of repeated or intentional violations or serious abuses of market power, the RTO should seek relief, including imposition of punitive damages, from the Commission or other appropriate agencies such as the Justice Department. Metropolitan argues that liquidated damages sought by an RTO should be approved by the Commission. And Duke opposes the RTO assuming the role of market monitor and enforcer; therefore, it recommends that terms and conditions for any penalties the RTO might impose should be agreed upon by contract during the RTO development process.

On the other hand, WPSC claims that the RTO should have the discretion to determine the amounts of adequate sanctions and penalties to discourage anti-competitive conduct. Whether the RTO has acted properly can always be reviewed after the fact through a dispute resolution procedure either through the Commission or the Justice Department. NASUCA contends that sanctions and other penalties should be large enough to be an effective deterrent. It suggests that a for-profit RTO may have incentives to impose unjustified penalties and should be required to allocate all revenue derived from sanctions and penalties in a way that benefits customers. SMUD offers that, since liquidated damages are a mere proxy designed to make a victim whole for a transgression, they do not really serve as a deterrent to market abusive conduct.

Several commenters address whether the SEC model of regulating stock exchanges, *i.e.,* requiring extensive and sophisticated market monitoring of stock exchanges, should applicable to RTO market monitoring. Some commenters, such as EEI and PP&L, do not believe the model is applicable. EEI claims that monitoring scheme in the securities industry is an exception because in most industries the market participants bring competitive problems to the attention of antitrust authorities. Sithe also opposes any emulation of the NASD or NYMEX model of self-regulation at this time because of the limited amount of market experience to date.

PJM/NEPOOL Customers and Cal ISO, however, contend that the RTO monitoring function should be similar to that of a stock exchange because the RTO is designed to ensure that the exchange of electricity can occur readily and easily in a competitive marketplace.

Commission Conclusion. In the NOPR, the Commission proposed that RTOs perform a market monitoring function. Many commenters raise a number of issues regarding market monitoring. The issues largely encompass the following concerns: the need for and scope of a market monitoring function; who should perform this function and how it should be performed; and what are the specific components or procedures of a market monitoring plan.

The Commission recognizes that the market monitoring concept is new and not yet well-refined, either at the Commission or within existing ISOs. We also acknowledge the apprehensions of some parties that market monitoring by an RTO could intrude into markets and affect their behaviors. The Commission, however, is engaged in finding ways to understand market operations in real-time, so that it can identify and react to any problems that are preventing the most efficient operations. It also has a responsibility to protect against anticompetitive effects in electricity markets.[579] If we are to satisfy this goal, we must systematically assess whether our policies and decisions are consistent with this responsibility. Market monitoring is an important tool for ensuring that markets within the region covered by an RTO do not result in wholesale transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power. In addition, market monitoring will provide information regarding opportunities for efficiency improvements.

However, in light of the different forms of RTOs that could be developed by market participants and the varying types of markets an RTO may be operating within its region, different market monitoring plans are likely to be appropriate for different RTOs. Consequently, after careful consideration of the comments, the Commission will require that RTO proposals contain a market monitoring plan that identifies what the RTO participants believe are the appropriate monitoring activities the RTO, or an independent monitor, if appropriate, will perform. We believe that such approach will provide those proposing an RTO sufficient flexibility to design a monitoring plan that fits the corporate form of the RTO as well as the types of markets the RTO will operate or administer. We have revised the regulatory text for the RTO market monitoring function to reflect our decision to allow this flexible approach.

Although we decline at this time to prescribe a particular market monitoring plan or the specific elements of such a plan, the RTO must propose a monitoring plan that contains certain standards. The monitoring plan must be designed to ensure that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by that information. The monitoring plan also must evaluate the behavior of market participants, including transmission owners, if any, in the region to determine whether their behavior adversely affects the ability of the RTO to provide reliable, efficient and nondiscriminatory transmission service. Because not all market operations in a region may be operated or administered by the RTO (*e.g.,* there may be markets operated by unaffiliated power exchanges), the monitoring plan must periodically assess whether behavior in other markets in the RTO's region affect RTO operations and, conversely, how RTO operations affect the efficiency of markets operated by others. Reports on opportunities for efficiency improvement, market design flaws and market power abuses in the markets the RTO operates and administers also must be filed with the Commission and affected regulatory authorities.

In developing its market monitoring plan, the RTO should identify the markets that will be monitored, *i.e.,* transmission, ancillary services or any other market it may develop (*e.g.,* congestion management). With regard to those markets, the monitoring plan should examine the structure of the market, compliance with market rules, behavior of individual market participants and the market as a whole, and market power and market power abuses. The monitoring plan should also address how information will be used and reported. The monitoring plan

[579] *See Gulf States Utilities* v. *FPC,* 411 U.S. 747, 758–59 (1973).

should indicate whether the RTO will only identify problems and/or abuses or whether it also will propose solutions to such problems. We note that sanctions and penalties may be appropriate for certain actions such as noncompliance with RTO rules. However, the monitoring plan should clearly identify any proposed sanctions or penalties and the specific conduct to which they would be applied, provide the rationale to support any sanctions, penalties or remedies (financial or otherwise) and explain how they would be implemented. With regard to the reporting of market monitoring information, the monitoring plan should indicate the types and frequency of reports that will be made and to whom the reports will be sent. Under the FPA, the Commission has the primary responsibility to ensure that regional wholesale electricity markets served by RTOs operate without market power. An appropriate market monitoring plan must provide an objective basis to observe markets and, if appropriate, provide reports and/or market analyses. Market monitoring also will be a useful tool to provide information that can be used to assess market performance. This information will be beneficial to many parties in government as well as to power market participants. This includes state commissions that protect the interests of retail consumers, especially where they are overseeing the development of a competitive electric retail market. We note, however, that the market monitoring function for the RTO does not limit the ability of each state within the RTO's region or other authorities to decide the nature and extent of its own market monitoring activities.

We are not requiring a plan that necessarily involves the collection of data the RTO would not collect in its ordinary course of business. We believe that the information collected through the RTO market monitoring plan will reflect data that the RTO will collect or have access to in the normal course of business (*e.g.,* bid data, operational information). In light of our requirements that the RTO have operational control over the transmission facilities transferred to it and the RTO be the security coordinator for its region, the RTO will be in the best position to perform (or provide information to another entity, if appropriate, for it to perform) objective monitoring functions for the markets that the RTO operates or administers in the region.

In response to commenters' arguments that RTO market monitoring results in an impermissible shift of Commission authority to other entities, we emphasize that performance of market monitoring by RTOs is not intended to supplant Commission authority. Rather it will provide the Commission with an additional means of detecting market power abuses, market design flaws and opportunities for improvements in market efficiency. Further, because market monitoring plans will be required to be filed with and approved by the Commission as part of an RTO proposal, we will retain the ability to determine what, how and by whom activities will be performed in the first instance.

Because we believe market monitoring is essential, we decline to set any sunset date for monitoring at this time. However, as bulk power markets evolve and become more competitive, we may revisit the need for the type of monitoring the Rule requires.

7. Planning and Expansion (Function 7)

In the NOPR, the Commission proposed that the RTO planning and expansion process must satisfy certain standards. Specifically, RTOs would be required to: (1) Encourage market-motivated operating and investment actions for preventing and relieving congestion; and (2) accommodate efforts by state regulatory commission to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary. We suggested that RTOs be designed to promote efficient use, which requires efficient price signals such as congestion pricing, and efficient expansion of their regional grid, which requires control over planning and expansion. We specifically proposed that the RTO have ultimate responsibility for both transmission planning and expansion within its region. If the RTO is unable to satisfy the planning and expansion requirement when it commences operation, we proposed that the RTO must file a plan with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. In addition, the Commission sought comment on whether three years is an appropriate amount of time for implementation of this function.[580]

Comments. Encourage Market-Motivated Operating and Investment Actions for Preventing and Relieving Congestion. Many commenters support the Commission's proposal to require that an RTO must ensure the development and operation of market mechanisms to plan and refinance transmission system expansion. As part of this an RTO should provide all transmission customers with efficient price signals that show the consequences for their transmission use decisions.[581]

Some commenters, such as JEA and Williams believe that this role is best performed by for-profit entities because system expansion decisions must be driven by economic considerations. Entergy also contends that a transco will not create any bias in the method of grid expansion.

Los Angeles agrees that an RTO should rely upon market signals and market solutions in assessing all feasible options (*e.g.,* construction of new generation, redispatch of existing generation, grid expansion) to assure the least-cost option is pursued. NASUCA also argues that the Commission should mandate that RTOs use least-cost planning on a region-wide basis for transmission system expansions and upgrades. It notes that the larger the region over which least-cost planning is conducted, the more economically efficient the outcome is likely to be. If market solutions do not develop or are not timely, Los Angeles believes that the RTO must have the power to resolve the transmission problem. LG&E proposes that RTOs be permitted to use competitive bidding as a means to meet new transmission investment needs.

EPA believes that RTOs should adopt a resource planning process with sufficient flexibility to consider non-traditional resources and to assign appropriate values to their unique benefits. EPA further believes that RTOs should be encouraged to take into account environmental costs and benefits that are not reflected in resource prices.

Puget suggest that the Commission should recognize that the concept of RTOs may contain some elements that do not enhance the reliable operation of the transmission grid. Puget requests that the Commission should address more fully how it will mitigate the effects of the severance of generation and transmission planning and operation and how it plans to ensure maximum reliability at the lowest integrated costs.

NASUCA recommends that the Commission require RTOs to develop a baseline regional transmission expansion plan that would identify the regional system's ability to meet essential NERC reliability criteria and

[580] FERC Stats. & Regs. ¶ 32,541 at 33,751–53.

[581] *See, e.g.,* United Illuminating, Wyoming Commission, Industrial Consumers, Champion, NSP, PG&E, Williams, LG&E, FTC and APX.

isolate potential constraint areas of the existing system where upgrades may be necessary or additional generation desirable. Such a baseline plan could provide a valuable tool to market participants in signaling the best locations for new generation projects. Entergy proposes the use of a regional transmission plan that includes a regional transmission planning summit process involving all stakeholders.

TAPS, however, questions whether market-based mechanisms to expand the transmission grid will emerge readily from an efficient short-term transmission pricing regime that accounts properly for the costs of congestion. TAPS asserts that, while efficient congestion pricing is an important component of a well-designed transmission regime, it is not the answer to the concerns that have been raised regarding the lack of economic and regulatory incentives to expand the transmission grid.

Many commenters agree that RTOs should be responsible for conducting the studies necessary to assess the need for new transmission system enhancement.[582] However, some commenters argue that the role of the RTO should be to facilitate market investment by others in new transmission and generation, not to lead the market by making its own plans for new facilities. For example, Seattle suggests that the RTO should generate information on the locations, frequencies and costs of congested paths to guide capital investment. It believes that the RTO need not make capital investments directly; rather it should seek market mechanisms, such as requesting bids for needed capacity, to encourage investments. EME states that performance of this role requires accurate accounting for the impact of congestion and new generation, and proper allocation of costs to those that require such costs to be incurred.

To ensure that transmission expansion decisions are not biased, ComEd proposes that RTO functions be performed by two linked organizations that together make up a ''Binary RTO.'' ComEd envisions that the Binary RTO would consist of for-profit independent transmission companies (ITCs), each operating a large aggregation of existing transmission systems, under the oversight of an independent, not-for-profit Regional Transmission Board (RTB). The ITCs will identify transmission additions, upgrade opportunities, and prepare long-range plans which would be reviewed by the RTB and subsequently integrated in an RTB-wide planning system.

Powerex believes that it is better to eliminate congestion at its source through facilities upgrades, if economically and environmentally feasible, than to attempt to manage congestion on a long-term basis through congestion pricing schemes.

Many commenters support the concept that RTOs must be responsible for transmission planning and that single-system planning should be the objective of the RTO planning process.[583] Commenters differ, however, on the extent of the RTO's role in the planning process. Some commenters, such as Powerex, argue that the RTO must have control over transmission service, planning, system impact studies and facilities studies, and the authority to determine the need for, and require the implementation of, transmission upgrades by member utilities. Other commenters, such as LIPA and H.Q. Energy Services, propose that, in the absence of transmission expansion proposals from current or proposed market participants, the RTO should have the responsibility for assessing whether transmission improvements are needed and, if a need is found, the RTO should have the authority to order such expansion.

Some commenters such as NY ISO, on the other hand, express concern that exclusive authority by the RTO over transmission planning is overly restrictive. NY ISO claims that entities which are responsible for coordinating transmission expansion, but which lack authority to make enforceable planning decisions, can nevertheless achieve the Commission's primary transmission expansion-related goal, *i.e.,* ensuring that investments in new transmission facilities are coordinated to ensure a least-cost outcome that maintains or improves existing reliability levels.

H.Q. Energy Services objects to NY ISO's arguments as being merely concerned with preserving its so-called ''two-tier'' governance system which provides NY ISO transmission owners with significant authority, or veto power, over interconnections with generating facilities and over decisions related to transmission system planning and expansion. H.Q. Energy Services does not believe that the two-tier approach is appropriate unless the RTO has ultimate decision-making authority.

Many commenters agree with the proposal that an RTO must be ultimately responsible for all transmission expansions and upgrades.[584] These commenters claim that transmission operations must be conducted on an independent and fair basis and must be undertaken by an impartial entity if transmission services are to be offered on a truly non-discriminatory basis. They argue that vesting the RTO with the ultimate responsibility for expanding transmission systems eliminates the conflict that is inherent in vesting these responsibilities with an entity that also has commercial interests that are competing with users of the system.

Although SMUD supports having the RTO be responsible for transmission planning and expansion, it cautions that, in such a paradigm, people that have no responsibility to the ratepayers will be deciding planning and expansion issues. Therefore, SMUD argues that the Commission needs to scrutinize the recovery of the costs of such expansion to ensure that such expansion decisions and costs are prudent, just and reasonable.

Several commenters agree that the RTOs can and should play a significant role in the transmission planning and expansion process.[585] Some of these commenters, such as NYPP and Mass Companies, however, do not believe that the Commission should require that RTOs have authority to order a transmission owner to modify or expand its transmission system. Nevada Commission believes that transmission owners should be allowed to assist an RTO in the development of grid planning criteria and could take the lead in such grid planning with RTOs performing more of an overview role. Professor Joskow states that the transmission owners, operating through a sound RTO/ISO transmission planning process should be expected to be the primary, but not necessarily the exclusive, source of network enhancement initiatives. WEPCO argues that transmission owners should be integrated into the RTO regional transmission plans where they can be improved and expanded to meet regional needs most efficiently. Turlock contends that the RTO's authority over the transmission system it operates must be limited to that system. Turlock argues that the RTO should not have the ability to force expansion of lower voltage or tangentially related facilities which are beyond the area of its responsibility, even if those other facilities might have a small but

[582] *See, e.g.,* EME and Seattle.

[583] *See, e.g.,* PNGC, Wisconsin Commission, EAL, Entergy, PJM, Minnesota Power and Montana-Dakota.

[584] *See, e.g.,* San Francisco, SoCal Cities and CMUA.

[585] *See, e.g.,* NYPP, Industrial Customers, Mass Companies and Nevada Commission.

theoretically possible impact on the RTO's facilities.

CP&L supports a coordinated planning approach which would be similar to the planning approaches identified in the Midwest ISO and the Alliance RTO filings, where the RTO would have responsibility for review of the transmission plan, but the individual transmission-owning entities would provide the necessary input to facilitate the development of the comprehensive RTO transmission plan. East Kentucky argues, however, that an individual transmission owner should be able either to require or to veto the building of a particular RTO facility.

MidAmerican disagrees with the proposal that the RTO have the ultimate responsibility for both transmission planning and expansion in the region. MidAmerican claims that existing regional transmission groups (RTGs) have clear and prominent roles in transmission expansion decisions in which planning for transmission improvements are coordinated through collaborative processes that already involve many interested stakeholders in the widest fashion possible. MidAmerican states that throughout the MAPP region there is broad support for continuing transmission planning and expansion decisionmaking as a collaborative function and that the existing collaborative processes adequately accommodate RTO participation.

Central Maine believes that RTOs/ISOs can and should play a significant role in the transmission planning and expansion process, but disagrees with the Commission's proposal to give ISOs ultimate responsibility for transmission planning and expansion. Central Maine does not object to ISOs having oversight responsibility in these area, but Central Maine believes that the planning and engineering functions should be a shared responsibility between utilities and RTO, *i.e.*, the Commission should consider utility planners as a satellite to the ISO/RTO similar to satellite function served by utility control centers in monitoring, switching and dispatching. Central Maine states that the Commission should grant individual transmission owning utilities an equal voice in determining the technical aspects of transmission planning and expansion.

Although Big Rivers believes that, as proposed in the NOPR, the RTO should be the default provider of transmission planning and expansion, it agrees with NRECA that incumbent transmission owners should have the first opportunity to build required transmission system expansion with RTO ability to facilitate needed construction by others.

Some commenters suggest specific tasks and functions that the RTO should perform or have the ability to require as part of the transmission planning and expansion function.[586] For example, SRP proposes that at a minimum, each RTO should have the authority to: (1) Direct transmission owners to study and evaluate system performance and to develop plans to solve known reliability or adequacy problems; (2) revise or combine elements of transmission owners' plans to achieve the most efficient and reliable transmission expansion plan; (3) approve or reject any component of the RTO transmission plan developed by a transmission owner; and (4) approve facility additions by third parties.

Accommodate Efforts by State Regulatory Commission to Create Multi-State Agreements to Review and Approve New Transmission Facilities. Many comments concur that multi-state agreements are to be encouraged and that the RTO should be designed to work within that structure.[587] Commenters, including NSP and Nevada Commission, encourage the Commission to provide an active role for RTOs to participate with state and local government in the siting and licensing of new facilities. PJM states that a cooperative relationship between RTOs and the states is essential to effective transmission expansion planning. In PJM's view, states are more likely to trust the planning decisions of RTOs that have no commercial interest in transmission and generation expansion than decisions made by transmission-owning entities, which have commercial interests.

Cinergy recommends that the final rule include a Commission commitment to proceed aggressively to establish a forum to encourage coordination of RTO planning and expansion among states through multi-state certification agreements and multi-state regional planning boards. Cinergy notes, however, that the creation of a forum or agency to review grid planning and expansion that would consider the public interest beyond the constraints of state boundaries may require federal legislation. If so, the Commission should be aggressive in its dialogue with Congress to obtain the requisite legislative relief.

The Kentucky Commission suggests creating a voluntary ''Joint Board on Regional Transmission Siting'' to develop and review standards for transmission expansion. The Joint Board would include participation from the Commission, state commissions, RTOs, and other interested parties. The Joint Board would also convene ad hoc committees to review specific transmission expansion proposals. Pennsylvania Commission also prefers a joint Federal-state approach towards regulating RTO site approvals, expansion, innovation and customer service. It notes that a joint Federal-state approach has been used with success in other areas, such as the Susquehanna River Basin Commission, the Delaware River Basin Commission and the Joint Pipeline Office which regulates the Trans-Alaska Pipeline System.

Illinois Commission recommends that accommodation of multi-state efforts be expanded to include the possibility of multi-state regional regulatory oversight organizations. Such organizations could be instrumental in coordinating regional solutions to regulatory and policy issues.

Otter Tail expresses concern that multi-state agreements may not actually add to the efficient use and expansion of the interstate transmission system due to a danger that these types of agreements could be mired in state-versus-state political conflict and become unworkable, to the detriment of transmission owners, generators, and ultimately customers. Industrial Consumers also does not believe that requiring an accommodation with ''multi-state agreements'' is necessarily productive. It states that nothing now prevents such coordination among states, yet there is no obvious evidence that this will work. Industrial Customers believes that states will always reserve the right to veto a project that may be partially situated within their jurisdiction, regardless of the benefits elsewhere.

East Texas Cooperatives believes that retention of state public utility commission authority over siting (and other necessary approvals) is necessary to control the risk of overbuilding because RTOs will have no real incentive to limit facility construction.

Commenters generally express support for the proposal that the RTO build on existing RTG processes.[588] For example, Industrial Consumers urges that the Commission require existing RTGs to merge their functions with the RTOs because RTGs should not be allowed to develop an institutional

[586] *See, e.g.,* Project Groups, LIPA and SRP.

[587] *See, e.g.,* Illinois Commission, DOE and New Smyrna Beach.

[588] *See, e.g.,* Wisconsin Commission, Industrial Customers and SRP.

culture that diverges from the goals and objectives of RTOs.

New Smyrna Beach and Oneok claim that market participants will undoubtedly benefit from a multi-state siting process for transmission because it may make siting of new generation easier if there is more certainty that related transmission siting decisions will be made on a timely basis with one-stop shopping.

Several commenters address the role of the Commission in the RTO planning and expansion process. Detroit Edison and Wolverine Cooperative support the establishment of the Commission as the primary channel of certification for transmission siting, construction, and expansion. Detroit Edison states that regional reliability organizations and the RTOs in each reliability region should be permitted to determine necessary changes and additions in transmission with input from transmission owners, control area operators, and other interested parties. It is vital, it states, that a single administrative agency resolve issues related to the siting of transmission facilities on a regional basis and have the authority to approve transmission expansion plans on a timely basis. Detroit Edison believes that the Commission should fill the important role of sole regulator over transmission siting and construction, just as it currently does in approving the siting and construction of natural gas pipelines, and it urges the Commission to work to gain such authority.

Pennsylvania Commission recommends that, if an RTO determines that transmission expansion is necessary, it should file with the Commission to demonstrate that need. Once the Commission determines a need exists within the RTO, the RTO should then file with the appropriate states for a determination of the siting issues. Pennsylvania Commission believes that vesting authority for determining the need for transmission expansion with the Commission solves several problems that are certain to arise in state forums. Federal determination of the need for transmission expansion obviates the burden of filing with multiple jurisdictions and possibly receiving conflicting determinations.

Otter Tail states that Commission should seriously consider whether the public interest would be better served through adoption of a transmission siting policy that is similar to review of interstate natural gas pipelines.

NY ISO claims that in many cases transmission expansion is delayed or blocked entirely by environmental and other transmission siting regulations. Nevertheless, NY ISO supports the NOPR's proposal that RTOs participate in efforts to create multi-state transmission expansion agreements.

East Kentucky believes that there needs to be some regulatory oversight authority for facilities that are deemed necessary by an RTO planning staff. East Kentucky proposes that this regulatory authority be the Commission or a regional regulatory authority.

Conlon recommends that the Commission have the necessary authority to enforce reasonable siting request, or critically needed future transmission lines could be delayed causing a reliability risk. Granting the right of eminent domain to transcos or ISOs in Federal legislation would be another approach. This could be accomplished by the Commission recommending to Congress that it have the right of eminent domain.

LG&E believes that it is important that state authority over system expansion not impede necessary improvements that enhance the efficiency of the regional grid that is, or will be, subject to RTO control. Ultimately there may be a need for a congressional solution to the current balkanized system for authorizing grid expansion. In its comments, the East Central Area Reliability Council explicitly calls for such legislative action based on its concern that transmission facility expansion requests will fail as they become bogged down in multiple state reviews. LG&E shares this concern. Still, until such time as the statutory framework for transmission expansion is amended, LG&E believes that RTOs represent an opportunity for coordinating regional transmission expansion needs among transmission owners and state authorities.

Project Groups maintains that RTOs should be required to coordinate and lead in the development of comprehensive least cost regional plans for assuring short-and long-term system reliability, and they must coordinate the actions necessary for implementing timely system upgrades and additions pursuant to those plans. For example, RTOs must be given the authority to petition state and local regulators for necessary siting authorizations, including certificates of need or public necessity and environmental permits, as well as the authority to order construction of facilities sited and permitted under state regulatory authorities. The Commission should encourage state reliance on RTO-approved plans as the primary basis for the exercise of eminent domain powers under state law.

Puget notes that state condemnation powers granted to utilities are usually limited for the benefit of the citizens of the state in which the utility operates. It is not clear that a state utility can delegate its state condemnation power to a regional RTO. Therefore, the final rule should expressly address how state condemnation authority can be legally exercised by a regional RTO.

NASUCA maintains that the RTO regional planning efforts must not displace state government siting authority. NASUCA states that the final rule should specifically recognize state statutory authority to regulate siting of transmission facilities. For other planning and expansion matters, the Commission should require RTOs to establish a process to ensure that the RTO obtains input from state government agencies with respect to the regional transmission plan. Nevada Commission states that it is imperative that the RTO coordinate transmission siting and planning with state agencies. Tri State believes that states should continue to fulfill their traditional roles in siting transmission facilities. However, it notes that it may be necessary for the states to consult with the RTO on transmission facility certification since the RTO will be charged with overall responsibility for transmission planning and will be required to work cooperatively with states and other regional groups.

CP&L supports state and local governments retaining the authority for certification and siting of new transmission facilities. These government agencies are closer to the local residents who will be affected and can best evaluate the great number of factors that must be considered in approving transmission routes.

Several commenters address the issue of eminent domain authority as a component of the transmission planning and expansion function. East Kentucky believes that the issue of eminent domain needs to be addressed for not only RTOs, but also for the entire open access transmission network. East Kentucky questions whether an entity, if required by an RTO or the Commission to construct a transmission facility, has eminent domain authority that is sufficient to allow the entity to acquire all property rights necessary to construct the required facility. Consequently, East Kentucky argues that, as a general proposition, Congress needs to grant federal eminent domain authority to any entity that is required by the Commission or any form of RTO to build a facility so that such entity can acquire private property rights under Federal law. Because it believes that siting of transmission has become the principal impediment to transmission expansion, EPSA also advocates that the RTO should be delegated sufficient authority to direct transmission owners or others to excise their eminent domain authority, as necessary, to implement transmission system expansion plans independent of the source of funds or the beneficiary of the project. Under current law, this authority must come from the states. Thus, EPSA also advocates the passage of Federal legislation that vests the Commission with primary jurisdiction over major transmission planning and siting decisions, perhaps subject to a requirement that the Commission consult with a regional siting authority or a consortium of affected state siting boards.

Central Maine disagrees and recommends that the Commission should reject EPSA's comments. Central Maine notes that, if a state government intends that an RTO have the power of eminent domain, the state legislature will grant it. Central Maine argues that RTOs should not be granted the power to do something indirectly that they may not do directly. Consequently, it believes that EPSA must pursue its proposal through the enactment of state legislation.

Whether Three Years Is an Appropriate Amount of Time for Implementation of This Function. Several commenters support the Commission's proposal to allow up to three years to implement the planning and expansion function.[589] Some commenters, however, believe that three years is too short.[590] South Carolina Authority suggests a five-year period. Florida Commission believes that it is premature to set any time limit for implementation of the planning and expansion function.

On the other hand, several commenters believe that three years is too long a period.[591] Most of these commenters believe that the planning and expansion is such an important function that its implementation should not be delayed at all. NYC suggests that implementation should not be delayed more than a year. SRP argues that the uncertainty that currently exists about who ultimately will be responsible for building and paying for new transmission facilities is causing delays in upgrades. According to SRP, requiring the RTO to perform this function upon commercial operation will eliminate this uncertainty.

Industrial Customers also argues that any delay should not be used as an excuse to stall the construction of any facility for which the need has been established. SRP suggests that, if a delay in implementation is permitted, the RTO should be required to identify the entity responsible for financing and building transmission expansion prior to the RTO assuming such responsibility.

Commission Conclusion. We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities. In carrying out this overall responsibility, the Commission has concluded that the NOPR's three separate requirements for RTO planning and expansion must also be satisfied or, in the alternative, the RTO must demonstrate that an alternative proposal is consistent with or superior to these three requirements. Specifically, an RTO must satisfy the requirement to: (1) Encourage market-motivated operating and investment actions for preventing and relieving congestion; (2) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary; and (3) file a plan with the Commission with specified milestones that will ensure that it meets the overall planning and expansion requirement no later than three years after initial operation, if the RTO is unable to satisfy this requirement when it commences operation.

As noted above, the RTO should have ultimate responsibility for both transmission planning and expansion within its region. The rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability. We also recognize that the RTO's implementation of this general standard requires addressing many specific design questions, including who decides which projects should be built and how the costs and benefits of the project should be allocated.[592] As with other requirements of the Final Rule, we propose to give RTOs considerable flexibility in designing a planning and expansion process that works best for its region. It is both inevitable and desirable that the specific features of this process "should take account of and accommodate existing institutions and physical characteristics of the region."[593] We emphasize that, as the transmission provider in the region, the RTO is required to provide service under a tariff that is consistent with or superior to the Commission's *pro forma* tariff, and that tariff obligates the transmission provider to expand and modify its system to provide the services requested under the *pro forma* tariff.[594] Because an RTO may not own all of the facilities it operates, we clarify that nothing in this Rule relieves any public utility of its existing obligation under the *pro forma* transmission tariff to expand or upgrade its transmission system upon request. Accordingly, we shall evaluate each RTO proposal to ensure that the RTO can direct or arrange for the construction of expansion projects that are needed to ensure reliable transmission services.[595] However, the Commission reiterates, as discussed below, its strong preference for market-motivated operating and investment actions.

We further note that the pricing mechanisms and actions used by the RTO as part of its transmission planning and expansion program should be compatible with the pricing signals for shorter-term solutions to transmission constraints (*i.e.,* congestion management) so that market participants can choose the least-cost response. Otherwise, their choices may reflect less efficient outcomes for the marketplace. For example, if the price of expansion overstates its cost (or the price of congestion management understates actual congestion cost), market participants likely will continue congestion management solutions to a transmission constraint when

[589] *See, e.g.,* Tri State, SoCal Edison and PNM.

[590] *See, e.g.,* NECPUC, Duke and South Carolina Authority.

[591] *See, e.g.,* Champion, NYC, Turlock, SRP, TDU Systems and Industrial Customers.

[592] FERC Stats. and Regs. ¶ 32,541 at 33,751–52.

[593] *Id.* at 33,752.

[594] *See, e.g.,* Section 15.4 of the *pro forma* tariff which requires the transmission provider to use due diligence to expand or modify its transmission system to provide requested services. Also, Section 28.2 of the *pro forma* tariff requires the transmission provider to plan, construct, operate and maintain its transmission system in order to provide network service, and to endeavor to construct and place into service sufficient transmission capacity to deliver network resources to network customers on a basis comparable to its own use of the transmission system.

[595] We note that existing ISOs have addressed similar issues successfully. For example, the PJM ISO is responsible for expansion planning, but the transmission owners remain obligated to undertake upgrades necessitated by the plan, 81 FERC ¶ 61,257 at 62,275 (1997).

expanding the system to relieve congestion is more efficient.

Market-Motivated Actions. Planning new generation or new transmission requires a coordinated approach to ensure reliability and efficient congestion management. However, this does not necessarily imply that all transmission expansions must be centrally planned by the RTO. Where feasible, an RTO should encourage market approaches to relieving congestion. A market approach will require providing all transmission customers with access to well-defined transmission rights and efficient price signals that show the consequences of their transmission usage decision. If the RTO's market approach is successful, the decisions of where, when and how to relieve congestion will be driven by economic considerations.

Most commenters agree with the NOPR proposal that RTOs should rely upon market signals and market solutions in assessing all feasible options (*e.g.,* construction of new generation, redispatch of existing generation, as well as expansion of the transmission grid) to assure that the least costly option is pursued. If an RTO can facilitate market-motivated decisions, several commenters point out that its planning role may largely be limited to extreme circumstances where continuing congestion in an area threatens reliability. However, we also recognize that different market approaches to relieving congestion are still in the early stages of development. Similarly, while market approaches to expansion are the subject of much discussion, they are also in the early stages of development.[596] It is not the intent of the Commission either to mandate a market approach to the exclusion of an executive decision by the RTO or to mandate any particular market approach.

Nevertheless, if any market-driven approach is to be successful, there must be accurate price signals that reflect the costs of congestion and expansion costs. As we stated in the NOPR, accurate price signals are the link between current usage and future expansion. Therefore, as discussed in more detail in Section III.E.2 Congestion Management, every RTO must establish a system of congestion management that establishes clear rights to transmission facilities and provides market participants with price signals that reflect congestion and expansion costs. In implementing its planning and expansion responsibility, an RTO must ensure that its decisions are not unduly discriminatory and produce efficient outcomes.

The Commission reaffirms its statement in the NOPR that independent governance of the RTO is a necessary condition for nondiscriminatory and efficient planning and expansion. While accurate price signals can signal the need for expansion, such expansion may not be achieved if an RTO operates under a faulty governance system (*e.g.,* a governance system that allows market participants to block expansions that will harm their commercial interests).

Multi-State Agreements and RTGs. The final rule fully recognizes the statutory authority of the states to regulate siting of transmission facilities. Currently, state and local governments and regulatory agencies have exclusive authority over the siting process. Therefore, an RTO's planning and expansion process must be designed to be consistent with these state and local responsibilities.

RTOs must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Commission encourages the development of multi-state agreements or compacts to review and approve new transmission facilities. This would expedite transmission construction and eliminate duplicative (and possibly conflicting) reviews by multiple states. To facilitate any voluntary actions taken by our state colleagues, we will require that the RTO planning and coordination system must be able to accommodate the possible emergence of new regional regulatory systems.

Existing RTGs have clear and prominent roles in transmission expansion decisions in which planning for transmission improvements are coordinated through collaborative processes. To avoid duplicative efforts, the RTO process must build on existing RTG planning processes. Over time, since the RTO will have ultimate responsibility for planning the entire transmission system within its region, we expect that the functions of an RTG will be assumed by an RTO to avoid unnecessary duplication of effort.

Three-Year Implementation. If the RTO is unable to satisfy the planning and expansion function when it commences operation, it must file a plan with the Commission with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. Recognizing that the planning and expansion function may require coordination among multiple parties and regulatory jurisdictions, we do not require this function to be in place at the initial operation of the RTO. We continue to believe that three years is a reasonable deadline for creating an operational planning and expansion system. Therefore, we will not extend this deadline or the requirement to file a plan with the Commission with an implementation timetable. This time period could be affected by the RTO's scope, the number of states and market participants, and implementation costs; however, the urgent needs of the electricity markets make us disinclined to extend these deadlines.

However, the delay should not stall the construction of new or enhanced facilities for which needs have been established, unless the RTO makes a positive decision that the facility is not in the best interests of the region. Delaying transmission expansion could result in significant market inefficiencies as well as unacceptable risks to reliability given the long regulatory and construction lead times required to build new facilities.

8. Interregional Coordination (Function 8)

In Order No. 888, the Commission identified eleven principles it would use to assess Independent System Operator (ISO) proposals submitted to the Commission.[597] One of these principles required that the ISO develop mechanisms to coordinate with neighboring control areas to ensure reliability and the provision of transmission services that cross system boundaries. The RTO NOPR encouraged transmission entities to consider ways to reduce impediments to transactions among themselves,[598] but a coordination requirement was not included explicitly in the RTO NOPR. Several commenters pointed out that there was no explicit coordination requirement proposed in the RTO NOPR and recommended including a function for RTOs similar to the coordination principle in Order No. 888.

[596] For example, TDU Systems and other commenters suggest that, by promoting competition for new construction, the RTO can minimize construction cost and also reduce its own risk profile. For example, an ISO in Victoria, Australia (VPX), which operates, but does not own transmission assets, uses competitive bidding for new transmission facilities. At the Regional ISO Conference in Richmond, Virginia on June 8, 1998, Raymond Coxe described how VPX's strategy resulted in a number of bidders competing for the right to build, own and operate new facilities. He concluded that the "result of this competition was a lower price to the consumers of Victoria than would have resulted from regulated transmission service by the largest incumbent provider." Transcript at 86, Docket PL98–5–006.

[597] Order No. 888, FERC Stats. and Regs. ¶ 31,036 at 31,730–32.

[598] FERC Stats. and Regs. ¶ 32,541 at 33,758.

Comments. Several commenters identify coordination with other regions as a necessary element that should be added more explicitly to the RTO functions.[599] These commenters express this need as either required to ensure reliability or necessary for bulk power markets to operate over sufficiently large areas. For example, NERC states that the need for such coordination effort has increased as the management of short-term reliability of the interconnected bulk power system and the operation of increasingly competitive bulk power markets have become inseparable. Accordingly, NERC recommends that an additional function be added to the final rule that requires RTOs to integrate their market interface practices and reliability practices. It identifies OASIS standards, information sharing with neighboring RTOs, ancillary services requirements, parallel path flows, transmission loading relief, and interregional congestion management, as practices and standards that need to be integrated.

Duquesne states that efficiencies can be realized from coordinating and developing a seamless marketplace. It recommends that the Commission require RTOs to coordinate and plan for seamless and uniform transmission rules, scheduling systems and procedures, and reliability standards. In addition, Oneok suggests that the Commission encourage neighboring RTOs to form reliability compacts under which loop flow and other issues involving interregional reliability impacts can be resolved.[600] Also, Wyoming Commission believes that the Commission should be flexible with respect to inter-RTO interaction and that it may be appropriate to address these issues later rather than in initial RTO filings.

Commission Conclusion. Coordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets. In the NOPR, we discussed several region-to-region coordination activities in connection with the parallel path, congestion management, and expansion planning functions. However, the comments persuade us to add a more general interregional coordination requirement as one of the minimum RTO functions.

We will require an RTO to develop mechanisms to coordinate its activities with other regions whether or not an RTO yet exists in these other regions.[601] If it is not possible to set forth the coordination mechanisms at the time an RTO application is filed, the RTO applicant must propose reporting requirements, including a schedule, for itself to provide follow-up details as to how it is meeting the coordination requirements of this function. We expect the RTO to work closely with other regions to address interregional problems and problems at the ‘‘seams’’ between the RTOs. Therefore, as recommended by NERC and others, we will add the following regulatory text to our RTO Final Rule functions:

(8) *Interregional Coordination:* The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

An RTO proposal must explain how the RTO will ensure the integration of reliability and market interface practices. An RTO may ensure the integration of these practices either by developing integration practices itself or by cooperating in the development of integrated practices with an independent entity that covers all regions or, for reliability practices, covers an entire interconnection. The term, interconnection,[602] refers here to any one of three large U.S. transmission systems. The Eastern Interconnection covers most of the area east of the Rocky Mountains in the United States and Canada. The Western Interconnection covers an area that is mostly west of the Rocky Mountains in the United States and Canada, as well as a small portion of Mexico. The Electric Reliability Council of Texas (ERCOT) Interconnection covers much of Texas.

This provision does not mean that all RTOs necessarily must have a uniform practice, but that RTO reliability and market interface practices must be compatible with each other, especially at the ‘‘seams.’’ RTOs must coordinate their practices with neighboring regions to ensure that market activity is not limited because of different regional practices.

We understand, as NERC pointed out in its comments, that the reliability and market interface practices are becoming highly interrelated. The reliability practices affect how markets interface with each other, and the market interface practices affect reliability. For example, TLR and congestion management are both used to unload an overloaded transmission interface, and these two practices must work together. We consider congestion management and TLR are best used as sequential steps to unload a line, with congestion management used first to unload a line in a market-oriented manner, and TLR used to unload a line in a fair manner when either congestion management is unavailable or an emergency condition requires immediate action. We therefore list below TLR as a reliability practice and congestion management as a market interface practice, understanding that these and other practices listed affect both reliability and markets.

The integration of reliability practices involves procedures for coordination of reliability practices and sharing of reliability data among regions in an interconnection, including procedures that address parallel path flows, ancillary service standards, transmission loading relief procedures, among other reliability-related coordination requirements in this Final Rule.

The integration of market interface practices involves developing some level of standardization of inter-regional market standards and practices, including the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures, as well as other market coordination requirements covered elsewhere in this Final Rule.

F. Open Architecture

In the NOPR, the Commission stated its commitment to a policy of ‘‘open architecture’’ and proposed to require that RTOs be designed so that they can evolve over time. The Commission noted that there should be no provision in any RTO proposal that precludes the RTO and its members from improving their organization to meet market needs.[603] The Commission sought comments regarding the open architecture policy in general and the flexibility needs of RTOs in particular.

Comments. Virtually all commenters support the NOPR's open architecture concept and recommend that an RTO have the ability to evolve over time as

[599] Many parties supported this requirement including NERC, Justice Department, NARUC, NASUCA, Oneok, PJM, Duquesne and Industrial Consumers.

[600] ISO–NE, NY ISO and PJM recently signed a memorandum of understanding concerning interregional coordination activities.

[601] This is similar to the existing ISO Principle #10 in Order No. 888 for single control area ISOs: ‘‘An ISO should develop mechanisms to coordinate with neighboring control areas.’’

[602] ‘‘Interconnection’’ is a term used by the North American Electric Reliability Council and others to refer to an interconnected alternating current transmission system. Engineering considerations require all generators connected to any one interconnection to operate in a coordinated manner, that is, synchronously.

[603] FERC Stats. and Regs. ¶ 32,541 at 33,753.

it gains operating experience.[604] They endorse the principle of flexibility to accommodate the changing needs of the market.[605] WEPCO notes that open architecture should permit flexibility and urges the Commission not to require an RTO to be the only control area operator in the region.[606] Ontario Power states that the open architecture policy should enable RTOs to accommodate Canadian entities in the future. Oglethorpe observes that open architecture policy would allow RTOs to utilize existing infrastructure and avoid high transition costs.

However, Central Maine and Southern Company argue that the flexibility implied by open architecture should not be used carte blanche. For example, there should be limits to an RTO's evolution process because transmission owners have some fundamental rights, such as: (1) The right to terminate their participation in the RTO; (2) the right to switch to another RTO; (3) the right to merge RTOs; (4) the right to recover their costs and a return on investment; and (5) the right to protect their assets and employees from damages and injuries.

LG&E states that the flexibility inherent in the open architecture concept should be applied fairly to all market participants, including those transmission owners that have already committed to existing or proposed ISOs. For example, a member of an existing ISO should be allowed to move to another RTO.

Industrial Consumers perceives a potential downside to the open architecture policy in that it may give existing IOUs a license to continue their opportunistic behavior rather than facilitating true market transformation. Therefore, Industrial Consumers argues that it supports the notion of flexibility inherent in the open architecture policy only in the absence of market power. Illinois Commission argues that the pace of evolutionary improvement of RTOs should not remain in the hands of vertically integrated utilities because their interest in structural change may not be consistent with the public interest.

Cinergy, EPSA and Georgia Transmission state that the flexibility implied by open architecture should not be used to support deviations from minimum characteristics and functions. However, CP&L believes that the proposed minimum characteristics and functions are too stringent and do not allow for much flexibility that a changing market needs.[607] Georgia Transmission supports the Commission's commitment to providing regulatory flexibility to allow RTOs to evolve.

Many commenters state that the open architecture concept is so broad that it will prevent stakeholders from developing meaningful RTO proposals. To bring some certainty to the negotiating parties to an RTO proposal, CP&L recommends that the Commission find that some necessary and reasonable limitations on modifications to RTOs are permissible, and these can be overridden only by unanimous consent or a supermajority vote.[608] MidAmerican states that the Commission should accept RTO proposals that contain stated limitations, such as a transmission owner's right to withdraw from an RTO. MidAmerican argues that such limitations are consistent with the Commission's open architecture policy and would prevent transmission owners from being discouraged to join RTOs. To promote certainty, Entergy notes that the Commission should establish a general policy of grandfathering previously approved RTOs and not altering their requirements except in extraordinary circumstances.[609]

Southern Company is concerned that RTOs could evolve in ways that are undesirable to the participants that initiated its formation. Therefore, it argues that the parties should have some assurance that certain key provisions of an RTO would not change in the name of RTO evolution. For example, functions, boundaries, transmission rate design, and allocation of transmission revenues should not be amended by the RTO except by vote of the transmission owners, at least for the duration of a specified transition period. Southern Company contends that the transmission owners will then know what they are ''getting into'' when they join an RTO.

Many commenters recommend that the Commission should not mandate the ultimate organizational form of the RTO given the electric industry's current state of structural flux and the uncertainty of the future. These commenters argue that the Commission's open architecture policy should encourage market participants to develop transmission institutions that are effective in meeting the needs of the marketplace. FirstEnergy and NU state that there is a range of organizational and functional forms—power pool (tight and loose): gridco, transco, marketco—which can accomplish the Commission's goal of improving the efficiency of the transmission grid, and only time and market forces should determine which form is best suited for a specific region of the country. Southern Company believes that there should be no requirement that would prohibit an RTO with no transmission ownership to transform into one that owns transmission (*i.e.*, change from an ISO to a transco).

PJM urges the Commission to clarify that RTOs can propose improvements to the RTO independently of its members to meet changing market needs. PSE&G is opposed to giving such authority to RTOs because it believes that the market participants rather than RTOs should drive changes in the structure and operation of electric markets.[610] Cal ISO recommends that the Commission's open architecture policy should support the creation of a structure that facilitates the addition of new participants, both within and outside of the existing RTO boundaries. Illinois Commission urges the Commission to modify the proposed paragraph 35.34(k) of proposed regulations to include an affirmative expectation that RTOs *will* change to meet new competitive market needs and to improve over time.

Commission Conclusion. As proposed in the NOPR, we adopt the principle of open architecture in order that the RTO and its members have the flexibility to improve their organizations in the future in terms of structure, geographic scope, market support and operations to meet market needs. We will require that the RTO design have the ability to evolve over time. In addition, we will provide flexibility to allow RTOs to propose changes to their enabling agreements to meet changing market, organization and policy needs.

[604] *See, e.g.,* APX, Arizona Commission, Cal ISO, Central Maine, Consumers Energy, CP&L, Conectiv, Desert STAR, DOE, Duke, Entergy, EPSA, FirstEnergy, Florida Commission, Georgia Transmission, Illinois Commission, Industrial Consumers, LG&E, NERC, NPCC, NSP, NU, NY ISO, Oglethorpe, PJM, Seattle, Southern Company, SMUD, SRP, TDU Systems, TEP, Tri-State and WEPCO.

[605] NSP states that the configuration of electric markets will be much different five or ten years from now.

[606] WEPCO notes that costs savings associated with creating large, efficient electricity markets will dwarf the savings attained by reducing the number of operators through control area consolidation.

[607] CP&L and Southern Company state that the Commission should establish basic RTO guidelines through a policy statement rather than by a rule. They contend that the rules under the NOPR are too prescriptive, and will stifle the development of new RTOs.

[608] CP&L notes that participants in Midwest ISO identified certain conditions that could be altered only by the transmission owners, including revenue distribution, pricing methodology and withdrawal rights.

[609] Entergy at 42.

[610] PSE&G Reply Comments at 6–7.

Open architecture will permit RTOs to evolve in several ways, as long as proposed changes continue to satisfy RTO minimum characteristics and functions. As a first example, open architecture will allow basic changes in the organizational form of the RTO to reflect changes in facility ownership and revised corporate strategies. As noted by Southern Company, an RTO that initially does not own any transmission facilities might acquire ownership of some or all of those facilities. With an open architecture design, the RTO's enabling agreements should anticipate and facilitate changes of this nature.

Second, open architecture design accommodates change in the geographical scope of RTOs. Electric markets are evolving quickly and future market trading patterns cannot be foreseen at the time of RTO organization. An open architecture design will enable an RTO to grow geographically and possibly merge with another RTO as changes in markets suggest a realignment of organizations to meet evolving market needs.

Third, market support is another area that benefits from open architecture design. For example, an RTO may not initially operate a PX to support a regional spot market, but later determine that the establishment of a PX would provide additional benefit in its region. With open architecture, the RTO can propose to add a PX function (or a PX monitoring function) to its design. Open architecture design ensures that such future developments that are beneficial to the marketplace are not foreclosed.

Fourth, open architecture design accommodates changing operational needs. Most commenters agree that, as RTOs gain operating experience, some changes will become necessary. Cal ISO acknowledges that it had to make significant changes to its tariff and operational practices as it gained operating experience, and it believes further modifications are likely to be identified as additional experience is gained regarding evolving competitive markets.

Finally, as noted in the NOPR, technological change make changes in RTO design inevitable and desirable. Accommodating that change will require flexibility and adaptability in the RTO organization; open architecture will permit design modification to keep pace with technology.

Some commenters argue that the flexibility implied by open architecture design should not be interpreted to mean unfettered ability on the part of the RTO to modify its structure or processes. We agree. Although under our open architecture policy the RTO will have the ability to propose whatever changes it believes are appropriate to meet the evolving needs of the RTO and the region, any such proposals or changes to existing agreements, which will be changes to the RTO's jurisdictional rate schedule(s) and contracts, will be subject to Commission review and approval under the FPA. The Commission will consider the merits of any changes to an approved RTO on a case-by-case basis. Interested parties will have the opportunity to comment on any such proposal. This process will enable all parties and the Commission to guard against proposed changes that are likely to stifle competition.

G. Transmission Ratemaking Policy for RTOs

We have concluded that the success of the Commission's efforts to have effective and efficient RTOs is dependent in large measure on the feasibility and vitality of the stand-alone transmission business. For that reason, and to promote economic efficiency, the RTO transmission ratemaking policies of the Commission are an important factor of RTO success. In light of the restructuring of markets and market institutions that is taking place, we now believe that it will be helpful to inform the industry about what we consider to be appropriate and inappropriate transmission pricing practices for RTOs, and about a framework for RTOs to propose efficient and fair pricing reform. Accordingly, we provide guidance below on a number of fundamental ratemaking issues.

We believe that it is critically important for RTOs to develop ratemaking practices that: eliminate regional rate pancaking; manage congestion; internalize parallel path flows; deal effectively and fairly with transmission owning utilities that choose not to participate in RTOs; and provide incentives for transmission owning utilities to efficiently operate and invest in their systems. In particular, the Commission encourages RTOs to develop and propose innovative ratemaking practices, particularly with respect to efficiency incentives. We therefore devote a significant portion of the discussion in this section of the Final Rule to performance-based regulation (PBR) and other RTO transmission ratemaking reforms.

In addition to the guidance offered here, we have added regulatory text (section 35.34(e)) with regard to PBR and other RTO transmission ratemaking reforms,[611] which now identifies a select list of innovative transmission rate treatments. The Commission will consider such innovative rate treatments for entities that file proposals under the new section 35.34 and that meet the minimum characteristics and functions required in the Final Rule. The Applicant must explain how the proposed rate treatment would help achieve the goals of RTOs, including efficient use of and investment in the transmission system and reliability benefits to consumers; provide a cost-benefit analysis, including rate impacts; and explain why the proposed rate treatment is appropriate for the RTO proposed by the Applicant. This means that filings under section 35.34(e) must be complete and fully explained; must demonstrate that the resulting rates are just, reasonable, and not unduly discriminatory or preferential; must identify how the rate treatment promotes efficiency and what benefits result; and must demonstrate that the rate treatment does not impede the RTO from meeting the minimum characteristics and functions required under this Final Rule. The Commission encourages properly developed transmission pricing proposals from RTOs that comply with the guidance set forth below and the amended regulatory text.

We agree with those commenters that urge the Commission to reform its transmission pricing policies to reflect new realities of the industry. For example, a number of commenters point to the unbundling requirements of Order Nos. 888 and 889, the vertical de-integration of generation and transmission for some utilities, the advent of wholesale and retail competition in energy markets, entry into markets of a range of new players, including independent generators and marketers, and other developments as a signal that the Commission's traditional cost-of-service ratemaking practices for transmission assets should be reevaluated. Some commenters suggest that the advent of competitive power markets necessitates a more robust transmission network as well as enhanced operating capabilities of the network, compared to the previous era of vertically integrated utilities providing service in monopoly franchise areas. They argue that the Commission's traditional transmission ratemaking practices are unlikely to support such a robust transmission network and enhanced operating capabilities.

[611] We have adopted and expanded the regulatory text proposed by Edison Electric Institute in its comments (*see* EEI, Appendix E).

To put our concerns about transmission pricing in perspective, the NOPR said that ''the Commission expects RTOs to reform transmission pricing, and in return we propose to allow RTOs greater flexibility in designing pricing proposals.'' [612] The NOPR also said that our willingness to provide flexibility in reviewing pricing proposals dates back to the Transmission Pricing Policy Statement, issued by the Commission in 1994. In the Policy Statement, we identified five principles that transmission pricing proposals should conform to, including the principle that pricing proposals should meet the traditional revenue requirement. In order that this principle not undermine innovative pricing proposals, the Policy Statement noted that non-conforming pricing proposals would be considered, but that such proposals would have to satisfy additional factors, *i.e.*, promote competitive markets and produce greater overall consumer benefits. In the five years since the Policy Statement was issued, we have approved five ISOs with innovative transmission pricing, but otherwise have received few innovative transmission pricing proposals. We believe that, as a general matter, sensible pricing reform that could promote competition and efficiency in other contexts will achieve maximum benefits only when applied on a regional, rather than a single-system basis. This is true because of the inability of single systems to capture such efficiencies, but sensible pricing reform is one of the efficiencies that will likely flow from RTOs. And while we do not think the Policy Statement has been an impediment to transmission pricing innovation, we now believe, based on the myriad comments we received, that the Commission should now provide greater specificity on appropriate transmission pricing reforms by RTOs.

The rationale for providing greater specificity on transmission pricing for RTOs and amending the regulatory text at this time is three-fold. First, we recognize that transmission pricing issues are some of the most complex issues facing the industry. Second, a potential barrier to the development of RTOs, at least RTOs that span multiple transmission systems, is the difficulty that stakeholders have had reaching consensus on transmission pricing. This is not surprising, given that transmission pricing reform to accommodate regional needs and usage patterns can affect what customers pay for transmission service and how transmission revenues are allocated among multiple owners of transmission within a region. Third, we are concerned that as we move to greater reliance on market forces, the incentives that market participants have to make efficient operating and investment decisions for both generation and transmission facilities are based in part on the price signals that flow from transmission pricing. That is, transmission pricing is a key determinant of the efficient operation of energy, ancillary service and balancing markets, and congestion management.

At the outset, we want to make clear that, contrary to the apprehensions of some commenters, the Commission is not proposing to ''bribe'' transmission-owning utilities to join an RTO. Rather, the Commission stated in the NOPR that it would consider innovative pricing proposals because we believed then, and now believe more strongly, that a reassessment of transmission pricing policy is warranted, given the fundamental changes in industry structure that have already occurred as well as those which may flow from the RTO Final Rule. In addition, as pointed out by Professor Joskow, delays in RTO formation occasion costs because of more limited competition in generation markets, and these costs may be avoided to the extent that the Commission considers transmission pricing reforms. Furthermore, as discussed below, since the costs of transmission are a small portion of total electric costs, getting transmission pricing right means that the industry will be able to capture significant net benefits from promoting competitive generation markets.

While the NOPR did not propose specific rules on transmission pricing reform, we believe it is now critical to provide further specificity to the industry. We recognize the need to establish clear and specific requirements for RTO development, provide certainty and clarity about our willingness to entertain transmission pricing reforms that are appropriate for RTOs, and assure utilities that they will not be penalized for RTO participation. To the extent consistent with ensuring that transmission rates are just, reasonable, and not unduly discriminatory, we believe transmission pricing disincentives to joining an RTO should be eliminated so that transmission-owning utilities will find RTO participation to be a dynamic business opportunity. Utilities that join RTOs should be accorded transmission pricing that reflects the financial risks of turning facilities over to an RTO and that reflects other changes in the structure of the industry. Those risks may increase or decrease in particular instances. At the same time, we wish to make clear that the Commission is very concerned about potential impacts of market restructuring on the customers in ''low-cost'' states, and the Commission therefore intends to monitor the effects of RTO formation on such customers, specifically the potential for cost-shifting effects of RTO pricing proposals.

Traditional transmission pricing approaches reflect the industry structure as it existed when Order No. 888 was issued: a vertically integrated industry where transmission systems were designed primarily to meet the needs of local loads. Our primary focus, both in terms of access and pricing was comparability; that is, all transmission users should receive access under rates, terms and conditions comparable to those the transmitting utility applies to itself to serve its own customers. RTOs reflect a somewhat different approach, in which the transmission system must also be designed and operated to meet the needs of regional markets. It is not unreasonable to expect that, as the transmission system is restructured to meet these changing needs, significant pricing reform may be needed as well. Indeed, since a properly developed RTO will be designing methods to support regional congestion management and regional expansion, transmission pricing reform is inevitable.

We caution that we do not view transmission pricing reform as a program designed for the sole purpose of enhancing the revenues of transmission owners at the expense of transmission customers. Nor are we abandoning the fundamental underpinnings of our traditional transmission pricing policies, *i.e.*, that transmission prices must reflect the costs of providing the service.[613] While many aspects of transmission pricing reform are labeled incentive pricing, many are aimed at eliminating disincentives to the efficient use and expansion of regional transmission grids to support emerging competition in generating markets.

We view transmission pricing reform, not only as an important component of how stand-alone transmission companies can become viable and efficient network businesses, but also as an important means for transmission-owning utilities which maintain ownership but cede control of their transmission assets to an RTO to capture

[612] FERC Stats. & Regs. ¶ 32,541 at 33,754.

[613] *See, e.g., Federal Power Commission* v. *Hope Natural Gas Co.,* 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co.* v. *Public Service Commission of West Virginia,* 262 U.S. 679 (1923).

the benefits of more efficient system operation and additional grid investment. We believe that the opportunities for pricing reform identified in this Rule should have no effect on an RTO's decision about how it will be structured. All RTOs, regardless of ownership structure, are therefore eligible to propose transmission pricing reforms that suit their strategic and economic objectives to the extent consistent with this Final Rule.

We also believe that the potential for any increase in transmission-related revenues available to transmission providers that are efficient and responsive in meeting the needs of their customers must be balanced by the potential for a decrease in profits if the transmission provider does not meet those needs. Moreover, a properly developed RTO can be expected to produce significant efficiencies, and we would expect that transmission owners, transmission customers and generation market participants will share in the economic benefits resulting from the efficient design and operation of the RTO.

As the industry begins the collaborative process of establishing RTOs, it is important that the Commission provide some certainty and specificity about the preferred types of transmission pricing reforms, and some certainty and specificity about the types of proposed transmission pricing reforms that appear more problematic. Accordingly, the remainder of this section discusses eight specific transmission ratemaking topics: pancaked rates; reciprocal waiving of access charges between RTOs; use of single system access charges; congestion pricing; service to transmission-owning utilities that do not participate in an RTO; performance-based regulation; other RTO transmission ratemaking reforms; and additional ratemaking issues.

1. Pancaked Rates

As described in the NOPR, the elimination of rate pancaking for large regions is a central goal of the Commission's RTO policy, and has been a feature of all five ISOs the Commission had approved. Rate pancaking occurs when a transmission customer is charged separate access charges for each utility service territory the customer's contract path crosses. The NOPR proposed that RTO tariffs not result in transmission customers paying multiple access charges to recover capital costs over facilities that it controls. The NOPR sought comments on the impact of the non-pancaked rate requirement on voluntary RTO formation because of abrupt rate changes. It also sought comments on how the regional configuration may relate to these potential rate changes.

Comments. The overwhelming majority of the comments favor the proposed prohibition on pancaked rates,[614] although some commenters express concern over cost shifting. Some commenters, such as Minnesota Power, suggest that the cost shifting effect of non-pancaked rates would discourage voluntary RTO formation.

Some commenters suggest alternative approaches to the strict non-pancaked rate described in the NOPR. For example, WPSC advocates the use of flow-based, distance-sensitive rates as a replacement for pancaked rates. Allegheny argues that removing rate pancaking can cause disruptive shifts in rates and revenue requirements which are solved only temporarily with transitional rates. Allegheny proposes its form of locational marginal pricing method to solve this problem. NSP favors non-pancaked rates but notes that rates for the high-voltage system that differ from those for the low-voltage system may be an effective long-term rate strategy. MidAmerican recommends that the prohibition against rate pancaking be changed to allow transmission owners to charge a home-zone rate based on local cost determination and a wide-area charge outside the home area. MidAmerican argues that this approach would minimize cost shifting. The pancaked rate prohibition would change to: ''promote wide-area transmission rates with due consideration to shifting of costs among transmission service providers and between state and federal delivery rates. Finally, Williams recommends that the Commission also consider other pricing methods such as those based on mileage or network usage and market-based rates, where possible, because it considers cost of service rates inefficient and unresponsive to the market.

A few commenters question an absolute prohibition against pancaked rates. AEP and Florida Power Corp. warn that a strict prohibition against pancaked rates may, at times, work against efficient solutions. There should not be a strict prohibition without regard to size or locational factors. Florida Power Corp. argues that this approach is consistent with the Commission's Transmission Pricing Policy Statement. Customers of both AEP and Florida Power Corp. dispute this view.[615] Southern Company notes that an absolute prohibition against pancaked rates may hurt retail customers whose rates are supported by transmission revenue. Transmission owners should be assured in the final rule that they will be able to recover their full revenue requirement in the face of any pancaked rate prohibition. The Commission should, according to Southern Company, also clarify that a prohibition against pancaked rates does not prevent the use of zonal or other distance-sensitive rates. Desert STAR argues that a single region-wide rate may not be appropriate in a large region with legitimate cost differences among companies, and suggests that license plate rates may mitigate cost shifting but will not always eliminate it.

Commission Conclusion. In the NOPR, we described the elimination of rate pancaking as a central goal of our RTO policy. After receiving comments on the subject, mostly in favor of the proposed prohibition, we affirm that the RTO tariff must not result in transmission customers paying multiple access charges to recover capital costs.[616]

Except for transactions within the ISOs now in place, transmission customers are faced with additional access charges for every utility border they cross. The distances need not be great to be assessed two, three or more access charges for a single transaction. This duplication can severely restrict the area in which generation can economically be secured. A main reason that an RTO can expand the marketplace for generation to a large region is that an RTO can implement non-pancaked rates for each transaction. A wider area served by a single rate means more generation is economically available to any customer which means greater competition for energy.

Some commenters warn that a blind adherence to non-pancaked rates can produce inefficiencies in some circumstances. Some argue that large distances and special conditions can add to transmission costs in a way not reflected in single system rates. They would leave open the option for distance-sensitive rates or completely new rate innovations that may not fit the strict definition of a non-pancaked rate. We are sensitive to some of these concerns, but we do not view a policy requiring non-pancaked rates as posing the problems that some commenters

[614] *See, e.g.,* NASUCA, PJM, LG&E, Industrial Consumers and WEPCO.

[615] *See* New Smyrna Beach and Coalition of Alliance Users.

[616] Section 35.34(k)(1)(ii). However, see the discussion below regarding service to transmission-owning utilities that do not participate in an RTO.

describe. We take this opportunity to reaffirm that we will continue to be receptive to distance-sensitive rates and other rate features that can be supported.

2. Reciprocal Waiving of Access Charges Between RTOs

The elimination of pancaked rates within an RTO was intended to increase the efficiency of trade in that region. The NOPR furthered that concept by encouraging RTOs to agree among themselves to waive access charges on a reciprocal basis for transactions that cross RTO borders. If accomplished, this would have the effect of increasing effective trading areas. The NOPR sought comments on how the Commission could facilitate reciprocal waivers of access charges, and whether there are other impediments to inter-regional trade.

Comments. A majority of the commenters support the concept of a reciprocal waiver of access charges to encourage inter-regional trade.[617] Of those who support waivers, some, including Duke and SRP, specifically recommend that waivers be voluntary. Some supporters of waiving access charges note that it is not just the pancaked charges that inhibit inter-regional trade but also variations in business practices and procedures between RTOs. These commenters [618] recommend that the Commission ensure that such incompatibilities not be allowed to hamper trade between RTO regions.

Several commenters, both supporting and opposed to waiver of access charges, warn that the waivers proposed in the NOPR can cause cost shifting. Duke argues that cost shifting can be remedied by the structure of the rate. DOE and First Energy also express concerns about cost shifting. Southern Company generally opposes waivers of access charges unless transmission owners' revenues are protected.

Some commenters oppose waiving access charges between RTOs for reasons other than cost shifting concerns. South Carolina Authority claims that reciprocal agreements between RTOs waiving access charges are discriminatory and that independent monitoring groups would be needed to prevent gaming of reciprocity agreements. CP&L argues that waivers create a bias to sell outside of the RTO. Tri-State proposes the use of distance-sensitive export pricing mechanisms instead of waivers.

PP&L Companies claim that inter-regional trade solutions should be arrived at through a collaborative effort of stakeholders. NECPUC and Desert STAR argue that the Commission should grant deference to participants' solutions for inter-regional trade. Florida Commission argues that the Commission should wait until intra-regional trade barriers are dismantled before dealing with inter-regional trade.

Commission Conclusion. We asked in the NOPR for comments on the policy of allowing RTOs to reach reciprocal agreements to waive access charges for transmission that crosses an RTO border. Most commenters supported the approval of such waivers and some asked the Commission to further support inter-regional trade by requiring uniform practices and procedures among RTOs. Some commenters maintain that incompatible or varying procedures between RTOs can be as dampening to inter-regional trade as multiple rates.

We will continue to encourage reciprocal waivers of access charges between RTOs as long as they are reasonable in terms of cost recovery, cost shifting, efficiency, and discrimination. We also encourage terms and procedures that are compatible from region to region to the extent appropriate. Accordingly, we have added an RTO function to integrate reliability and market interface practices with other regions, as discussed above.

3. Uniform Access Charges

Each ISO approved by the Commission has struggled with the problem of cost shifting among the various individual transmission owners that make up the ISO. A single access rate would mean that the customers of low-cost transmission providers would see a rate increase and high-cost transmission providers would be concerned about not meeting their revenue requirements. The potential for cost shifting has been a stumbling block for several regions seeking to establish regional transmission organizations.

The Commission has allowed a flexible approach to this problem, and in each ISO approved by the Commission to date the solution has been to adopt a ''license plate'' rate for a transitional period of five to ten years before moving to a single uniform access charge. A license plate rate provides access to the regional transmission system at a single rate although that rate may vary based on where the customer is located.[619] The NOPR proposed to continue to employ a flexible approach, including the use of license plate rates. The NOPR requested comments on whether the license plate approach is appropriate for the long term.[620]

Comments. A clear majority of commenters favors the use of license plate rates in general, with a nearly even split between those that would allow license plate rates only for a transitional period [621] and those that would allow them as a permanent feature.[622] Of the approximately 64 commenters who addressed this subject, only about nine were clearly opposed to license plate rates for either the long term or for a transitional period. And several commenters advocate the use of license plate rates as a general concept but did not address directly the NOPR's question concerning their long-term use.[623]

Several commenters argued that the use of license plate rates should be for a transition period roughly coincident with the phase-in of retail competition. For example, Duke argues that license plate rates avoid cost-shifting, and will therefore make it easier for companies to collect their retail revenue requirements in jurisdictions without retail competition, where state regulators may disallow higher transmission rates.

Commenters that support license plate rates as a long-term solution argue that license plate rates are an aid to RTO formation.[624] SoCal Edison claims that license plate rates avoid cost shifts, are administratively more efficient, provide a basis for efficient transmission operation, and provide incentives for system expansion. SoCal Edison favors their use in the long term.

Of those opposed to license plate rates in general, some suggest a different pricing methodology. CMUA prefers an integrated, two-part rate. The first part of the rate reflects the revenue requirement of the overall RTO (principally above 200 kV) and the second part reflects the local systems to the extent used. CMUA argues that license plate rates do not follow the rules of cost causation, do not promote needed enhancements and do not promote comparability in rates. Minnesota Power recommends a two-part rate with a demand component to

[617] *See, e.g.,* Sithe, WPSC, Minnesota Power, Ohio Commission, and Midwest ISO Participants.

[618] *See, e.g.,* Ontario Power and Oregon Office.

[619] Consider that registering a car in one state, paying that state's fees, and obtaining a license plate from that state, allows that car to be driven on the roads and highways of all other states.

[620] FERC Stats. & Regs. ¶ 32,541 at 33,754.

[621] *See, e.g.,* Montana Commission, Oglethorpe, Tri-State, FirstEnergy, Alliance Companies, AEP and DOE.

[622] *See, e.g.,* Allegheny, Industrial Consumers, Northwest Council, APS, Desert STAR and SPP.

[623] *See, e.g.,* Kentucky Commission, Gainesville, Big Rivers, Puget and Ontario Power.

[624] *See eg.,* East Kentucky and PJM.

collect fixed costs and a variable component for losses. WPSC advocates the use of flow-based, distance-sensitive rates rather than license plate rates. APPA claims that license plate rates do not go far enough. A four part approach is suggested in their place: assure recovery of revenue requirement; honor existing contracts and phase in regional rates; sub-functionalize the grid by voltage; and, once trusted RTOs are in place, allow congestion rates above embedded costs and non-congestion rates below, all subject to a revenue requirement true-up. RECA recommends that zones for transmission access charges be formed based on cost and other differences, not on existing service areas. SMUD claims that Cal ISO's license plate rate encourages inefficient operation.

Some commenters provide more general reactions to the cost shifting problem. Wyoming Commission recommends that the Commission not codify a specific approach to license plate rates and other measures with cost-shifting ramifications but rather defer to regional and state processes to establish guidelines within a region. PSNM is concerned about the impact of the loss of existing contracts on its license plate rate calculation. Manitoba Board is concerned about shifting costs to low-cost, transmission-dependent areas. Platte River does not want its low costs averaged with higher cost systems. United Illuminating encourages the Commission to continue its flexibility in permitting different approaches in the recovery of sunk costs. Aluminum Companies argues that the Commission needs to offer more guidance on cost shifting and that rate increases due to cost shifting should be constrained to the benefits involved. Further, cost shifts should not be allowed unless competition is fostered.

Commission Conclusion. We conclude that the Commission should continue to provide flexibility with respect to RTO proposals for allocation of fixed transmission cost recovery. The Commission will permit RTO proposals to use license plate rates, as defined above, for several reasons. First, commenters overwhelmingly support the use of license plate rates, and demonstrated convincingly that problems associated with cost-shifting are not easily resolved by means other than the use of license plate rates. Second, the Commission is concerned that the potential for cost-shifting could act as an impediment to RTO formation, thereby denying all stakeholders the benefits that come from RTO membership.

Moreover, although license plate rates are not necessarily an ideal method for fixed cost recovery, we note that all ISOs have sought approval from the Commission for license plate rates, at least during their startup phase. No commenter has provided convincing evidence that the use of license plate rates by existing ISOs produces significant harms, although several commenters suggest various rate designs, including multi-part rates, as alternatives to license plate rates.

Although commenters overwhelmingly support the use of license plate rates, they are split on whether such rates should be used only for a transitional period, or whether the Commission should allow them as a permanent feature. This is a difficult issue. On the one hand, we are reluctant to require RTOs to suspend use of license plate rates after some arbitrary date certain at which time they will be required to transition to single system access rates; on the other hand, we are reluctant to announce generically that license plate rates may be a permanent feature of an RTO. Furthermore, the use of license plate rates could depend on idiosyncratic facts, *e.g.,* the geographic makeup of the RTO, or the transmission cost differences in various subregions of the RTO.

We therefore believe that it is appropriate to allow RTOs to propose the use of license plate rates for a fixed term of the RTO's choosing. However, RTOs that propose the use of license plate rates must make clear how transmission expansion will be priced, that is, whether license plate rates or some other mechanism will be applied to the cost of new transmission facilities, and how such pricing affects incentives for efficient expansion. In addition, we will require that before the end of the fixed term, the RTO must complete an evaluation of fixed cost recovery policies based on the factual situation of the particular RTO, and file with the Commission its recommendations on any changes that should be instituted. We emphasize that we are not requiring that the RTO continue or abandon the use of license plate rates at that time, but we will require the RTO to justify its choice to continue or discontinue using license plate rates, or otherwise change the method for fixed cost recovery. We believe that this approach provides participants in RTOs significant flexibility, and is consistent with the principles articulated in the open architecture requirement for RTOs.

4. Congestion Pricing

Congestion pricing and congestion management are closely related. Comments on these issues have been treated jointly, and are summarized above in the discussion of congestion management.

Commission Conclusion. With respect to congestion pricing, the Commission emphasized that it intends to be flexible in reviewing pricing innovations, and sought comments on what specific requirements, if any, best suited the Commission's RTO goals. A number of commenters agreed with the Commission's conclusion in the NOPR that ''markets that are based on locational marginal pricing and financial rights for transmission provide a sound framework for efficient congestion management.'' [625]

We reemphasize the basic principles for congestion pricing articulated in the NOPR, *i.e.,* that proposals should ''ensure that the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and limited transmission capacity should be used by market participants that value that use most highly.'' [626]

We recognize that congestion pricing, especially when complex problems associated with parallel path flows are addressed, is in its infancy. Rather than prescribe a specific method, we encourage experimentation with reasonable congestion management techniques. We would expect that such experiments be consistent with the open architecture requirements of the rule, and that information from such experiments be made widely available to all interested parties, so that other RTOs can learn from each others' experience.

5. Service to Transmission-Owning Utilities That Do Not Participate in an RTO

The Commission asked commenters to discuss the treatment by an RTO of a non-participating transmission owner in a region if the transmission owner does not participate in its region's RTO.[627] For example, we asked whether it would be appropriate to allow RTO members to provide transmission service at individual system rates to non-participating transmission owners located in the RTO region thereby denying non-participants the benefits of non-pancaked transmission rates.

Comments. Of those commenters that generally support the proposed strategy,

[625] FERC Stats. and Regs. ¶ 32,541 at 33,742.

[626] *Id.* at 33,754–55.

[627] *Id.* at 33,759.

most argue that non-participants should not enjoy the benefits of non-pancaked rates.[628] PG&E submits that the reasoning the Commission applied in Order No. 888 applies here (*i.e.,* in Order No. 888, the Commission rejected the claim that a reciprocity requirement required explicit Commission jurisdiction over the transmission customer finding that, as a matter of fairness, a public utility providing open access through a non-discriminatory tariff deserved the right to obtain comparable access over the transmission systems of its customers). Empire District is particularly concerned that utilities on the border of an RTO may receive many advantages of the RTO without accepting any of the burdens of participation, yet at the same time make it more difficult for competitors to service its load by staying out of the RTO.

Other commenters are conditional in their support. For example, Oneok wants the Commission to draw a hard line on non-participation and be willing to employ negative incentives; however, Oneok points out that denial of non-pancaked rates will be more costly to marketers and consumers. South Carolina Authority suggests that the Commission consider the extent to which the transmission owner is actually able to participate in an RTO before permitting denial of RTO service under non-pancaked rates. In the case of publicly owned utilities, there may be restrictions in the enabling act or charter, the applicable state constitution or the utility's bond covenant that effectively prohibit it from participating in a particular RTO. This would also apply if the RTO is not the product of the ''region's RTO'' involving all stakeholders in the designated region but is a business entity designed to advance the financial objectives of particular sponsors. Similarly, SPRA argues that, in the event that it is unable to immediately join an RTO, the RTO should recognize that SPRA has an OATT that provides for comparable treatment to the RTO. And New Smyrna Beach states that, although denial of non-pancaked rates to nonparticipants has merit, it may be a moot issue in Florida where FP&L's transmission is so extensive that pancaked rates would be a more costly alternative for marketers and consumers of electricity.

Other commenters believe the proposal is a flawed concept or otherwise oppose it. Avista and PPC argue that it is not appropriate to allow an RTO to provide transmission service at individual system rates to non-participating transmission owners as such a policy would deny them the benefits of non-pancaked rates and defeat the central goal of its proposal. Metropolitan concurs that non-participating transmission owners should share in the benefits of non-pancaked rates. Southern Company and CP&L claim that the Commission cannot punish utilities that find it in the best interests of their stakeholders not to join an RTO. SMUD believes that RTOs must provide nondiscriminatory access to transmission it controls at cost-based rates to all customers, since they contribute to the RTO's cost recovery. SMUD argues that the Commission, through its NOPR has, in essence, found that pancaked rates are not just and reasonable and that they should be corrected; thus, the Commission cannot allow an RTO to charge pancaked rates in violation of the FPA section 205 prohibition on unjust or unreasonable rates.

Snohomish, Turlock, Big Rivers and Dairyland all make similar arguments—charging higher pancaked rates to utilities that do not participate in the RTO is patently unfair, violates the Commission's duty to eliminate discriminatory rates, and would penalize consumers of customer-owned utilities who have no practicable choice about whether to participate in the RTO. Dairyland says that this could open the door to creation of RTOs that purposely do not accommodate non-public utilities. SRP posits that imposition of pancaked rates on non-participants in an RTO would effectively turn the Commission's stated policy goal of voluntary participation into an RTO mandate inviting years of litigation.

Two state commissions question the effectiveness of pancaked rate sanctions against non-participants. Indiana Commission contends that a recalcitrant utility may not perceive pancaked rates as detrimental and may not feel compelled to join an RTO. Illinois Commission feels that imposition of penalties involving restricted access to RTO transmission rates would either be self-defeating for the Commission or detrimental to the electricity consumers of the affected utility. In its view, the solution to this conundrum is for the Commission to abandon its unworkable voluntary approach to RTO participation, and utilize its authority under FPA sections 205 and 206 and examine its authority under FPA sections 202(a), 211 and 212 to mandate participation. However, Nevada Commission submits that the Commission must ensure that a transmission-owning utility that refuses to join an RTO should not be allowed to derive any economic benefit from the existence of RTOs.

ISO commenters have diverse views on this issue. Desert STAR argues that a blanket ban on prohibiting a party that does not join an RTO from deriving any benefit from the RTO whatsoever may be too broad an approach. NYPP, citing *Associated Gas Distributors* v. *FERC*[629] and *Richmond Power & Light* v. *FERC*[630] for the proposition that the Commission cannot achieve indirectly what it cannot do directly, submit that the Commission cannot impose any coercive measure on or deny benefits to utilities that do not participate in an RTO. In addition, NY ISO argues that previously approved ISO's transmission-owning members should be eligible for whatever RTO participation incentives and benefits are ultimately adopted in this proceeding. On the other hand, PJM/NEPOOL Customers support denial of non-pancaked transmission rates to nonparticipants.

Canadian entities generally oppose imposition of pancaked rates against non-participants. Canada DNR contends that a decision not to participate in an international RTO by a Canadian jurisdiction should not place entities in that jurisdiction engaged in trade with the U.S. at a disadvantage relative to U.S. RTO participants. BC Hydro concurs that the decision to join an RTO should not be made a prerequisite for participation of Canadian provincial utilities or their affiliates to participate in the U.S. electricity market. CEA observes, however, that Canadian utilities see access to the U.S. market as a significant business opportunity that requires a transparent and open bulk transmission system operating in both directions. Grand Council *et al.* submits, however, that applying no penalties or incentives to Canadian utilities, while giving them unfettered access to U.S. markets without being subject to corresponding obligations, is inconsistent with the RTO concept. And H.Q. Energy Services submits that, if the Commission decides not to require RTO participation, it should strongly encourage voluntary participation by denying certain benefits such as the use of the system-wide tariff to nonparticipants.

Commission Conclusion. Regarding the question raised in the NOPR about whether a non-participating transmission owner in an RTO region should receive all the benefits of the RTO in its region, we share the concerns

[628] Montana-Dakota, Allegheny, PG&E, Tri-State, PNGC and Empire District.

[629] 824 F.2d 981, 1024 (D.C. Cir. 1987).

[630] 574 F.2d 610, 620 (D.C. Cir. 1978).

of most commenters that transmitting utilities may receive the benefits of an RTO in its region without accepting any of the burdens of participation in the RTO. Accordingly, where a transmission customer of an RTO or the customer's affiliate owns, controls or operates transmission in the RTO's region, and is not participating in that particular RTO, we intend to permit that RTO to propose rates, terms, and conditions of transmission service that recognize the participatory status of the customer.

We do not intend that every such proposal will necessarily be accepted by the Commission. Each RTO must justify any proposal on a case-by-case basis. The proposal should recognize the various situations of non-participating transmission owners. As pointed out by commenters, some transmission owners may face legal obstacles to participation that may need to be taken into account in the proposal.

It is not our intent to permit an RTO to apply such a proposal to a non-participating transmission owner in another region. As discussed above, Empire District expressed concern about whether this provision would apply to a non-participating owner ''on the border'' of an RTO. We would permit an RTO to argue that the non-participant should be part of its RTO region based on engineering or other objective criteria.

An RTO will provide several benefits for parties in the region, including elimination of individual system rates. We asked in the NOPR whether it would ''be appropriate to allow RTO members to provide transmission service at individual system rates to non-participating transmission owners *located in the RTO region.*'' (emphasis added) [631] SMUD argues that the Commission in its NOPR has found, in effect, that individual system rates are not just and reasonable and so cannot allow transmission-owning utilities in an RTO to charge individual system rates.

SMUD is incorrect. We have not made a generic determination that individual system rates are not just and reasonable in an RTO region. A non-participating public utility transmission owner in an RTO region may itself file a single company rate and argue that it is just and reasonable for use by its neighbors who join the RTO.

Instead of making a generic determination about these matters, we will permit an RTO and its transmission-owning public utility members to make the case that it is just and reasonable to charge individual system rates to a transmission customer who is a non-participating transmission owner in its RTO region. We will decide each RTO proposal on its merits.

6. Performance-Based Rate Regulation

The NOPR suggested that, once RTOs are formed, performance based regulation (PBR) can facilitate good grid operation.[632] We noted that PBR can incorporate price/revenue caps, price incentives, or performance standards. The NOPR sought comments on how PBR should be applied to an RTO and whether it should be voluntary.

Comments. The vast majority of commenters favor PBR of some form to promote efficient operations by RTOs.[633] And most commenters that favor PBR specifically state that PBR should be voluntary for RTO participants.[634]

Professor Joskow recommends that the Commission promote the view that PBR will eventually be required. He suggests that there is sufficient experience with PBR, such as in England and Wales. He argues that PBR should be based on a standard price cap that focuses not only on direct transmission service costs, but also focuses on the cost of congestion management, losses, ancillary services, reactive power, and connection of new generators. EEI notes that a price cap, based on a reasonable ROE revenue requirement, is the most widely used method. EEI argues that price caps reduce rate cases, give an incentive to improve productivity, and share productivity savings with customers. Brattle Group does not propose a specific PBR scheme but says that, at this point, approval should be case-by-case. Care should be taken that a PBR is not based on a single element, causing distortions elsewhere.

Other supporters have specific comments regarding the implementation of PBR. Entergy recommends that the Commission provide more specific guidance on the use of PBR. DOE warns that PBR should not be allowed to prevent a PMA that is a part of an RTO to under-recover its revenue requirement. New Smyrna Beach and Oneok only support PBR if there is a downside as well as an upside potential associated with transmission performance. Allegheny states that the Commission must settle on a definition of performance, the performance criterion should be economic reliability, the owner must have an opportunity to recover investment, the Commission should recognize that some aspects of performance will be outside of the control of the RTO, and the particular PBR rate calculation should be considered on a case-by-case basis.

A number of commenters recommend that PBR not be instituted immediately upon the formation of the RTO. California Board, Trans-Elect, and WPSC maintain that time is needed to establish base year benchmarks. PG&E and APPA say that PBR should be set aside until the RTO is up and functioning and Arkansas Consumers and Wyoming Commission argue that the RTO should first demonstrate that it can and will provide reliable and non-discriminatory service before PBR is established.

At least eight commenters were opposed to PBR for RTOs as a Commission policy. Industrial Consumers, Williams, and CMUA do not think that PBR can be effective in promoting efficiency in the operation of RTOs. Salomon Smith Barney and East Texas Cooperatives believe that RTOs will be able to game the system and take advantage of PBR. PJM/NEPOOL Customers, Lincoln, and NASUCA argue that PBR should not be allowed for RTOs because they are unnecessary. NASUCA is also skeptical of PBR for RTOs because some areas where performance is important are not under the RTO's control. NJBUS argues that PBR will not put a stop to transmission discrimination.

NEPCO *et al.* disagree with those commenters who oppose PBR.[635] PBR is effective, as shown in the United Kingdom, and they are not ''bribes'' given freely to transmission owners. Enron/APX/Coral Power does not agree with NASUCA and California Board that there is not enough experience on which to base PBR. According to Enron/APX/Coral Power, there is a large amount of experience in regulating transmission plus a lot of experience with the ramifications of EPAct.

A few additional commenters neither strongly support nor oppose PBR, but offer specific comments about PBR use. Project Groups recommends that the Commission construct a way to de-couple revenues from transmission rates so that efficient transmission service rather than total throughput determines revenue. Florida Commission states that questions as to the advisability and particulars of a PBR mechanism should be left to regional solutions that have the endorsement of the state regulatory

[631] FERC Stats. & Regs. ¶ 32,541 at 33,759.

[632] *Id.,* at 33,755.

[633] *See, e.g.,* EPSA, PJM, Los Angeles, Georgia Transmission, Illinois Commission, Pacific Corp and Desert STAR.

[634] *See, e.g.,* Florida Power Corp., MidAmerican, Tri-State, FirstEnergy, Alliance Companies, Duke and PGE.

[635] *See, e.g.,* APPA, Minnesota Power and CMUA.

bodies. Big Rivers states that PBR is inappropriate for cooperatives and public power utilities. WEPCO believes that RTOs should be not-for-profit and that PBR should be available only to the for-profit transmission owner. Metropolitan is concerned that PBR might cause RTOs to neglect needed expansions and upgrades and jeopardize reliability.

Commission Conclusion. At the outset, we think it is important to emphasize that PBR is far from a new concept. Over the last 10 to 20 years, a significant amount of research, primarily by economists, has been done regarding the conceptual basis of, and efficient designs for, PBR.[636] This research addresses its use in the electric utility industry as well as other regulated industries. It is also important to note that the Commission has been receptive to PBR proposals, at least since issuance of the Policy Statement on Incentive Regulation in October 1992. In that Policy Statement, we provided guidance to public utilities as well as natural gas and oil pipelines considering proposing some form of PBR.[637] Although the Policy Statement invited public utilities to develop and file incentive regulation proposals, the Commission has not received any proposals from public utilities.[638]

The Commission's current interest in PBR stems from the proposition that PBR will allow the Commission to rely on market-like forces, to the maximum extent possible, to create incentives for RTOs to efficiently operate and invest in the transmission system. This does not mean that we expect that transmission services will be provided in competitive markets any time soon, or at all. We recognize that transmission service will retain most or perhaps all of the characteristics of a natural monopoly for the foreseeable future, and that some type of explicit price regulation will therefore be required to prevent monopoly abuse. But we believe that PBR, especially if accompanied by explicit and well-designed incentives, may provide significant benefits over traditional forms of cost-of-service regulation. We believe this view of PBR is entirely consistent with other initiatives taken by the Commission, such as Order Nos. 888 and 889, to promote competitive power markets, and given the impracticality of competitive transmission markets, to rely on market-like forces to the maximum extent possible.

Before providing further specificity on PBR, it is useful to restate the overarching concerns of commenters. A large number of commenters support the use of PBR, and many of them, as discussed above, believe that PBR and other forms of incentive regulation will significantly enhance the incentives RTOs have to make efficient operating and investment decisions. For example, Professor Joskow notes:

> It is very important for the Commission to adopt regulatory mechanisms that provide transmission owners and operators with powerful economic incentives to operate transmission networks efficiently and to invest the resources necessary to expand their capabilities efficiently. These incentives should be an integral component of a performance-based regulatory (PBR) framework for the regulation of transmission rates that rewards transmission owners for achieving these objectives and penalizes them for failing to do so.[639]

On the other hand, a somewhat smaller group of commenters, mostly transmission customers, oppose the use of PBR. They express doubts about whether PBR will provide good incentives for RTOs to operate and invest efficiently. They are also concerned that PBR design is so difficult that RTOs will easily game the system, which will likely result in higher revenues for RTOs and therefore higher prices for transmission services for all transmission customers.

Commenters describe a wide array of PBR mechanisms, including some relatively unsophisticated proposals and others which are analytically complex. For example, a number of commenters have proposed that the Commission entertain transmission rate moratoriums, *e.g.*, where transmission rates are locked into their current levels for a limited period of years. To the extent the transmission provider can achieve any transmission costs savings, these would be retained by the transmission provider. In this sense, it falls within the concept of PBR.

It is argued that this rate treatment may promote the establishment of independent transmission companies because it provides the certain revenue stream that is needed to obtain financing for the purchase of transmission systems from existing owners. It is also argued that this approach is analogous to a hold harmless commitment for existing customers which may simplify the efforts of those state regulators who value transmission rate certainty during their conversion to retail choice. This approach would also reduce litigation at the Commission during the moratorium.

Finally, if the rate level selected takes into account the existing transmission component of bundled retail power rates, it addresses the concern expressed by many that one deterrent to participation in RTOs is the fear and uncertainty that transferring retail transmission services from state to Commission jurisdiction leads to reduced revenues.

Other commenters suggest that the essence of PBR is to set cost and performance benchmarks and then reward or penalize an RTO based on performance relative to those targets. Clearly, such an approach presents significant analytical challenges. Ideally, an RTO's cost and operating performance can be compared with other, similar entities. One benefit of setting such targets is that it overcomes the asymmetric information problem, *i.e.,* a transmission service provider will usually have better knowledge of the potential efficiency gains than will regulators. Benchmarking performance helps reduce the information imbalance.[640]

We have carefully considered all of the comments about PBR. We conclude that the Commission should encourage RTOs to consider use of PBR, although we recognize the difficult analytical challenges that RTOs will face. To facilitate such consideration, we are providing additional specificity on PBR. We address several threshold procedural issues, and articulate additional design principles that should provide a framework for RTO consideration of PBR.

[636] *See, e.g.,* Paul Joskow and Richard Schmalensee, Incentive Regulation for Electric Utilities, *Yale Journal of Regulation,* Vol. 4 at 1–49 (1986); Sanford Berg and Rajiv Sharma, Techniques for Assessing Firm Efficiency, University of Florida Public Utilities Research Center Working Paper (June 1999); Peter Navarro, Seven Basic Rules for the PBR Regulator, *Electricity Journal* at 24–30 (April 1996); G. Alan Comnes, Steven Stoft, *et al.*, Six Useful Observations for Designers of PBR Plans, *Electricity Journal* at 16–23 (April 1996); Lorenzo Brown and Ingo Vogelsang, Incentive Regulation: a Research Report, Federal Energy Regulatory Commission, Office of Economic Policy, Technical Report 89–3 (1989); and Jean-Jacques Laffont and Jean Tirole, A Theory of Incentives in Procurement and Regulation, MIT Press (1993).

[637] The Policy Statement articulated five regulatory standards: (1) incentive ratemaking must be prospective; (2) participation must be voluntary; (3) incentive mechanisms must be understood by all parties; (4) benefits to consumers must be quantifiable; and (5) quality of service must be maintained.

[638] We note that PBR mechanisms have been widely used by state regulators and the FCC as applied to the U.S. telecommunications industry. *See, e.g.,* John Kwoka, Implementing Price Caps in Telecommunications, *Journal of Policy Analysis and Management,* Vol 12, No 4 at 726–52 (1993).

[639] Professor Joskow at ES–iv.

[640] We note that there have been some early attempts to compare the relative cost and performance of ISOs in the U.S. *See, e.g.,* California ISO, ''A Comparative Analysis of Operating ISOs in the United States'' (Oct. 15, 1998).

A first threshold issue is whether the Commission should require that RTOs use PBR or whether it should be voluntary. There is almost no support for making PBR mandatory, and we therefore will not require RTO filings to include PBR proposals, although we encourage such proposals.

A second threshold issue is what types of RTOs are eligible for PBR. As discussed above, some commenters argue that PBR is not appropriate for cooperatively-owned and publicly-owned transmission owning utilities. Similarly, other commenters argue that PBR is appropriate only for profit-making RTOs. We conclude that, although the application of PBR may vary according to the type of RTO, there is no reason to limit the applicability of PBR to certain members or types of RTOs. The Commission welcomes RTO filings with PBR proposals from any source. For example, in the context of an ISO or a tiered ISO/transco that has been described by some commenters, the activities that contribute to performance may be shared between the RTO and the transmission owners. This does not invalidate the use of PBRs; however, the RTO design would simply ensure that the rewards and penalties associated with activities performed by transmission owners flow through to the owners to achieve the desired result.[641] In addition, we see no impediment to the use of PBR to provide incentives for efficient behavior by non-profit RTOs. We note that some existing ISOs have in place performance incentives for some of their managers, and such an incentive scheme may have application for RTOs which do not own the transmission assets they control.

A third threshold issue is how PBR proposals will be formulated and when they will be filed. The Commission recognizes that PBR design involves highly complicated issues, and that there is the possibility that a bad PBR proposal can result in lower quality transmission service, at higher costs, compared with service that might prevail under traditional ratemaking practices. One key element in the process of designing a PBR proposal would be to ensure adequate input from all stakeholders. We believe that the best PBR designs will emerge when all stakeholders have an opportunity for input, even if a filed PBR design does not represent full consensus. We therefore conclude that RTOs that wish to implement PBR need not necessarily file the PBR proposal at the time the RTO makes its compliance filing if more time is needed to negotiate among stakeholders the details of a well-designed PBR. Some commenters suggest that an additional consideration in allowing delayed filings of PBR is the need to evaluate operating experience of the RTO before appropriate benchmark measures for PBR can be developed.

The Commission also believes it is appropriate to provide additional specificity on what constitutes good PBR design. We continue to endorse the regulatory standards included in the Incentive Regulation Policy Statement, described above. And we note that in some regions, certain types of PBR mechanisms may be better suited than others. For example, where there are already state-imposed rate moratoriums, continuation of such programs after RTO formation may be an appropriate PBR approach. Alternatively, a transmission rate moratorium based on the existing rate level may be appropriate for a transitional period during RTO formation.[642] Similarly, in an area that has experience with a particular performance-based mechanism, extension and perhaps refinement of such a program after RTO formation may be the most appropriate policy.

We encourage RTOs to file fully documented PBR proposals that are consistent with the amended regulatory text. PBR proposals should include a detailed explanation of how the PBR mechanism will work, as well as all of the information necessary for the Commission and all market participants to evaluate the benefits and costs of implementing the PBR mechanism.

Based on the comments we received in this docket, as well as our understanding of international[643] and state experience with incentive regulation, we expand on the considerations for PBR addressed in the amended regulatory text by offering the following additional principles for RTOs to consider in designing PBR proposals.

PBR should not be applied piecemeal. To the extent possible, PBR programs should focus on the entire operation of the RTO, rather than smaller parts of the operation. Commenters caution that PBR programs that focus narrowly, *e.g.,* only on the cost aspects of RTO operations, may result in inattention by the RTO to the quality of service offered. Similarly, a focus on only one aspect of costs, *e.g.,* short-run costs, may result in reduced costs for that single aspect, but higher total costs for the RTO.

PBR should encompass both rewards and penalties. Although some PBR designs employ either rewards or penalties, but not both, most commenters suggest, and the Commission agrees, that the most effective and most fair designs will likely encompass both. One rationale for this is that it is not always clear what incentives an RTO will respond to, and therefore the prospect of higher revenues as well as the threat of lower revenues may induce an RTO to provide the best possible performance. An additional rationale is that under the FPA, the Commission is required to set rates for transmission service at just and reasonable levels. To the extent that rates may vary within a range—both up and down—as a function of RTO performance, this statutory requirement may be better satisfied.

PBR rewards and penalties should create incentives for an RTO to make efficient operating and investment decisions, and should not compromise system reliability. A significant concern in any PBR application is the possibility that incentives will distort RTO decisionmaking. For example, commenters caution that an RTO may manage congestion through a combination of generation redispatch and investment in transmission infrastructure, and that poorly designed PBR mechanisms could distort RTO decisionmaking toward the most profitable, rather than the least-cost, solution, or toward an approach that inappropriately reduces system reliability. An additional concern is that PBR mechanisms may create bias with respect to the trade-off between investment in generation and transmission, or in siting generation and transmission facilities in the most efficient places on the grid.

The benefits of PBR should be shared between the RTO and its customers. The Commission believes that as a matter of fairness, the efficiency gains occasioned by PBR should be shared. This will involve difficult analytical issues, including identifying efficiency gains,

[641] For example, PJM states that it can facilitate the application of PBRs to its transmission owners by using the stakeholder process to set the performance parameters and, once the parameters are in place, to independently evaluate the transmission owners' performance and apply the PBR.

[642] As noted *infra,* this is one of the pricing reforms that will be available for a defined transition period during which RTOs are being established.

[643] We note that a PBR system that uses a variant of price cap regulation of the National Grid Company has been in use for nine years in England and Wales. More recently, the price cap has been combined with a separate incentive mechanism that focused on reducing congestion on the grid. Since this is the longest-running PBR targeted to grid operations, we encourage any RTO that intends to propose PBR to examine the strengths and weaknesses of the British approach.

measuring them, and determining the effect of sharing such gains on the strength of the incentives faced by the RTO. The Commission does not believe it would be appropriate to specify the exact distribution of such gains, as such a decision is better left to negotiation by all stakeholders.

To the extent possible, the rewards and penalties should be prescribed in advance based on known and measurable benchmarks. PBR designs involve an inevitable trade-off between simplicity and administrative ease on the one hand, and the potential benefits of the program. Although relatively simple designs such as rate freezes provide significant incentives for an RTO to reduce its costs, they produce relatively limited incentives to maintain reliability, promote service quality, or manage congestion. PBR mechanisms that benchmark an RTO's performance, either to its own historical performance, to industry performance indices, to some normative goal, or to a combination of these, may be designed to provide incentives for more efficient operation and investment decisionmaking. The Commission recognizes that designing sophisticated PBR mechanisms will be a significant challenge for RTOs already grappling with other development issues. The Commission, therefore, will make its staff available through our pre-filing process to work with RTOs to help identify and resolve issues on an informal basis prior to their filing a PBR proposal.[644]

7. Other RTO Transmission Ratemaking Reforms

The Commission proposed in the NOPR to consider innovative pricing proposals for transmission owners who turn over control of their transmission facilities to an RTO.[645] The types of pricing that the Commission proposed to consider include: a higher ROE on transmission plant; allowing the transmission owner to retain the benefits of cost saving attributable to RTO formation; acceleration of transmission cost recovery in rates; non-traditional valuation of transmission assets such as an estimate of replacement costs for assets purchased at higher than net original cost; and liberalized allowance of levelized or non-levelized rate methods. The Commission proposed that transmission owners meet all of the requirements to become an RTO before an innovative pricing proposal is accepted.[646]

Comments. A large number of commenters addressed the Commission's proposals to consider transmission pricing reforms for RTOs. About 30 commenters expressed support, and about 30 commenters expressed opposition. There were also a number of comments which did not explicitly support or oppose this aspect of the NOPR.

Supporting Innovative Pricing.[647] Of the commenters that support innovative pricing, a common theme is that if RTO formation is to be voluntary, incentives are required to encourage participation.[648] For example, Justice Department recommends that the positive and negative incentives be designed to secure universal compliance rather than have some utilities not participate because the advantage of continuing outside of the RTO is greater than the incentive to join. EEI supports incentives since RTO formation will probably not generate increased earnings for transmission owners since most of the efficiencies will be a benefit to others. EEI suggests that an application for RTO formation and incentives should include some assessment of the benefits from which the incentives are generated but a precise calculation of benefits should not be required because of the extreme difficulty in making such an estimate. PacifiCorp is in favor of incentives but is concerned that a ''case by case'' consideration of incentives may jeopardize their realization because customers will call for lower transmission rates in the short term once the RTO has been formed. PacifiCorp argues that a more detailed uniform policy on incentives ''up front'' is preferred.

On the other hand, several commenters suggest that the Commission should consider incentives only on a case-by-case basis. Desert STAR says that different RTOs may need different sets of incentives as will public power transmission owners. MidAmerican supports case-by-case consideration of incentives to join an RTO, and favors a higher ROE reflecting the fact that transmission is not limited to selling to a captive customer base in a bundled context but is serving a wholesale marketplace at greater risk. Duke is in favor of incentives for transmission expansion, but cautions that incentives should not bias investment and other decisions, should be considered on a case-by-case basis, and may not be very effective where operation is separated from ownership. Oregon Office is in favor of incentives for meeting all of the RTO characteristics and functions faster than the industry average, but not for average speed in accomplishing RTO formation.

A number of commenters favor offering incentives to public utilities that are already members of an ISO as well as to provide incentives for public utilities to join an RTO. For example, PJM says that incentive rates should be offered to new and existing RTO members to reflect the benefits generated and to prevent inefficient consequences such as transmission owners moving from an existing ISO to a new RTO to receive incentive rates. PSE&G favors a correspondingly higher ROE and faster depreciation of transmission assets for transmission owners who participate in RTOs, including those who have already joined an existing organization. LG&E says that incentive plans can be useful in promoting RTO participation and that existing members of RTOs should be allowed to propose incentive rates as well. LG&E stresses that it is just as important not to enact policies on rates that might jeopardize revenue requirement recovery and thus act as a disincentive. An additional consideration is offered by PP&L Companies which argues that existing participants in RTOs should be allowed the same incentive rates as those which are just forming because the benefits of an existing RTO are greater than those of a start-up RTO not yet in operation.

The proposed incentive addressed most frequently by commenters is allowing a higher rate of return on transmission assets. Georgia Transmission believes that higher ROEs as an incentive to voluntarily join an RTO is appropriate because of the benefits that participation would bring. NSP and others argue that ROE must be sufficient to attract capital and compensate utilities for the risks involved. Conectiv and EEI argue that the current rate of return policy should be modified, arguing that the DCF method gives results that are too low to provide adequate returns to transmission owners causing a reduction in building at a time when more transmission is critically needed. According to Conectiv, the DCF method should be abandoned or its application

[644] Alternatively, the RTO could seek guidance in a more formal proceeding, *e.g.,* if an RTO files a petition for a declaratory order seeking approval of its PBR proposal.

[645] FERC Stats. and Regs. ¶ 32,541 at 33,755.

[646] *Id.* at 33,756.

[647] While we used the term incentive pricing in the NOPR, this term is an imprecise description of the various transmission pricing reforms that will be addressed in this Rule, and we now describe these pricing reforms as innovative rate proposals. However, the comments sections that follow continue to use the term incentive because the parties used this term in their comments.

[648] *See, e.g.,* Avista, TEP, Duquesne, APS, NEPCO *et al.,* Florida Power Corp.

should be modified to account for the current industry situation and be more reflective of conditions in the general economy and reflect reasonable transmission asset lives. Cinergy, in reply comments contends that the record in this proceeding is sufficient to establish a presumption of reasonableness for higher ROEs.

SoCal Edison does not believe that pure incentives in the form of ROE ''awards'' are necessary for encouraging participation in RTO but it does argue that higher returns may be justified on transmission assets controlled by an RTO because the original owner no longer has control over planning and expansion decisions. In addition, distributed generation and bypass may be found to increase risk. SoCal Edison says that it is very important to prevent the move to RTO control from being a financial loss due to Commission rate setting or because of greater risk and higher costs. SoCal Edison does agree with the proposal to allow accelerated depreciation of transmission assets to encourage participation.

TXU Electric is in favor of consideration of higher ROEs for RTO participants and thinks it is more important to take a more global look at transmission ROEs in a new and uncertain industry environment where transmission investment is important. TXU Electric warns that it would be inappropriate to penalize RTO participation with reduced earning potential because unbundled transmission ROEs are lower than ROEs allowed in bundled rates. Conlon suggests that the Commission could allow a higher return on assets of a transco or ISO to serve as an incentive for IOUs to transfer ownership. Southern Company explains that there are major tax consequences to the sale of transmission assets to form a transco and recommends that the Commission find ways to accommodate such a transition. As to rate incentives, Southern Company advocates a change in the Commission's ratemaking policy in order to increase returns to be more commensurate with non-regulated businesses. Southern claims that recent court rulings support higher returns on transmission service.

A number of commenters argue that participation in an RTO increases financial risk, and that incentives are therefore required to encourage RTO participation. For example, Empire District says that turning over control of transmission assets to an RTO increases the risk because someone else will control their operation, justifying higher ROEs for participation. PSE&G argues that a stand-alone transmission company or an RTO is more risky than an integrated electric utility where transmission was a strategic asset. FirstEnergy justifies higher ROEs by noting a number of sources of risk, including emergence of distributed generation, vulnerability of firms that are less diversified than integrated utilities, and quicker phase out of older generation plants which may result in stranding some transmission plants. Midwest ISO argues that RTO membership may cause a loss in earnings due to reduced transmission revenues, higher costs, and operational risks. United Illuminating believes that risk for transmission investment is higher for assets controlled by an RTO and that accelerated depreciation is warranted because transmission companies can no longer count on captive customers, and industry changes have the possibility to abandon transmission plant before its physical life is over. WPSC is in favor of higher ROEs for transmission owners who join RTOs but not as a pure incentive. WPSC's justification for higher ROEs would be the greater risk due to removal of pancaked rates, new generation options, loss of higher state returns, and new technologies. WPSC supports the other rate incentives as long as the benefits exceed the costs based on careful examination.

Some commenters address the broad range of proposed incentives. For example:

- Trans-Elect argues in favor of incentives to include: acquisition premiums, hypothetical capital structures, higher ROE, accelerated recovery of costs, rate moratoriums, and expedited FPA section 205 and 203 approvals. Trans-Elect would limit incentives to those that do not harm transmission customers. It notes that PBRs would allow transmission owners to share in cost savings but some operating history may be needed before they are put in place. It argues that acquisition premiums may assist in the formation of independent transcos, and suggests that if there is a rate moratorium in place, RTOs should be allowed to recover acquisition premiums after the moratorium.
- FirstEnergy advocates flow through of cost savings to owners, non-traditional valuation of assets, flexibility in the use of levelized rate methodology, retention of hourly non-firm revenues, deference to management in dispute resolution, elimination of codes of conduct where there is structural separation, and simplification of filing requirements. Some of these measures should be offered on a limited basis to RTOs not yet meeting all of the characteristics and functions. Incentive plans should weigh costs versus benefits. Cal DWR goes further, saying that incentives should not be allowed until benefits are actually proven.
- Los Angeles recommends that the Commission consider several options for the valuation of assets transferred to an RTO in order to reflect the true value of the assets to native load customers. Selected options to explore include: an up-front acquisition premium used to moderate rates to native load customers, provide native load customers a congestion premium, or grant native load customers an exemption to congestion charges.
- NYPP is in favor of sufficient ROE to provide for expansion and accelerated depreciation to compensate for increased risks as opposed to a ''bonus'' type incentive to join an RTO. Its members contend that this type of incentive should be available to all transmission owners, not just the ones who meet the NOPR's characteristics and functions.

A number of commenters note that incentives are needed to facilitate efficient expansion of transmission assets.[649] Transmission ISO Participants view the incentive needed to induce new transmission construction as more important than incentives to encourage RTO formation. IPCF suggests that FERC should offer transmission owners incentives to expand their networks without meeting all of the requirements of becoming an RTO in order to reverse the trend against building caused by Order No. 888. Williams says that decisions to expand transmission facilities must be made by for-profit entities, must be driven by economic considerations, and the returns allowed must be commensurate with the greater risks today, Williams cautions that returns for RTO participants certainly should not be at a rate that results in a penalty.

Opposing Innovative Pricing. Many commenters oppose the use of incentives for many different reasons. One common theme is that incentives are inappropriate because RTO participation should be mandatory.[650] PJM/NEPOOL Customers argues that the Commission should mandate RTO formation because of the transmission owners' duty to operate in an efficient manner, and because transmission customers will likely pay the costs of the incentives. Ohio Commission

[649] *See, e.g.,* AEP, United Illuminating, PP&L Companies, NU, Otter Tail, NYPP, FirstEnergy, Transmission ISO Participants, Allegheny and Salomon Smith Barney.

[650] PJM/NEPOOL Customers, Lincoln, TDU Systems, APPA, WEPCO.

prefers mandatory participation and questions whether the proposed incentives will be effective. If incentives are used, Ohio Commission recommends that the Commission consider evaluating which incentives will be effective, balancing incentives with disincentives, and recognize regional differences especially in arriving at a solution for the Midwest.

Another common theme is that the costs of incentives may well outweigh the benefits of RTO participation. Illinois Commission argues that if the Commission finds that there are benefits in RTO creation, they should be mandatory. According to Illinois Commission, the examples of incentives proposed in the NOPR, *i.e.*, ROE enhancement, revaluation of transmission facilities at replacement cost, accelerated depreciation, and flexibility in use of levelized cost, would consist of money transfers to transmission owners without contributing to cost control or efficiency. South Carolina Authority is opposed to incentives or disincentives to promote RTO participation unless a factual determination is made that they are absolutely necessary. Similarly, RECA is generally opposed to incentives but would recommend their consideration if savings to the public are well established. RECA finds the rate freeze proposal the least objectionable.

APPA advocates mandatory participation in RTOs and strongly objects to the use of incentives to achieve participation. It argues incentives would be ineffective because of the small proportion that Commission-regulated transmission makes up of the total utility revenue compared to the value of transmission in maximizing generation and merchant revenue. To be effective, APPA argues that the cost would be so large that it would not be offset by the benefits of the RTO. Also, APPA raises the participation issue of whether to give incentives to existing ISO members. Seattle warns against transmission owners "dumping" transmission facilities into an RTO to receive incentives when those particular facilities are of no benefit to the RTO being formed.

Some commenters argue that it is inappropriate for the Commission to provide incentives for the provision of a monopoly service. Metropolitan argues that incentives should not be offered because many of the customers who pay for the incentives are the same customers who paid for the original transmission facilities. TDU Systems argues that ROEs for transmission service in an RTO is less risky because of the concentration of monopoly business and the lack of any regulatory gap since all transmission under an RTO will be regulated by the Commission. TDU Systems notes that transmission entities, since they are monopolies, should not earn the same return as firms in other industries. TDU Systems argues that other NOPR proposals, including rate freezes, accelerated recovery of costs and investment, and revaluation of assets, are also an inappropriate enrichment of transmission owners and are unneeded to attract investors. And TDU Systems argues that the proposal for an acquisition premium is troublesome because customers have already been paying for these assets for years. TDU Systems also suggests it will be difficult to calculate what level of incentives would be required to persuade a transmission owner to participate in an RTO and the likelihood of offering a greater incentive than is needed.

Some commenters suggest that providing incentives would violate the Commission's statutory requirement to set rates at just and reasonable levels. NRECA believes that transmission owners should not be rewarded for unjust conduct with incentives and that the Commission should rely on standard cost-of-service based rates. TAPS, which favors mandatory RTO formation, argues that incentives are unnecessary and could nullify the benefits of electric industry restructuring. TAPS argues that incentive rates, including each of the examples suggested in the NOPR, would violate FPA's requirement for just and reasonable rates because they do not reflect the cost of providing transmission service. TAPS does recommend that the Commission remedy unintended disincentives such as utilities' fear of the unknown. UAMPS also favors mandatory participation, and argues that incentives would unfairly raise transmission costs to the benefit of monopoly transmission owners. UAMPS also argues that it is not feasible to divide the benefit of RTO participation before these benefits are even known. In response to the comments of several IOUs, UAMPS argues that the claim that stand-alone transmission companies are more risky is unsubstantiated and should be heard in another proceeding. NASUCA argues that EEI and others are incorrect in saying that the DCF method does not produce reasonable results. According to NASUCA, the DCF method takes explicit account of the transmission owners' risk and the realities of the current regulatory climate.

Some commenters suggest that incentives will not necessarily increase RTO participation, or will not necessarily produce the benefits which the NOPR describes. For example, ICUA notes that incentives cannot be relied upon to achieve participation by all necessary utilities. WPPI opposes incentives to participate in RTOs citing the RTO activity that has already taken place without incentives and the contention that the Commission should designate boundaries and require participation within one year.

Wyoming Commission does not agree that increasing the ROE will be sufficient to encourage more transmission building. According to Wyoming Commission, low building activity may be attributable to difficulty in meeting siting requirements, uncertainty related to retail access and native load, and competition for more localized generation. Wyoming Commission does not think that the Commission should rush too quickly into some innovative ratemaking before the industry has committed to making RTOs work as planned. And the Wyoming Commission suggests that a higher ROE for transmission investment may discourage a balanced consideration of options.

A number of commenters generally opposed incentives, believing that sanctions or penalties against public utilities which do not join RTOs is superior to providing incentives. NASUCA argues that mandates or disincentives for not joining at the time of merger or market-based rate requests should be used rather than incentives. Incentives would not be cost based and would therefore make rates unjust and unreasonable. As to specific incentive proposals, NASUCA says that using replacement cost for transferred assets would allow higher rates than necessary as an incentive and would charge customers for assets they have already paid for. Such incentives could set off a transmission sell-off in anticipation of an adjustment and some companies may refuse to form transcos until they were granted the same adjustment as any other company. NASUCA is opposed to accelerated depreciation of assets for similar reasons. NASUCA also states that incentive rates could harm electric competition by increasing transmission costs. And Big Rivers states that the incentives proposed in the NOPR are inappropriate for rural electric cooperatives.

Other Comments. A few commenters did not take an explicit position on the use of incentives, but made general comments on the Commission's proposals. For example:

• Cal ISO is more concerned that there not be disincentives to RTO participation than offering incentives. In particular, Cal ISO points out the disincentive created by the Commission's annual fee policy, from which temporary relief was granted [651] but a permanent solution is needed.

• New Century recommends against the use of ''remedial measures'' to encourage participation such as the suspension of market-based rate authority, denial of merger authority, and denial of non-pancaked rate access to RTO facilities.

• Entergy says that the NOPR's statements on incentives are vague and would cause too much regulatory uncertainty. Entergy asks the Commission to provide more explicit provisions as to what incentives would be approved.

• Canada DNR is concerned that Canadian transmission owners not be placed at a disadvantage for non-participation in an RTO in terms of incentives and disincentive.

• SRP supports incentives as long as they are applied to both public power entities and investor owned companies equitably.

• Metropolitan contends that it would not receive much benefit from any incentives offered to RTOs because it is a public entity and because its asset base is so heavily depreciated. However, replacement cost methodology could be of use in mitigating cost shifts from rolling in higher costs of other utilities.

Commission Conclusion. As noted earlier, the NOPR and the comments use the term incentive pricing as a label for the transmission pricing reforms that we raised for discussion. Certainly, good pricing affects behavior. But good pricing also achieves a valuable goal, in terms of competition, system expansion, or efficient practices that benefit more than the transmission owners or the RTO. In this section we provide greater specificity with respect to certain transmission pricing mechanisms that may be appropriate for RTOs. These mechanisms were described in the NOPR or otherwise proposed by commenters, and are included in the amended regulatory text.[652] We emphasize that we do not intend this policy guidance to be interpreted as a Commission regulatory requirement for a specific transmission pricing method, nor should it be interpreted as a guarantee that the Commission will approve any particular innovative pricing proposal. We emphasize that all innovative pricing proposals filed by RTOs must be fully and adequately supported in accordance with this Final Rule and the regulatory text. We believe that we are providing sufficient guidance for RTOs to make critical decisions with respect to transmission pricing policies. If industry participants believe that further guidance from the Commission is needed to resolve transmission pricing issues, they may request such guidance through requests for declaratory orders or further rulemakings.

As discussed earlier, transmission pricing reform is needed as a result of the rapid restructuring of the industry that is underway, particularly with respect to changes in the ownership and control of transmission assets, and changes in the transmission services being provided in competitive generating markets. As a result of these changes, and consistent with a number of commenters' arguments, we have concluded that the Commission, at a minimum, needs to mitigate various ''disincentives'' that may prevent transmission owners from efficiently operating their systems. Commenters cite to the potential that transmission owners will earn lower returns for providing unbundled transmission service than they earned for providing bundled service, even though risks associated with transmission ownership have increased. Commenters suggest a number of sources of increased risk. One source is the potential for bypass of transmission assets due to distributed generation and the phasing out of older generators from service. Other sources are directly related to RTO formation. For example, some commenters assert that stand-alone transmission companies (*e.g.*, transcos) are riskier because they have a less-diversified portfolio of assets than a vertically integrated utility. Other commenters argue that participation in an RTO that is an ISO is inherently riskier, suggesting that increased risk comes from ownership of transmission assets that are ceded for purposes of operational control to another, non-affiliated entity.

Other commenters argue that a reevaluation of transmission pricing is needed because it is absolutely critical that the transmission grid support competitive generating markets, and the only way that the Commission can ensure this will happen is to pursue pricing policies that encourage it. Some commenters suggest that because the contribution of transmission to total costs of energy is relatively small[653] overinvestment in transmission will not significantly affect delivered electricity prices. Further, the Commission should be much more concerned about underinvestment, not overinvestment, in the transmission grid.[654] Stated another way, an efficient transmission grid is a prerequisite to achieving competitive generating markets, and the potential benefits for consumers far exceed any limited overinvestment that may occur on transmission service. A related argument is that efficiency benefits of improved transmission service will be captured by producers and customers of generation, not transmission providers; therefore, greater incentives for RTOs to provide good transmission operations and efficient investments in the grid are warranted.

The NOPR sought comments on several procedural issues related to transmission pricing reform and incentives. One issue was whether these pricing reforms should be available to participants of existing ISOs, or be available only to transmission owners that join RTOs as a result of the Commission's RTO initiative. We have concluded that members of an existing ISO organization that satisfy the minimum RTO requirements in the regulatory text should be allowed to seek transmission pricing reform as newly formed RTOs, so that they can avail themselves of the same incentives for efficient operation of and investment in the transmission grid. Furthermore, we believe that the Commission's approach to evaluating innovative transmission reforms should be neutral with respect to the organizational structure of the Applicant, so that RTOs that own transmission assets as well as RTOs that do not own transmission assets would be equally eligible for such ratemaking treatments.

Another issue is whether the Commission would prescribe which transmission pricing reforms it would accept and which it would not accept, or whether the Commission would consider such proposals on a case-by-case basis. We conclude that a case-by-case evaluation of transmission pricing

[651] PJM Interconnection L.L.C., 88 FERC ¶61,109 (1999).

[652] Note that these mechanisms are discussed below on a thematic basis, although the regulatory text lists them on an individual basis.

[653] For example, Salomon Smith Barney, citing to an article by Leonard Hyman notes that the direct, total osts of transmission service represents about six to seven percent of the average customer's bill, and raising transmission prices even as high as 25 percent in order to attract capital adds only two percent to the overall electric bill.

[254] Professor Joskow points out that the external factors, such as licensing requirements, the need for rights of way, and NIMBY (*i.e.*, ''not in my backyard'') opposition to transmission expansion already places significant constraints on overinvestment in major new transmission projects.

reform proposals is appropriate, given that such proposals are not generic in nature, and a proposal may be appropriate in some RTO circumstances but not in others. However, the Commission believes some further specificity on transmission pricing reform is warranted to provide industry participants with the Commission's evolving views, as RTOs consider the appropriateness of various reform measures.

Therefore, we provide greater specificity on three transmission pricing reform measures: (1) ROE; (2) levelized rates; and (3) accelerated depreciation and incremental pricing for new transmission investments. We note that some of these measures may be useful only as transitional devices that may be necessary to spur the prompt creation of RTOs and, therefore, we intend to offer these pricing options only for a defined period of time, as detailed later in this Final Rule. On the other hand, other pricing reforms may be useful as permanent features, and will not be limited only to the period during which RTOs are forming. Finally, while certain of these innovative pricing proposals may be more helpful to one RTO structure than another (*e.g.*, ISO vs transco), we do not believe that any of these pricing proposals would be incompatible with any particular structure adopted by RTOs.

a. Return on Equity (ROE). More commenters focused on ROE-based proposals than any other type of transmission pricing reform. These commenters make two main points. One argument is that higher ROEs will be demanded by the market as a matter of course as the industry restructures and the risk of transmission business increases, and the Commission must allow higher ROE to reflect participation in RTOs. A second argument is that joining an RTO adds another level of risk that warrants a specific adjustment to ROE (*e.g.*, going to the high end in the range of reasonable ROE, or a specific basis point adjustment).[655]

As discussed above, commenters urge the Commission to provide flexibility in allowing ROE-based programs for RTOs. Many of these commenters specifically urge the Commission to ensure that there are sufficient incentives for an RTO to make needed investments in transmission infrastructure. On the other hand, a number of commenters oppose ROE-based programs on the grounds that they constitute a ''bribe'' for utilities to provide service that they are statutorily required to provide.

We believe that there are a number of issues surrounding ROE that must be addressed by the Commission. For example, we believe that allowing an RTO to propose a formula rate for determining return on equity is consistent with our view that risks and rewards for transmission owners should reflect market-like forces to the extent possible. Allowing a formula rate of return would decouple a transmission owner's earnings from its own equity valuation, and would tie it more to external standards such as industry-wide performance. Such an approach is also consistent with the benchmarking that may occur under PBR.

We also agree that the risk profile of the transmission business is changing as the industry restructures, and that it may vary as a function of the structure each transmission company elects. For example, the risk associated with owning facilities that are leased for a sum certain to another entity operating an RTO may be different from the risk associated with operating a stand-alone transco that is facing a significant expansion program. We therefore conclude that ROE-based initiatives—as well as other ratemaking reforms discussed below—may be applicable to all types of RTOs, without regard to organizational structure.

We further recognize that historical data typically used to evaluate ROEs may not be reliable since it reflects a different industry structure from the one that exists recently. And we believe that as patterns of transmission ownership and control evolve, new approaches to compensating transmission owners for different capital structure mixes may be warranted, including allowing a transmission owner to seek a return on invested capital, independent of its exact capital mix.[656] As noted above, we are willing to consider moratoriums tied to the rates the transmission provider earns on transmission assets with respect to bundled retail power sales, and the moratorium option may be tied to the existing transmission rate level, or to the existing return on equity.[657]

Finally, we agree that the uncertainty associated with the transition of the industry, and in particular participation in RTOs, may increase risks in the short-run. Certainly, our goals have not changed, which are to ensure that customers have access to nondiscriminatory service at just and reasonable rates, and that transmission owners have an opportunity to earn a reasonable rate of return on their investment. We recognize that in this era of rapid change, new approaches to setting ROE may be needed to implement that standard. We therefore invite RTOs to submit proposals for ROE-based programs that are in conformance with these new approaches.

We note that pricing reforms involving ROE would clearly be compatible with all types of RTO structures that involve a determination of return on equity on transmission rate base, *e.g.*, transcos, ISOs, or tiered organizational structures.

b. Levelized Rates. A number of commenters argue that the Commission should allow RTOs to adopt levelized rates. A levelized rate is designed to recover all capital costs through a uniform, nonvarying payment over the life of the asset, just as a traditional home mortgage payment does. The Commission, has held in a number of recent proceedings that both levelized and nonlevelized rates can produce reasonable results, depending on the circumstances.[658] The Commission stated in these cases that where a utility proposes to switch from a nonlevelized net plant rate design method, ''[i]n supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method.'' [659]

The Commission believes that levelized rates are preferable in an RTO environment because all customers, regardless of when they take service, face the same price. Also, given a depreciated investment base, levelized rates based on existing investments will be higher than non-levelized rates and will address concerns that RTO formation will decrease revenues.

The principal objection to allowing levelized rates for RTOs is that it may raise RTO transmission rates in the short-run. The Commission has been reluctant outside the RTO context to approve switches from or to levelized rates proposed by public utilities under traditional cost-of-service ratemaking because of the opportunities that switching may provide for utilities to

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[655] Some commenters recommend abandoning the DCF method of calculating ROE entirely. We are not adopting that recommendation.

[656] As noted *infra*, this is one of the pricing reforms that will be available only for a defined transition period during which RTOs are being established.

[657] As noted *infra*, moratoriums are among the pricing reforms that will be available for a defined transition period during which TROs are being established.

[658] *See, e.g.,* American Electric Power Service Corp., Opinion 440, 88 FERC ¶ 61,141 at 61,441–42 (1999) (*AEP*); Allegheny Power Service Corp., Opinion 433, 85 FERC ¶ 61,275 at 62,117 (1998); Kentucky Utilities Co., Opinion 432, 85 FERC ¶ 61,274 at 62,100–03 (1998) (*KU*).

[659] *See AEP,* 88 FERC at 61,441–42.

over recover transmission costs. However, consistent with our discussion above of how market restructuring may require innovation in transmission pricing, we believe that levelized rates may be appropriate in circumstances, as here, where an RTO reflects a fresh start with respect to the provision of transmission services, and potentially the customers for those services. This is especially true in cases where RTO formation occurs coincident with market restructuring, such that the transmission customers of the RTO may be significantly different than the traditional, captive customers, that formerly took transmission service. We therefore conclude that the Commission should allow increased flexibility for RTO proposals that include ratemaking practices based on levelized rates. Clearly, this pricing reform, which relates to the method used to compute the transmission revenue requirement in the first instance, is compatible with any type of RTO structure, e.g., transco, ISO, or tiered structure.

c. Accelerated Depreciation and Incremental Pricing for New Transmission Investments. While a number of commenters have suggested accelerated depreciation as a transmission pricing reform that should be considered, these arguments are premised on the possibility that transmission costs will be stranded by changes in the industry, such as bypass of portions of the transmission system. We think that these concerns are speculative at this point in the industry's restructuring. For example, we are not convinced that the problem of stranded transmission assets is anywhere near the level of concern that stranded generating assets represents.[660] In any event, should certain limited transmission facilities become stranded, nothing prevents proposals to recover prudent costs under traditional ratemaking policies.

We will, however, make a distinction between accelerated depreciation for existing transmission assets, and accelerated depreciation for new transmission facilities. While we will not bar proposals of this type for existing assets, we cannot give any encouragement to them in the Final Rule. On the other hand, we believe that it is appropriate for the Commission to provide those willing to make new transmission investments with the flexibility to propose that such assets follow non-traditional depreciation schedules. The purpose of providing such flexibility is to remove disincentives for the construction of new facilities. We think such flexibility is warranted because the fundamental nature of transmission investment may be changing with respect to the entities that will make investments in the transmission system in the future and who pays for the new transmission facilities. Furthermore, given the rapid changes in market structure and dynamics that have occurred and will likely continue, we are not certain that traditional determinations of the economic life of new transmission facilities remain appropriate.

In addition, we believe it is appropriate for the Commission to provide flexibility for pricing of new facilities, such that proposals for pricing of new facilities that combine elements of incremental prices with embedded-cost access fees will be considered. Although we are concerned that such ratemaking practices have the potential to lead to higher prices for new transmission services, and also potential to lead to overinvestment in transmission facilities, e.g., where generation redispatch could accomplish the same objective at lower cost, we believe that such practices, if carefully constructed, will create appropriate incentives for efficient investment in new transmission facilities. We also believe that this pricing reform will be attractive to all types of RTO structure, e.g., transcos, ISOs, or tiered structures. It may also be used by any RTO that chooses to rely on third parties to construct new facilities.

d. Acquisition Adjustments. A number of commenters suggest that the Commission adopt new policies for acquisition adjustments that would provide assurances to purchasers of transmission facilities that acquisition premiums would be recoverable through transmission rates. We do not adopt this suggestion in this Final Rule.[661]

8. Additional Ratemaking Issues

A number of comments on ratemaking issues address topics not specifically enumerated in the NOPR.

Comments

• Williams, CSU, Alliance Companies and WPSC encourage the Commission to consider rate designs based on mileage or network usage.

• Great River, NCPA and IMPA raise the concern that cooperatives and public power entities need assurance that they will receive full customer credit and compensation as was explicitly stated in Order No. 888. SoCal Edison claims that full compensation will be forthcoming and will not be a problem.

• Ohio Commission recommends that a tariff for border transactions (between RTOs) be implemented that makes the market over the combined regions seamless to persuade some regional organizations to combine.

• PPC notes that IndeGO ran into a problem with developing rates for combined systems with very different levels of quality and cost, and that systems at a position of lower quality should be required to meet combined system standards at their own cost.

• Puget argues that RTO rates must provide for the collection of stranded costs.

• PSNM sees a problem with load-side generation customers who do not have to pay their fair share of total system transmission costs.

• Powerex objects to the proposal to segment companies' service areas into sub-zones for pricing purposes.

• Alliance Companies and AEP favor the flexibility in RTO rate filings that would allow companies to make proposals that reflect market forces.

• Alliant Energy is concerned that RTO structures promote workable markets and that transmission rates be permitted to include a fair accounting of RTO start-up costs.

• East Texas Cooperatives recommends that RTO pricing structures adequately compensate small transmission owners who join the RTO, creating an incentive to join and be a more equitable system.

• Georgia Transmission says that ratemaking for RUS borrowers must take into account the requirements of any RUS loans. In addition, Georgia Transmission recommends that the cost of RTO formation be allowed in RTO rates.

• Metropolitan, Cal DWR, and SoCal Cities favor the use of time-of-use pricing or off-peak rates for transmission.

• Oregon Office recommends load-based fees for transmission rather than volume based charges.

• IMEA argues that the RTO start-up and administrative costs should be

[660] *See* Order No. 888, wherein the Commission allows recovery of stranded costs (primarily generation related) only when they are unrecoverable from customers that depart the system, and only upon a definitive showing that the utility had a reasonable expectation of continuing to serve the customer after the customer's departure.

[661] *See* Minnesota Power & Light Company and Northern States Power Company, 43 FERC ¶ 61,104 at 61,342 (1988), for a discussion of the Commission's existing policies with respect to the ratemaking treatment for acquisition premiums. *See also* Duke Energy Moss Landing LLC, *et al.* 83 FERC ¶ 61,318 (1998).

allocated to all customers including bundled native retail load. In contrast, LG&E notes that if native load is assigned RTO administrative costs there may be under recovery because of retail rate freezes.

- Industrial Customers argue that assets used for remote generation should be excluded from the RTO.
- Merrill Energy says that the incremental pricing of new transmission upgrades prevents expansion because customers are unwilling to pay.
- NERC is concerned about the recovery of costs related to reliability-related generators.
- NRECA is concerned about compensation by an RTO for low-use transmission facilities owned by cooperatives, because large transmission owners are opposed to revenue sharing. NRECA notes that if a cooperative joins an RTO, transactions for all will increase and there is more to share. Also, there should be protection for joint use agreement income.
- Project Groups says that pricing must facilitate entry and usage by efficient, environmentally benign resources. Grid access barriers to these resources need to be eliminated. NMA/WFA/CEED respond by saying that the policies that Project Group objects to are equitable overall.
- Seattle argues that hub and spoke pricing should be used and discrete inter-regional tariffs are needed.
- NWCC notes that the characteristics of wind-produced power presents problems fitting into an RTO pricing arrangement and says that wind power works best with energy-based pricing systems.
- Detroit Edison advocates a two-part pricing structure similar to that proposed by the Alliance RTO. It includes a local rate and a regional rate. To encourage participation, Detroit Edison proposes that the Commission allow RTOs to develop market-based transmission pricing methodologies.

Commission Conclusion. Commenters raise a number of important ratemaking issues that must be considered in the establishment of RTOs. We clarify that the reasonable costs of developing an RTO may be included in transmission rates. Other issues are at a level of detail and specificity that we do not believe should be resolved in this Final Rule. Therefore, these issues will be considered as they apply to individual RTO proposals on a case-by-case basis.

9. Filing Procedures for Innovative Rate Proposals

We shall evaluate all RTO proposals including any innovative rate treatment based on the applicant's demonstration of how the proposed rate treatment would help achieve the goals of regional transmission organizations, including efficient use of and investment in the transmission system and reliability benefits. We shall also require applicants to provide a cost-benefit analysis, including rate impacts, and demonstrate that the proposed rate treatment is appropriate for the proposed RTO and that the rate proposal is just, reasonable, and not unduly discriminatory.

In addition, pricing proposals involving moratoriums and returns on equity that do not vary according to capital structure may not be included in RTO rates after January 1, 2005. Thus, if the Commission approves an RTO rate proposal involving, *e.g.,* a rate moratorium, unless otherwise ordered, the moratorium would end on or before January 1, 2005. We are limiting these rate proposals for a defined period during the formative stage of RTOs because, while either may be appropriate as transitional rate mechanisms, they do not promote long-term efficiency through rate design. In addition, the limited duration for these rate treatments will encourage the earliest possible filings, while at the same time giving some flexibility to those filings that may be delayed.

H. Other Issues

1. Public Power and Cooperative Participation in RTOs

In the NOPR, the Commission stated its objective of encouraging all transmission owning entities including transmission owned or controlled by public power entities and cooperatives, including Federal Power Marketing Agencies (PMAs), Tennessee Valley Authority (TVA), and other state and local entities to place their transmission facilities under the control of an RTO.[662] To this end, we expressed an expectation that public power entities would fully participate in the collaborative process for forming RTOs.[663] In addition, we noted that some public power entities filed open access tariffs with the Commission and others are participating in ISOs and other regional institutions. The Commission, however, is aware and concerned that public power entities face several difficult issues regarding RTO formation and participation.[664]

The first issue is the Internal Revenue Service (IRS) Code ''private use'' restrictions on the transmission facilities of public power entities financed by tax-exempt bonds. We noted that IRS temporary regulations may allow facilities financed by outstanding tax-exempt bonds to be used to wheel power in accordance with Order No. 888, but that these temporary regulations may not allow the issuance of additional tax-exempt bonds for expanded transmission or permit transfer of operational control of existing transmission facilities financed by tax-exempt bonds to a for-profit transco.[665] The Commission asked for comments on the extent to which IRS Code restrictions may limit the transfer of operational control or other forms of control, or ownership of public power transmission facilities to a for-profit transco or other forms of an RTO.

The Commission also requested comments on state and local charter limitations, prohibitions on participating in stock-owning entities, the current policies of various local regulatory entities that affect or impede full public power participation in RTOs and legal restrictions or other considerations regarding PMAs that prevent their participation in RTOs. We questioned whether the Commission should consider some forms of associate membership or participation and other special accommodations in order for public power entities to overcome obstacles to RTO participation.[666]

Comments. Most commenters support the Commission's position that a properly formed RTO should include all transmission owners, including cooperatives and public power, in a specific region.[667] As EEI notes, public power participation will enhance the reliability and economic benefits of an RTO. Furthermore, some commenters argue that in some areas of the country, especially in the Northwest and Southeast, RTO formation may be impractical without public power participation.[668] Virtually all commenters recognize that regulatory and legal restrictions exist that may impede public power and cooperative participation in RTOs. EEI, SERC and Metropolitan argue that the best way to

[662] FERC Stats. and Regs. ¶ 32,541 at 33,756–57.

[663] *Id.* at 33,757.

[664] *See id.*

[665] *Id.*

[666] *See id.*

[667] *See, e.g.,* Oglethorpe, Allegheny, Montana Power, CREDA, Tallahassee, Arkansas Cities, PPC, California Board, Industrial Customers, Entergy, BC Hyrdo, Powerex, Aluminum Companies, MEAG, Arizona Commission, Nevada Commission, East Texas Cooperatives, Lincoln, NPPD, Wyoming Commission, Georgia Transmission, WPSC, PGE, Montana Commission, SMUD, Cal ISO, MLGW, Loveland Customers, NASUCA, Duke, LG&E, CP&L, South Carolina Authority, STDUG, NCPA, PP&L Companies, Desert STAR, PG&E and EEI.

[668] *See, e.g.,* EEI, Snohomish, MLGW, Loveland Customers, Montana Commission, Wyoming Commission, Aluminum Companies, Industrial Customers and Powerex.

facilitate non-jurisdictional utility participation in RTOs is for the Commission to avoid a ''one-size-fits-all approach'' and to provide flexible rules in order to accommodate the unique needs of public power entities.

Section 141 of the IRS code imposes limitations on the use of non-governmental entities of public power facilities financed with tax exempt bonds. These private use limitations restrain the form and extent of participation by public power systems in RTOs. The key private use limitation that is material to RTO participation is a bar on the sale of the output of facilities financed with tax exempt debt to non-governmental entities on terms not available to the general public. Commenters note that in January 1998, the IRS issued temporary regulations relating to the application of the private use rules to public power entities that provide some relief for transmission facilities. These temporary regulations permit issuers of outstanding tax exempt bonds to offer open access transmission services and competitive access to distribution systems, and to join RTOs, provided that certain conditions are met, particularly that the facilities continue to be owned by the municipal entity. The temporary regulations, however, do not provide the same relief to issuers of new tax exempt bonds. Many commenters assert that the temporary regulations will expire in January 2001 and that these regulations are incomplete and not permanent.[669] LPPC notes that the ability of issuers to continue to rely on the temporary regulations after expiration is unclear and therefore, issuers taking actions permitted under the temporary regulations risk having tainted the tax-exempt status of their bonds on the expiration of the regulations.

Commenters offer varying solutions to the ''private use'' restriction problem. Many commenters urge the Commission to actively attempt to influence the IRS and Congress to remove and/or mitigate the tax impediment.[670] SRP also recommends that the Commission require all RTOs to demonstrate that they have made a good faith effort to reduce barriers to participation and to accommodate legal restrictions faced by potential participants. Arkansas Cities proposes a transitional grandfathering of existing tax-exempt bonds. Arkansas Cities notes that such legislation is pending in Congress and is identified as the Bond Fairness and Protection Act (BFPA). Arkansas Cities states ''that if enacted, the BFPA would clarify tax laws and regulations governing tax exempt bonds so that publicly owned utilities would be able to participate in the development of competitive electric utility markets.''[671] Duke asserts that the leasing of transmission facilities to an RTO is a viable option. Moreover, LPPC states that public power entities have to be allowed to participate in a way that permits them to retain sufficient operational control of their transmission systems to stay within the private use limitations. In addition, LPPC, Snohomish, Arkansas Cities and East Texas Cooperatives argue that public power entities need an opt-out provision if their tax exempt status is threatened. TEP recommends that the final rule contain a template for addressing how transactions can be administered if they involve the use of tax exempt facilities. TEP proposes that (1) an RTO should operate in a manner that either preserves the tax exempt status of such facilities or provides compensation to the facilities' owner to the extent it incurs economic harm; and (2) that an RTO should develop specific rules governing the operation and administration of tax-exempted financed facilities.

NRECA details the obstacles confronting cooperatives including the requirement that in order to maintain tax exempt status under Section 501(c)(12) of the IRS Code, at least 85 percent of a cooperative's income must come from the cooperative's members. If such member-derived revenue does not equal at least 85 percent of total revenue, then a cooperative would lose its tax-exempt status. Georgia Transmission argues that there is a real risk that participation in an RTO could result in a cooperative losing its tax exempt status if the revenue received from the RTO (assuming the RTO is not a member of a cooperative) exceeds 15 percent of the cooperative's total income. The revenue received from the RTO would stem from revenue attributed to use of the cooperative's transmission facilities controlled by the RTO.

One remedy to this problem, suggested by AEPCO and Wolverine Cooperative, is to increase an RTO's compensation to the cooperative to include a gross-up of net margins to cover the income tax expense. Under this approach, the RTO would pay the cooperative the full revenue requirement for the transmission facilities, including any other taxes. East Kentucky proposes that a conduit or a pass-through relationship between the RTO and the cooperative would satisfy the IRS restrictions and allow a cooperative to maintain its member-derived character. According to East Kentucky, the RTO would act as an agent for the cooperative by collecting the transmission revenues and holding these revenues in a trust on behalf of the cooperative. Furthermore, Georgia Transmission suggests that the Commission allow a cooperative to leave an RTO if it appears that it may lose its tax exempt status because of the level of RTO and other non-member revenue it expects to receive in a given year.

Another impediment to public power participation in RTOs is mortgage restrictions. AEPCO notes that under the terms of a typical RUS mortgage, either transfer of control of transmission assets to an RTO or a sale, unless authorized by RUS, would be an event of default. East Texas Cooperatives argues that the Commission should require all RTOs to accommodate mortgage restrictions by allowing cooperatives to retain control of their facilities until the mortgage restriction is lifted or a creditor or RUS approves the transfer. In its comments, RUS recognizes that development of RTOs may offer considerable benefits to RUS borrowers, and RUS states that it is exploring means to facilitate borrower participation consistent with the Rural Electrification Act and RUS's fiduciary duties to the U.S. Treasury and taxpayers.

According to several commenters,[672] many public power entities operate under explicit state constitutional restraints with respect to their ability to participate in the ownership of a privately-owned RTO.[673] Further, some state constitutions include restrictions on the use of public funds.[674] Several states, however, expressly authorize public power entities to join with other

[669] *E.g.,* Los Angeles, SoCal Cities, LPPC, APPA, Tacoma, NCPA, SRP, TAPS, EEI, NPPD and East Texas Cooperatives.

[670] *See, e.g.,* EEI, TAPS, SRP, Georgia Transmission, Arkansas Cities, Nevada Commission, PP&L Companies, TANC, Desert STAR, NCPA, Montana-Dakota Enron/APX/Coral Power and Tallahassee.

[671] *See* Reply Comments of Arkansas Cities at 6.

[672] *See, e.g.,* LPPC, NPRB, Snohomish, Clarksdale, MEAG and CAMU.

[673] For example, the Nebraska Constitution provides: ''No city, county, town, precinct, municipality or other sub-division of the state, shall ever become a subscriber to the capital stock, or owner of such stock, or any portion or interest therein of any * * * private corporation or association.''

[674] For example, the Colorado Constitution states: ''Neither the state, nor any county, city, town, or township shall lend or pledge credit or faith thereof, directly or indirectly, in any manner to, or in aid of, any person, company or corporation, public or private, for any amount, or for any purpose whatever; or become responsible for any debt, contract or liability of any person, company or corporation, public or private, in or out of the state.''

public entities in the ownership and operation of electric transmission facilities.[675] In addition, state and local laws impose additional restrictions on the activities and operations of public power entities that could affect the operations of any RTO in which they hold an ownership interest. For example, some laws prohibit the sale or lease of transmission facilities to a for-profit entity.[676]

In states in which laws allow a public utility district to sell or lease its transmission facilities to an RTO, the laws impose requirements on such sale or lease. For instance, Washington law would require the property to be offered in a competitive bidding process, and no sale could occur without voter approval.[677] Furthermore, LPPC notes that state and local laws in California, Florida, Nebraska, and Texas would require the approval of the City Council, the public utility commission, the governing board, or other governmental authority before a transfer of facilities could occur. CAMU and NPPD also state that many municipals and power authorities have statutory authority to condemn property and that it is unlikely that this eminent domain authority can be delegated to an RTO.

Enron/APX/Coral Power notes that an unwillingness to participate in an RTO for commercial reasons should render non-jurisdictional transmission owners ineligible for RTO services and savings. Moreover, Duke argues that public power must take the lead in resolving these issues for themselves. Duke notes that investor-owned utilities have overcome numerous obstacles to become RTO participants. Furthermore, Enron/APX/Coral Power argues that public power and other non-jurisdictional transmission owners that elect to share in the benefits of an RTO must be held to the same characteristics and functions as jurisdictional transmission owners. Cinergy suggests that the Commission commence regional technical conferences to address legal obstacles to public power entities' participation in RTOs and to explore possible alternatives to operational and functional integration of public power systems into RTOs.

Commenters also address issues relating specifically to PMAs. Many commenters support the expansion of the FPA to give the Commission jurisdiction over all transmission owners.[678] CREDA points out that PMAs are restricted by: (1) enabling statutes; (2) congressional appropriations; (3) the inability to grant indemnification without congressional approval; (4) the sovereign immunity doctrine; and (5) their load serving responsibilities. MLGW notes that other PMA restrictions include the TVA ''fence restriction,'' whereby, TVA's organic statute prohibits TVA from performing any transmission service that would result in the delivery of power generated by TVA outside the specified TVA service area. MLGW further notes that existing long-term contracts between TVA and its distributors are another barrier to RTO participation by PMAs. To remedy these problems, TVA and others[679] argue that the Final Rule should provide enough flexibility to ensure that public power obstacles can be addressed and mitigated.

On the issue of whether the Commission should consider special accommodation, commenters disagree over whether the Commission should provide incentives to public power entities in order to make RTO membership financially attractive. EEI and APPA urge the Commission to adopt an RTO policy that makes membership attractive to public power entities in terms of efficiency and benefits.

SoCal Edison is strongly opposed to the Commission providing incentives in the form of uniform grid-wide rates or transmission credits. SoCal Edison argues that these incentives are nothing more than inequitable cost shifts to retail ratepayers. Likewise, Duke argues that public power entities should not be provided with competitive advantages in order to encourage voluntary RTO participation.

In contrast, IMPA and SoCal Cities urge the adoption of a final rule that provides proper credits or compensation for facilities contributed to an RTO, including customer-owned facilities. Furthermore, East Kentucky states that return on equity can be mitigated by allowing cooperatives to earn a rate of return similar to investor-owned utilities. Vernon argues that the entitlement for transmission facilities contributed to the RTO grid and the appropriate level of compensation are matters that should not be determined nationally on a generic basis, but rather, should be decided in the context of each RTO. SRP supports PBRs and other incentives as long as they are applied to both public power entities and investor owned companies equitably. Metropolitan contends that it would not receive much benefit from any ROE incentives offered to RTOs because it is a public entity and because its asset base is so heavily depreciated. However, a replacement cost methodology could be of use in mitigating cost shifts for Metropolitan due to rolling in higher costs of other utilities. Oregon Office recommends that public power entities be eligible for the same incentives as offered others to the extent that the Commission regulates their rates.

A few commenters discuss issues relating to public power and the filing requirements. South Carolina Authority states that any RTO proposal should contain a detailed description of the efforts made by petitioners to accommodate the transmission facilities of publicly owned utilities. Similarly, SRP, APPA and LPPC recommend that the Commission require each RTO proposal to demonstrate: (1) how a good faith effort was made to accommodate public power participants, particularly deciding ownership structure; and (2) where public power entities are not included, why there are no reasonable terms and conditions under which the RTO could accommodate its participation. Lincoln and Cinergy essentially concur.

Commission Conclusion. We reaffirm our preliminary determination that a properly formed RTO should include all transmission owners in a specific region, including municipals, cooperatives, Federal Power Marketing Agencies (PMAs), Tennessee Valley Authority and other state and local entities. As noted by some commenters, public power and cooperative participation in RTOs will enhance the reliability and economic benefits of an RTO. Furthermore, participation by public power entities and cooperatives is vital to ensure that each RTO is appropriate in size and scope.

Virtually all commenters note that public power entities and cooperatives face numerous regulatory and legal obstacles regarding RTO participation. Commenters assert that these obstructions include: (1) IRS ''private use'' restrictions and the temporary regulations enacted to mitigate the ''private use'' restrictions; (2) the

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[675] For example, Washington law provides: ''Any two or more [Washington] cities or public utility districts or combinations thereof may form an operating agency * * * for the purpose of acquiring, constructing, operating, and owning plants, systems and other facilities and extensions thereof, for the generation and transmission of electric energy and power.''

[676] Nebraska law provides that: ''[T]he plant, property, or equipment of a public power district shall never * * * by outright sale, or lease, become the property or come under the control of any private person, firm, or corporation engaged in the business of generating, transmitting, or distributing electricity for profit.'' Nebraska Rev. Stat. § 70–646.01.

[677] *See* LPPC at 17.

[678] *See, e.g.,* LG&E, Otter Tail, WPSC, Alabama Commission, Montana Commission, and DOE.

[679] *See, e.g.,* CAMU, CMUA, STDUG, CREDA, NY ISO, Powerex, PP&L Companies, Desert STAR, CP&L, LPPC, MEAG and Tennessee Authority.

requirement that at least 85 percent of a cooperative's income must come from the cooperative's members (IRS Code Section 501(c)(12)); (3) RUS mortgage restrictions; (4) state constitutional restraints; (5) state and local laws; and (6) specific legal restrictions applicable to PMAs. In addition, commenters offer a variety of solutions to mitigate or eliminate these obstacles to public power participation in RTO formation and operation.

We acknowledge that public power entities face several difficult issues regarding RTO participation and we appreciate the potential solutions offered by numerous commenters. At this time, however, we will not analyze each of the specific resolutions proposed by the various commenters. Instead, on an RTO-by-RTO basis, we will examine submitted proposals that provide public power and cooperatives with the flexibility to join an RTO without jeopardizing their tax or mortgage status. We note, however, that the offered solutions must be consistent with the minimum functions and characteristics outlined in the Final Rule.

We are aware that some public power entities and cooperatives have found ways to participate in existing ISOs. For example, we approved the formation of the NY ISO contingent upon a ruling of the Internal Revenue Service that the formation and operation of the NY ISO would not jeopardize the tax-exempt status of the New York Power Authority.[680] Furthermore, we are encouraged by the recent efforts of the Member Systems of the New York Power Pool (NYPP) to include and accommodate the participation of Long Island Power Authority (LIPA) in the NY ISO. NYPP proposed language in their OATT that provides LIPA will not be required to provide transmission service where the provision of such service would result in the loss of its tax-exempt status for its bonds. NYPP also proposed additional scheduling protocols and procedures to ensure the continued tax-exempt status of LIPA. The Commission accepted the proposed language as described above.[681] We also note that there are two cooperatives Hoosier Energy Rural Electric Cooperative, Inc. and Wabash Valley Power Association that are members of the Midwest ISO.[682] We are hopeful that similar agreements between RTOs and public power entities and cooperatives can be reached to provide flexibility and achieve broad regional RTO participation by all entities.

We expect public power entities and cooperatives to participate fully in the collaborative process for forming RTOs. During the collaborative process, the Commission hopes that the parties will explore, in detail, the impediments and various solutions to public power and cooperative participation in RTOs. As discussed below with respect to the collaborative process, we will make staff resources available to assist in facilitating communication between all entities and in designing regional solutions to full RTO formation and participation. Moreover, in all filings under this Rule, we require a description of efforts made to accommodate participation by public power entities and cooperatives in RTOs.

We recognize that there is uncertainty regarding what may happen after the IRS temporary ''private use'' regulations expire on January 22, 2001. Accordingly, we intend to continue to support efforts to mitigate the ''private use'' and other tax restrictions. Furthermore, in its comments, RUS recognizes that the development of RTOs may offer considerable benefits to RUS borrowers. RUS states that it is exploring means to facilitate borrower participation in RTOs. The Commission welcomes the efforts of RUS to facilitate borrower participation in RTOs, and also encourages RTOs to seek ways to accommodate mortgage restrictions. It would be unfortunate if public power entities and cooperatives were not able to participate in RTOs and share in the benefits available in a regional organization because of tax rules and other government restrictions.

2. Participation by Canadian and Mexican Entities

In the NOPR, the Commission noted that currently, electricity trading regions exist across national borders and therefore, Mexican and Canadian involvement in RTO formation would be beneficial to both countries, as well as to the United States.[683] The Commission asserted that regional institutions should include all market participants in order to provide direct access to information and the benefits of non-pancaked rates. The NOPR also proposed that in order to prevent wasteful duplication of grid facilities, reliability standards implemented by RTOs must be acceptable to the affected nations.[684] The Commission also emphasized that Canadian and Mexican authorities would be responsible for approving prices and other terms and conditions of transmission service provided over any RTO transmission facilities located in their country.[685]

Comments. The U.S. entities that submitted comments on this issue support the efforts by the Commission to encourage participation in RTOs by Canadian and Mexican entities.[686] For example, PG&E states that given the high degree of operational interconnection between our national grid and components of their systems, participation by these entities is beneficial.

Similarly, some Canadian entities believe that significant benefits can be achieved by trading over ''natural'' or ''appropriate'' transmission regions that do not necessarily stop at the border.[687] Other Canadian entities welcome the opportunity to participate in the RTO proceedings and support the Commission's efforts to encourage international collaboration.[688]

Canadian entities are concerned with sovereignty issues and urge the Commission to adopt flexible RTO rules that allow voluntary participation by Canadian utilities.[689] According to the Manitoba Board and Ontario IMO, one option in this regard would be to allow members of an RTO the freedom to conduct transactions—through a contractual relationship—at the international border with foreign utilities that do not join a cross-border RTO. Furthermore, Canada DNR asserts that a decision not to participate in an international RTO by a Canadian jurisdiction should not place entities in Canada engaged in trade with United States at a disadvantage. Grand Council *et al.* proposes that the Commission sever the Canadian issues from this proceeding and open a separate docket to examine the international issues raised by the restructuring of electricity markets. Grand Council *et al.* urges the Commission to cooperate with Canada and Mexico to establish a genuine tri-national consultative process in order to resolve international issues based on an adequate record. Alberta notes that each

[680] *See* Central Hudson Gas & Electric Corp., *et al.*, 83 FERC ¶ 61,352 at 62,405 (1998).

[681] *See* Central Hudson Gas & Electric Corp., *et al.*, 88 FERC ¶ 61,138 at 61,402–03 (1999).

[682] *See* Midwest Independent Transmission System Operator, Inc., *et al.*, 84 FERC ¶ 61,231 (1998).

[683] FERC Stats. and Regs. ¶ 32,541 at 33,758.

[684] *Id.* at 33,758–59.

[685] *Id.* at 33,759.

[686] *See* PG&E, Desert STAR, Michigan Commission and Industrial Consumers.

[687] *See, e.g.*, Ontario Power, H.Q. Energy Services, BC Hydro and Canada DNR.

[688] *See, e.g.*, Powerex, CEA, Manitoba Board, British Columbia Ministry, Alberta, Canada DNR, BC Hydro and Ontario IMO.

[689] *E.g.*, Manitoba Board, British Columbia Ministry, BC Hydro, Canada DNR, CEA and Ontario Power.

individual Province has jurisdictional responsibility for the development of the electrical industry within each Providence and accordingly, only the Province has the jurisdiction to pass legislation to develop a competitive electricity market.

Commission Conclusion. After reviewing the comments, we continue to believe that Canadian and Mexican involvement in RTO formation and operation would be beneficial to both countries, as well as to the United States. As we stated in the NOPR, expansion of electricity trade in the North American bulk power market requires that regional institutions include all market participants so that everyone may enjoy direct access to market information and the benefits of non-pancaked transmission rates. Commenters from the United States and Canada agree that significant benefits can be achieved by trading over ''natural'' or ''appropriate'' transmission regions that do not necessarily stop at the border.

We note first that we are pleased with the level of participation in our proceedings by Canadian parties, and we encourage their continued participation as RTO formation progresses. We especially appreciate the RTO Consultation Conference sponsored by Natural Resources Canada in Ottawa in November 1999.

In response to Canadian comments, we point out that the Final Rule makes participation in an RTO voluntary for U.S. transmission owners, and participation is certainly voluntary for Canadian transmission owners. Further, we emphasize that our RTO Rule does not in any way require competition in retail electricity markets, whether they are located in the United States under state regulation or in Canada under provincial regulation. For those Canadian entities that want to join an RTO, the Final Rule is flexible: they may propose a cross-border RTO or a Canadian-only RTO that is compatible with the Rule. The Final Rule is not exclusionary: Canadian entities are not precluded from joining a cross-border RTO.

Several parties were concerned that a cross-border RTO would have its rates, terms, and conditions subject to the rate jurisdiction of at least two regulators. If a cross-border RTO forms, we will be open to proposals for innovative approaches for jointly overseeing a cross-border RTO with domestic and foreign utilities. For example, one approach might be for the cross-border RTO to try to develop a proposal acceptable to both regulators, with the understanding that any regulatory difficulty would normally be referred back to the RTO for resolution and resubmission to both regulators. Another approach might be to have different but complementary rate designs in the two countries.

In the case of a Canada-only RTO, some Canadian transmission providers believe that having contractual and other agreements for coordination between separate RTOs aross the border is better than having a cross-border RTO. However, some Canadian transmission customers are concerned that this would maintain a lack of standardization of market rules across the border. The RTO Rule is intended to permit a U.S. RTO on the Canadian border to develop contractual and other agreements for coordination with its Canadian RTO neighbor. Further, we have added a new minimum RTO function that an RTO must ensure the integration of reliability practices with other regions in the same interconnection and market interface practices with other regions. We clarify here that this provision applies to integration with interconnected regions in Canada and Mexico.

For either a cross-border or a Canada-only RTO, we acknowledge the sovereign authority of Canadian governments over Canadian entities and transactions that take place in Canada. Moreover, we re-emphasize that our Rule does not affect the authorities of Canadian government entities to approve prices and other terms and conditions of transmission service provided over any transmission facilities located in Canada. These conclusions apply equally to Mexico.

We encourage Canadian and Mexican entities to participate in continued RTO consultations and, if appropriate, formation and filings for cross-border RTOs. In particular, we urge Canadian and Mexican entities to attend the appropriate regional workshops to be held in the spring of 2000. These workshops will provide a forum for initial discussion of the issues associated with a cross-border RTOs.

Regarding the suggestion to establish a tri-national consultative process with Canadian and Mexican authorities to resolve international electric industry issues, we note that there are existing institutions and processes for resolving international disputes. The RTO process is just getting underway, and it is not clear that significant international disputes will develop or, if they should develop, that they would require a non-traditional method of resolution. Indeed, the RTO itself through its dispute resolution process may provide a new and quicker way to resolve some disputes.

3. Existing Transmission Contracts

In the NOPR, the Commission asked for comments addressing what the appropriate treatment should be for existing transmission agreements when an RTO is formed. We noted that in Order Nos. 888 and 888–A, the Commission specifically chose not to abrogate existing requirements contracts and transmission contracts when the utility filed an open access transmission tariff.[690] We stated, however, that an RTO represents an entirely different context. In the NOPR, the Commission recognized the importance of balancing a uniform approach for transmission pricing with the equities inherent in existing transmission contracts.[691] Furthermore, we noted that the potential financial impact of giving up an advantageous transmission arrangement may serve as a disincentive to joining an RTO. In the NOPR, we proposed to address the issue of existing transmission contracts on an RTO-by-RTO basis, rather than resolve the issue generically.[692]

Comments. Many commenters argue that the Commission should preserve and protect existing transmission contracts.[693] These commenters note that existing contracts represent negotiated rights and obligations achieved through mutual negotiation. SRP believes that the Commission should grandfather existing transmission contracts in order to protect customers from cost shifts and prevent uncertainty in the marketplace. Turlock argues that the preservation of existing contracts, while cumbersome, is the bedrock of predictability and reliability and a key element of contract law. NPRB states that existing contracts should be honored until the contract expires or until the parties come to a new agreement. STDUG asserts that in order to be properly inclusive, an RTO must take members as it finds them, existing contracts, warts, and all. In contrast, CP&L asserts that the elimination of grandfathered agreements to the greatest extent possible ensures the most level playing field for all market participants.

[690] FERC Stats. & Regs. ¶ 32,541 at 33,757.

[691] *See id.* at 33,757–58.

[692] *Id.* at 33,758.

[693] *E.g.,* TANC, Turlock, UAMPS, Desert STAR, CMUA, Sithe, Georgia Transmission, Lincoln, PG&E, NPRB, NCPA, Great River, NRECA, Loveland Customers, San Francisco, Platte River, Florida Commission, Nevada Commission, DOE, Wolverine Cooperative, Tri-State, CREDA, EPSA, Big Rivers, SPP, SoCal Cities, TEP, PJM/NEPOOL Customers, Metropolitan, STDUG and PacifiCorp.

A few commenters propose a reasonable transition period to allow parties to existing contracts to conform their arrangements to an RTO tariff.[694] EPSA notes that the transition period should be of sufficient length to reduce the financial and other burdens on the customer and on the original transmission provider. PSNM argues that at a minimum, a transition period of as long as ten years is needed to move the existing transmission contracts to RTO service. Furthermore, TAPS proposes that the Commission provide entities with an open season for transmission customers to choose to terminate or switch service under the terms of an RTO tariff. Alternatively, TAPS suggests that the Commission apply a just and reasonable standard to all transmission customers who seek contract modifications. Regarding contract modification, Southern Company asserts that in order to promote fairness, both parties to a contract must have an equal opportunity to modify the existing agreement. In addition, Entergy argues that the Commission should encourage all entities to re-negotiate existing contracts.

Several commenters support the Commission's preference that issues relating to the continued validity of existing transmission contracts be addressed on an RTO-by-RTO basis.[695] WPSC argues that treatment of existing transmission contracts within a particular RTO should be consistent. Turlock urges the Commission to proceed with caution when addressing existing contracts. On the other hand, PSE&G asserts that the Commission should not address the treatment of existing contracts on a case-by-case basis because this leads to arbitrary and inconsistent results. Instead, PSE&G and Dalton Utilities argue that the Commission should address the issue of existing transmission contracts on a generic basis consistent with Order No. 888 and the Mobile-Sierra doctrine (recognizing the need to preserve the sanctity of contracts where possible).[696] Sithe and NRECA concur that a generic policy is appropriate.

Cal ISO argues that the Commission's policies on existing contracts deserve revisiting, at a minimum for the limited purpose of conforming scheduling and metering rules to those of the RTO/control area operator. Cal ISO states that it has experienced the challenges of workability when the ISO was required to honor existing contracts, but not permitted to interpret them or conform their scheduling rules to those of the regional organization. Cal ISO notes that it has experienced the most significant market inefficiencies associated with existing contracts in the area of scheduling and information gathering.

A few commenters note that not honoring existing contracts would create disincentives for both transmission customers and owners to join an RTO.[697] For example, CMUA and Georgia Transmission argue that the financial impact of giving up an advantageous transmission arrangement would be a significant disincentive to RTO membership.

Commission Conclusion. At this time, we continue to believe that it is not appropriate to order generic abrogation of existing transmission contracts. We recognize that existing contracts represent negotiated rights and obligations achieved through mutual negotiation. However, in PJM [698] and the Midwest ISO [699] we adopted the rationale that it was unreasonable and discriminatory to maintain the pancaked rates in existing contracts for others when transmission-owning utilities had designed a non-pancaked rate approach for their own transactions. In our examination of existing contracts, we intend to balance the preference for preservation of existing contracts with the importance of consistency in transmission pricing and the elimination of pancaked rates.

As the above comments demonstrate, there is no consensus on how the Commission should manage the transition from existing transmission contacts to RTO service. In fact, parties offer diverse and conflicting views as to what the Commission should do regarding existing transmission contracts. Some commenters would have us let all contracts run their course with no opportunity to modify or terminate. Others advocate an elimination of existing agreements to the greatest extent possible. Yet others argue for a transition period ranging in duration for up to ten years to move existing transmission contracts to RTO service.

Rather than adopting one extreme position or the other, we will take a measured approach with regard to the treatment of existing transmission contracts. We intend to address the issue of existing transmission contracts on an RTO-by-RTO basis, rather than resolve the issue generically. Accordingly, each RTO can propose whatever contract reform is necessary, including the limited changes suggested by the Cal ISO for the limited purpose of conforming scheduling, information gathering, and metering rules to those of the RTO. To this end, we encourage each RTO to address how and when it might convert existing contracts and submit a contract transition plan that contains specific details about the procedures to be utilized involving the conversion from existing contracts to RTO service. Again, our goal in reviewing existing transmission contracts and contract transition plans is to balance the desire to honor existing contractual arrangements with the need for a uniform approach for transmission pricing and the elimination of pancaked rates.

4. Power Exchanges (PXs)

The NOPR described the apparent advantages and disadvantages of having a power exchange coincident with an RTO. As further described in the NOPR, supporters state that PXs can reduce price volatility by providing price transparency, reduce the impact of defaults by spreading transaction risks among all participants through credit standards and reserve fund requirements, facilitate risk hedging by providing a basis for a futures market, and help facilitate retail access programs. Detractors argue that the principal functions of a PX are not natural monopoly functions. They contend that PXs, compared with bilateral markets, force participants to buy and sell electricity using standardized contracts, which may not suit their particular needs. They further argue that competition within the electricity market and its full benefits can only be achieved if there is competition for the PX market.

The NOPR left it to each region to determine whether there is a need for a power exchange and whether the RTO should operate it.[700] The NOPR said that the Commission will accept any RTO proposal that includes a power exchange in its design as long as its operation of the power exchange does not compromise its independence as a

[694] *See, e.g.,* Williams, EPSA, First Energy, Duke, PSNM, LG&E, PGE and MidAmerican.

[695] *See, e.g.,* WPSC, Great River, DOE, ICUA, Entergy, TDU Systems, TEP, South Carolina Authority, MidAmerican, SNWA, UAMPS and TAPS.

[696] *See* United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 338 (1956); FPC v. Sierra Pacific Power Co., 350 U.S. 348, 353 (1956).

[697] *E.g.,* CMUA, Desert STAR, Georgia Transmission, Wolverine Cooperative, Cal ISO, Entergy, Tri-State, SNWA, Metropolitan and TEP.

[698] *See PJM,* 81 FERC ¶ 61,257 at 62,280–81 (1997).

[699] *See* Midwest Independent Transmission System Operator, Inc., *et al.,* 84 FERC ¶ 61,231 at 62,169–70, *order on reh'g,* 85 FERC ¶ 61,372 at 62,418–20 (1998).

[700] FERC Stats. and Regs. ¶ 32,541 at 33,760.

transmission service provider. The Commission sought comments on a number of questions related to power exchanges, including whether regional flexibility is appropriate and how RTOs should deal with an independent power exchange.

Comments. Commenters' views on power exchanges are mixed. The largest group of commenters basically agree with the NOPR.[701] A smaller group of commenters recommend that the Commission require that RTO applications include provisions for a power exchange,[702] with some recommending that the power exchange be internal to the RTO [703] and some recommending that the PX be independent of the RTO.[704] CalPX argues strongly that a power exchange should be separate from the RTO, given the continuing need to separate market and transmission functions; the need for market transparency to facilitate determination of whether congestion is being exploited; the need to provide a credible reference price for new retail choice market entrants; and the potential need for the RTO and power exchange to serve differing geographic areas. CalPX also submits that there is no concrete evidence that an RTO-operated power exchange will be more efficient and economical than an unrelated power exchange. NYMEX agrees that an RTO should be permitted to operate a power exchange, as long as a proper code of conduct is in place. PJM points to its success with a combined ISO/power exchange.

Another group of commenters argue that power exchanges should not be included in RTOs, but should be allowed to occur naturally as needed.[705] Elaborating on this point of view, Salomon Smith Barney advises that the power exchange should not be in the RTO because it could throttle innovation and that the Commission should let the market decide. If there are really advantages to be gained, as some claim, from the operation of a single power exchange associated with the RTO, then such a power exchange will naturally develop. Florida Power Corp. argues that, while a region may prefer that its RTO closely coordinate with the power exchange, the two should not be part of the same organization because there is a fundamental difference in the business objectives of the two .

[701] *See, e.g.,* Entergy, NJBUS, NY ISO, TDU Systems, Wisconsin Commission and UtilitCorp.

[702] *See, e.g.,* Pennsylvania Commission, Duke and California Board.

[703] *See, e.g.,* PJM, ISO-NE and TAPS.

[704] *See, e.g.,* EPSA and MidAmerican.

[705] *See, e.g.,* APX, SMUD, Southern Company, Tri-State and Lincoln.

Similarly, EPSA contends that the Commission's vision of an RTO being an entity independent from all generation and power marketing interests is fundamentally incompatible with an RTO-run power exchange. Nevada Commission offers that a power exchange is not necessary to the formation of an RTO. And while PG&E sees every region needing a real-time balancing market regardless of whether it is run in-house by the RTO, PG&E also prefers that markets should otherwise be left to develop on their own accord.

Comments were received on additional aspects of the power exchange concept. PG&E argues that an RTO should not be allowed to use control of a power exchange to alter or cap prices set by the market. LG&E submits that the RTO should be required to be the provider of last resort for ancillary services, although market participants should not be required to purchase from the RTO. NASUCA notes that the NOPR does not cover some important power exchange issues such as exactly which markets would be included. NASUCA recommends that a NOI on power exchanges and related power market issues be initiated soon after the final rule.

Several commenters state that multiple power exchanges in a region should have equal standing before the RTO.[706] FTC, however, recommends that the Commission assess whether competition is feasible in power exchange services. Similarly, CalPX notes that multiple power exchanges may hurt the market's function because each power exchange would be small, and therefore would not offer high levels of depth, liquidity and efficiency. NYMEX counters that there should be no credence given to the idea that one power exchange should enjoy any form of artificial franchise vis-a-vis others.

Commission Conclusion. The NOPR proposed leaving it to each region to determine whether there is a need for a power exchange and whether the RTO should operate the power exchange. We have Decided to adopt the NOPR proposal. As the commenters have pointed out, there are advantages and disadvantages to the inclusion of a PX in the RTO structure. We do not believe that including a PX as part of the RTO structure would necessarily preclude the market benefits associated with bilateral transactions. We believe an RTO can accommodate both a bilateral market and a PX market. As the individual structures of the various RTOs supported by the regions are likely to be quite varied, we think that it is best to let market preferences dictate the form of any one or more regional power exchanges and whether the RTO should operate a power exchange.

[706] *See, e.g.,* Duke, Florida Power Corp. and Desert STAR.

5. Effect on Retail Markets and Retail Access

The NOPR addressed the impact of RTOs and any associated PXs on retail competition and the states' jurisdiction over retail competition. For example, the Commission found that RTOs will enhance the effectiveness of retail competition:

> We believe that the likelihood of success for existing and planned retail choice initiatives is significantly enhanced if the Commission can ensure fair and efficient access to a regional market without pancaked transmission access charges, and that we need to take steps beyond Order No. 888 to accomplish this.[707]

In addition, the Commission found that an RTO does nothing to interfere with the state's authority to decide retail access policy, but asked whether a PX is necessary for successful retail competition.

Comments. Several commenters state that RTOs were either essential or of great benefit in the implementation of retail competition.[708] Mid-Atlantic Commissions notes that PJM has worked closely with the Pennsylvania, New Jersey and Delaware Commissions to assist with the implementation of their retail choice legislation in an organized fashion, while maintaining that the grid will be operated in a reliable fashion without any major economic or operational changes. According to Mid-Atlantic Commissions, this has also further provided those states in the region that have not implemented retail choice with a stable organization that continues to maintain reliability.

A few commenters express concern that the Commission's RTO policy could threaten the states' ability to control the pace of retail access and retail competition.[709] South Carolina Commission counsels that the Commission should try to avoid affecting retail restructuring through its efforts to establish an RTO process. Central Maine raises the concern that retail choice programs already developed in concert with existing ISOs may be adversely impacted by any changes to such ISOs that are found to be necessary for them to conform to the RTO requirements (*e.g.*, energy service

[707] FERC Stats. and Regs. ¶ 32,541 at 33,704.

[708] *See, e.g.,* TXU Electric, DOE, First Rochdale, Illinois Commission and Williams.

[709] *See, e.g.,* Iowa Board and Puget.

company and other load serving entity contracts entered into in reliance upon the existing ISO market structures).

Puget views allowing RTOs to make FPA section 205 filings that unilaterally propose changes to the RTO tariff as conflicting with the Commission's commitment to respect the retail access efforts of the individual states. Puget argues that a unilateral decision by an RTO to provide transmission service to a retail customer and make that customer an eligible customer under the *pro forma* tariff would force states without retail access to accept such access as a *fait accompli.* Puget also fears that the term ''market participant'' as ultimately defined may include any entity that buys or sells electric energy in the RTO's region or in any neighboring region that might be affected by the RTO's actions. If so, since market participants must also have the option of self-supplying or acquiring ancillary services from third parties, this further suggests that retail customers may have the ability to acquire transmission service regardless of whether the affected state has yet decided retail choice and stranded cost recovery issues. Industrial Customers, however, question the legal basis for Puget's apparent suggestion that utilities be allowed to decide which retail customers may access RTO transmission.

EPSA contends that, while states tout each state's rights to protect its retail native load customers, some actions taken under this banner to limit exports of power actually disadvantage adjoining state's retail customers or participants in the bulk power markets. Therefore, the Commission should move forward with a rulemaking to assure full transmission comparability for retail customers of all states, and to prevent individual states from continuing to disadvantage each other and to prevent individual utilities from continuing to disadvantage other market participants. New York Commission also submits that this proceeding is not the place to address the issue of preemption of state jurisdiction over bundled retail electric sales.

TAPS raises the question of jurisdictional conflict as to which facilities need to be regulated at the federal or state level, and whether the policies of the Commission toward open access will be undercut by transmission owners using the seven factor transmission/distribution classification test to place new generation at a disadvantage relative to existing generation owned by the transmission provider. TAPS contends that the Commission must take steps to ensure that RTOs contain the appropriate facilities and that refunctionalization of transmission to distribution does not interfere with competition by creating RTOs that control little or no transmission.

Another concern expressed is that RTOs may cause cost shifting to retail customers that could interfere with restructuring.[710] As to the impact of the power exchange on retail competition, both CalPX and MidAmerican argue that power exchanges assist in the effectiveness of retail competition programs by providing transparent and credible reference prices.

Commission Conclusion. We continue to be persuaded that RTOs can positively affect each state's implementation of its retail choice program, without interfering with those states that have not yet adopted such programs. As noted by commenters, existing ISOs have already successfully facilitated retail choice programs in areas where only some of the states have adopted such programs, and the ISOs were able to do so without clashing with or frustrating the other states that have not undertaken such programs. We do not believe that an RTO could interfere with a state's decisions on whether or how fast to implement retail choice within its borders, either through the RTO's Section 205 filing authority or otherwise through the RTO's jurisdictional obligation to provide non-discriminatory and non-preferential transmission service.

Commenters pointed to potentially extensive reclassification of transmission facilities to local distribution as part of the unbundling of retail rate schedules to implement retail choice programs, and how this might lead to RTOs that are ''empty vessels'' with little significant transmission under their control. We agree that RTOs must control all transmission facilities that are necessary to support competitive wholesale power markets. For this reason, we specified the scope, configuration and operational control requirements adopted in this Final Rule. We will judge any proposed reclassification on a case-by-case basis. We note that any reclassification of transmission facilities to local distribution will require Commission approval and will not remove from the Commission's jurisdiction any facilities used to deliver power to wholesale customers. Furthermore, under the principle of open architecture (discussed *supra* in section III.F), the Commission expects RTOs to remain flexible such that, if over time circumstances should change and certain facilities need to be reclassified as transmission, procedures will be in place to do so.

With regard to RTO pricing causing transmission cost shifting that adversely affects retail choice customers, this issue is discussed in the Transmission Ratemaking section of this Final Rule.[711] The Commission will continue to review transmission rate proposals to ensure that they are just and reasonable, and not unduly discriminatory.

Finally, on the matter of whether a power exchange is needed to facilitate states' retail choice programs, it is our view that, to the extent that a region forming an RTO chooses to voluntarily establish an RTO-affiliated power market, we anticipate that any such power exchange would provide retail choice customers with transparent and credible reference prices for power and other information that otherwise might not be available.[712]

6. Effect on States with Low Cost Generation

In the NOPR, we recognized that states with relatively low cost power are concerned that an RTO would result in local utilities selling their low cost power to other states.[713] However, we noted that a state that is low cost today may not be low cost tomorrow without an RTO in its area.[714] In addition, we stated that utilities that now have low cost generation will help assure access to future low cost generating plants by participating in an RTO and that new low cost generation plants are more likely to be attracted to regions with a well-functioning regional market governed by an RTO. We sought comment from state commissions regarding how an RTO in their state would affect power costs.

Comments.—A number of commenters raise concerns about the effect of RTOs on states with low cost electricity. These concerns center around one issue—that the costs of creating an RTO may outweigh the benefits.

South Carolina Commission argues that customers in South Carolina enjoy very high quality service and pay some of the lowest rates. Duke power concurs, noting that, it is not necessarily true that North Carolina and South Carolina will conclude that sufficient long-term benefits exist for these states to justify costs of RTO membership. Duke argues

[710] *See, e.g.,* LG&E and Southern Company.

[711] *See supra* section III.G.

[712] For a further discussion of PXs, *see supra* section III.H.4.

[713] FERC Stats. and Regs. ¶ 32,541 at 33,722.

[714] *See id.*

that any proposed RTO should be shown to provide tangible benefits to the relevant region.

Alabama Commission believes that RTOs will cause states to lose the efficiency of integrated systems and lead to retail competition, whether it is in the interest of customers or not. Southern Company agrees, noting that due in large part to the low cost status of southeastern states, they are proceeding cautiously with retail competition and restructuring initiatives. This does not mean that these states are ignoring the potential benefits of restructuring. Indeed, Southern Company notes that states in its service territory are actively studying the potential advantages and disadvantages of retail competition but have not yet concluded that the potential benefits outweigh the costs and risks associated with changing the current industry structure.

SMUD points out that it has not joined the Cal ISO over similar concerns. It indicates that its customers already enjoy low cost electricity and that participation in the Cal ISO could not ensure that SMUD's retail rates would be any lower, and on the contrary, the cost of participation would cause rate increases.

Kentucky Commission indicates that inefficiencies may occur for a variety of reasons and examples of inefficiencies include: multiple RTOs in a small region; several layers of governance within one RTO; and too many tasks shifted from the RTO members to the RTO itself. Kentucky Commission argues that if the proposed transmission organizations are not operated at levels of maximum efficiencies and minimum reasonable costs, the Commission will have failed to promote one of its primary objectives, the growth and success of the wholesale power market. Kentucky Commission further argues that the Commission must be mindful of these costs in developing rules for the establishment of RTOs.

Commission Conclusion. We are mindful of the potential costs of setting up and running an RTO, but we anticipate that the collaborative process will result in an RTO proposal that incorporates a design that, overall, increases the existing level of transmission system and market efficiency for each region. As we discuss more fully in the Scope, Implementation and Benefits sections of this Final Rule, we are taking a results-oriented, practical approach to establishment, organization, implementation and operation of RTOs. We do not expect that regions with no existing institutions will necessarily invest in new, high-cost RTO infrastructure. Instead, such a region may propose an RTO that relies on existing infrastructure to accomplish its mission. However, we expect the RTO to satisfy the minimum characteristics and functions and to improve the efficiency of regional transmission service.

In response to the concern of low cost states that RTOs could result in exports of their low cost power to other states, we do not believe that an RTO will cause utilities to sell their lowest cost power out of state. While retail choice arguably might lead to low cost power being sold out of state because incumbent utilities no longer have an obligation to serve local in-state loads, this would occur with or without an RTO in the region. Where there is no retail choice, our Final Rule does not affect a state commission's authority to require a utility to sell its lowest cost power to native load, as it always has. We point out that, if the utility's transmission is operated by an RTO and its higher cost power can be sold more readily to new, more distant customers, this will lead to recovery of more capital costs and lower retail rates. In the long term, low cost states may benefit from an RTO that facilitates expanded access to wholesale electricity markets, increasing the choice of low cost resources available to utilities as they acquire new power resources.

7. States' Roles with Regard to RTOs

In the NOPR, we noted that states want a role in the governance of any RTOs for their states, and we proposed to be flexible in accommodating the states' needs.[715] The NOPR encouraged RTO design to accommodate appropriate state oversight, especially with regard to planning and siting new multi-state transmission facilities. We sought comments on the appropriate state role in RTOs on these and other RTO matters.

Comments. Comments on the states' roles in RTO development and governance were fairly extensive, with by far the greater percentage of comments supporting a strong and clearly defined state role. Comments can be grouped into four primary categories: (1) governance; (2) formation; (3) siting and planning authority; (4) regional regulation.

Governance. Almost all commenters on this issue expressed support for a clear state role in governance; however, there were differences as to exactly what that role should be. Some commenters believe that states should be allowed to determine their own role in governance, either as members of advisory panels to the board of directors, as voting members of the board, as non-voting members of the board, or having authority to appoint board members. Some commenters, however, feel strongly that states should not be permitted to be voting members of boards.

Commenters argue that the appropriate state role in an RTO is a matter of local control. For example, Northwest Council states that the Commission should not set restrictive rules on the type of state participation in RTO governance, but should allow the states to propose to the Commission the kind of roles they view as appropriate, *e.g.*, voting members of a stakeholder board, *ex officio* status on an independent board, and so forth.

The California Board suggested that state officials should be allowed as either voting or non-voting members. Los Angeles has no objection to state board membership, either voting or non-voting, if a state has determined that a government official can best represent that state's interests. The Washington Commission agrees that states should be able to define their own role. Mid-Atlantic Commissions note that they have a Memorandum of Understanding with the PJM ISO Board of Managers to facilitate communication and promote a cooperative relationship.

Some commenters, however, think that state officials should not have voting membership on boards of directors since that could raise conflict of interest problems where the state official would have to approve decisions of the board while sitting as a regulator. For example, Minnesota Power believes that state cooperation will be enhanced if state officials participate as members of an RTO advisory board, but they should not participate as voting members of an RTO because the RTO process could be compromised by parochial state politics. ISO–NE agrees, pointing out that some states' conflict of interest laws may expressly prohibit such service, and that it might be difficult for an official from one state to make decisions as a board member that are good for residents of all states encompassed by the RTO.[716] WEPCO believes the appropriate role of the states in RTO governance includes active participation in regional planning efforts and continued oversight of siting of new transmission facilities. In addition, many commenters supported

[715] FERC Stats. and Regs. ¶ 32,541 at 33,724.

[716] *See also* MidAmerican, Montana-Dakota, PSNM, East Kentucky and NPRB.

an advisory role for state officials, through advisory boards.[717]

Formation. Numerous commenters supported a role for states in the formation of RTOs. ISO–NE points out that the states in its region had a significant role in the development of the ISO. In addition, the California Board argues that states should have a role in determining the structure of the RTO and any other market institutions that are formed to serve the citizens of their respective states. California Board further notes that mechanisms to ensure that states' interests are protected might include statutory or regulatory reliability criteria; independent market monitoring by the states or requiring market monitoring reports to be provided to the state; and accountability to the states to ensure adequacy of transmission and generation planning.

The Michigan Commission notes that most states have ittle direct authority to order the development of an RTO, especially when the RTO encompasses several states. According to the Michigan Commission, at best state commissions should serve in an advisory role as the utilities develop the structure and guidelines of the RTO proposal. The Michigan Commission, however, joins a few other states in urging the Commission to defer to state recommendations once the basic RTO characteristic and functional guidelines have been met.

NARUC comments extensively on the potential collaborative process and the importance of state participation in this process and other steps in the formation of RTOs. To achieve the public policy goal of assuring reliable service at an affordable cost, NARUC argues that states should fully participate in RTO development and formation, particularly in matters for end-use native load customers. NARUC notes that based on some states' retail choice or ISO experiences, state oversight can play a significant role in assuring a well-functioning ISO and competitive wholesale and retail markets.

NARUC further suggests that once RTOs are formed, continuing interaction is necessary, and market development and evolution will be continuous. NARUC believes that RTO formation must continue to be a dynamic process requiring continuing dialogue between FERC and the states. NARUC further believes that once organizations are formed and approved, some type of formal reporting to FERC and the states by the organizations on an annual basis would be appropriate.

Nine Commissions suggests that state commissions are well positioned to balance the competitive motivations of utilities in the RTO formation process with the interests of all other stakeholders in defining markets in their respective regions and conforming the RTO boundaries to those markets. According to Nine Commissions, the state commissions' continued cooperation with FERC will ensure that the mutual public interests of providing reliable electric service will be met, and that market participants in every region of the country will be treated comparably.

Siting, Planning and Reliability. A number of commenters, many state commissions, and quite a few other parties, argue strongly that the Commission should be careful not to preempt traditional state regulatory authority in promulgating its rule. In particular, commenters suggest that the Commission should not usurp state authorities over siting, planning, and reliability of the transmission system. Some commenters proposed solutions to state/Federal jurisdiction issues in the RTO context, such as joint state/Federal review bodies. The Alabama Commission suggests that FERC should not take any action that would infringe on state jurisdiction.

South Carolina Commission asserts that transmission siting should remain in the hands of the states and local governments. South Carolina Commission further asserts that states must continue to have a significant role with regard to matters of reliability for end-use native load customers. The Iowa Board concurs and suggests that the Commission's RTO policies cannot alter states' continued interest in local matters such as transmission and generation siting, local transmission and distribution interface issues, adequacy of generation and transmission, service quality, and retail rates.

The Montana Commission notes that in roughly half the states with siting laws the function is not vested in the regulatory commission, but rather in a separate energy policy, environmental or commerce agency. They recommend that the Commission amend the language in the Final Rule to make it clear that the Commission does not intend to preempt state siting authority as part of this NOPR.

UAMPS warns that RTOs may create a separation between generation planning and transmission planning that endangers reliability. UAMPS argues that states must be left with authority to assure reliability and that retail competition issues should also be left to the states. UAMPS suggests that because state cooperation and participation will be so critical to an RTO's effectiveness, in addition to the four minimum characteristics the Commission has proposed, RTOs should be required to provide specifically for significant state involvement in their development and operation. Allegheny, on the contrary, states that system operations in an RTO will be pursued for the good of the RTO service area, not of any one state. Allegheny notes that if that fact yields a dilution of state authority it must be the price paid for RTO benefits.

Regional Regulation. A number of commenters propose or support regional regulatory cooperation or joint state/Federal sharing of jurisdiction. The Kentucky Commission proposes the creation of a Federal/state ''joint board,'' that is styled similarly to the Universal Service Joint Board currently used by the Federal Communications Commission, state utility commissions, and other parties. The Kentucky Commission suggests creating this voluntary Board to develop and review standards for transmission expansion. The Joint Board would include participation from FERC, state commissions, RTOs, and other interested parties. The Joint Board would also convene ad hoc committees to review specific transmission expansion proposals. These committees would include the participants described above, and would include representatives from regulatory commissions in states where the expansion is proposed. The RTO would present the *ad hoc* committee with a plan for transmission expansion with appropriate documentation for need, cost effectiveness, and alternatives. The committee would in turn pass on its recommendation or refusal of support for the plan to the specific state commissions for their official approval. The Kentucky Commission believes that such an arrangement could avoid Federal/state conflict while allowing both levels of government to exercise appropriate jurisdiction. In addition, ISO–NE points to existing regional regulatory groups such as NECPUC that could continue to provide valuable assistance to the Commission in the collaborative process to encourage RTO formation envisioned in the NOPR.

Nine Commissions argues that an appropriate regional oversight venue will lead to more consistent treatment of issues and parties between state and Federal regulatory forums. With appropriate deference by both FERC and the states, such a regional venue could

[717] *E.g.,* ISO–NE, PJM, Midwest ISO, MidAmerican, Project Groups, PSNM, Iowa Board, Arizona Commission and UAMPS.

obviate the need for many parties to expend redundant resources to participate in multiple state and Federal regulatory processes for matters relating to transmission and RTOs.

Nine Commissions notes that one possible mechanism to effectuate such a regional venue is interstate compacts, which are provided for in the Administration's proposed electric industry restructuring legislation. Nine Commissions argues that regional regulatory organizations have the advantage of being able to coordinate state interests for providing regional recommendations to FERC. State oversight functions (*e.g.* siting, local outages, customer complaints) would not change. According to Nine Commissions, such regional regulatory organizations would provide greater coordination among states within the region, allowing for ADR processes that could satisfy multiple state jurisdictional requirements, and such organizations would monitor markets that have evolved beyond state borders and facilitate joint FERC and multi-state facilities siting.

Pennsylvania Commission prefers a joint Federal/state approach toward regulating RTO siting approvals, expansion, innovation and customer service. Pennsylvania Commission notes that a joint approach would resolve the vexing problem of Federal/state jurisdictional uncertainty and a joint Federal/state approach would avoid the potential for creative forum shopping by individual stakeholders, who will always seek to cast a dispute in jurisdictional terms so as to dictate a jurisdictional resolution to the perceived favorable outcome. A joint Federal/state approach has been used with success in other areas, such as the Susquehanna River Basin Commission, the Delaware River Basin Commission and the Joint Pipeline Office for the Trans-Alaska Pipeline System. Likewise, the Virginia Commission believes that there is no conflict between state goals and Commission goals and that the two levels of government should be able to work together and avoid conflict as long as both parties recognize that the common goal is the public interest.

Commission Conclusion. We continue to believe that states have important roles to play in RTO matters. For example, most states must approve a utility joining an RTO, and several states have required their utilities to turn over their transmission facilities to an independent transmission operator. Also, states must approve the siting of transmission facilities that are called for in an RTO expansion plan.

We believe, however, that it is not appropriate to try to set out a full set of states' roles in this Rule. It is difficult, and not necessary, to reach generic conclusions about states' roles given the diversity of possible RTO forms and state authorities. For example, a state's role may be different for an ISO, transco, and other organizational form, and it may be different for a multistate RTO and a single-state RTO, if any. States differ regarding the authorities they have vested in their regulatory and siting agencies. Further, states differ regarding their jurisdiction over municipal and cooperative utility owners of transmission facilities.

Regional interests forming an RTO should consult with the states about what state roles best fit the agencies' authorities and preferences and the organizational form of the RTO. This role could vary from state to state within an RTO. Therefore, this Rule takes a flexible approach that allows states to play appropriate roles in RTO matters, consistent with this Commission's exclusive responsibilities and authorities under the FPA.

We note that we have discussed the role of states for particular RTO functions elsewhere in this Final Rule. Regarding RTO formation, the Background discussion above discusses the role that several states played in creating many of the existing ISOs. It also describes our initial consultations with state regulators on RTO formation and our roles in FPA section 202(a) implementation; in those consultations we offered to continue the RTO dialogue with states in the future. The form of consultation to be used should be decided based on the issues and the region so we will not endorse or reject here any particular form of collaboration. However, in the Collaborative Process discussion below, we set out our plans to invite states and others to work with us to foster RTO formation beginning early next year.

In our discussion above of the Independence characteristic, we discuss the role of state agencies in governance, making the point that states will play a key role in RTO formation and development but declining to specify generically a state's role in governance. Also, in our discussion above of the RTO Planning and Expansion function we recognize the exclusive authority of state and local governments and regulatory agencies over the siting of transmission facilities, and we include in our regulations the standard that an RTO must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities.

8. Accounting Issues

Although not discussed in the NOPR, EEI commented on some accounting aspects of RTOs. It urges the Commission to address two primary accounting issues for RTOs: (1) The need to revise the Uniform System of Accounts (USofA) and related reports to reflect new RTO and other unbundled rate structures; and (2) the ability of RTOs to use regulatory accounting.

a. Revision of the Uniform System of Accounts

Comments. EEI contends that because the Commission's USofA was developed when utilities' products were bundled and fully regulated, it needs to be revised to support the Commission's adopted policies and this proposed rule. EEI believes that with unbundling of rates, the USofA will need to be revised to reflect, among other things,[718] cost functionalization (*e.g.,* by generation, transmission, distribution, etc.). EEI also believes that the Commission should specifically address the accounting to be used for RTO reporting purposes, as the current USofA was not designed for use by RTOs. EEI states that it is very willing to work with the Commission's staff to address the specific changes that should be made to the USofA.

Commission Conclusion. The Final Rule permits the various regions to select different organizational forms for RTOs. Our open architecture structure for RTOs permits applicants to select the business organization best suited to the needs of its members and RTO participants. It would therefore be difficult to prescribe in this proceeding specific changes to our existing USofA that would accommodate the needs of all RTOs.

We believe a better course at this juncture would be to require RTOs to conform their accounting to our USofA (as have ISOs) and to submit questions of doubtful interpretation to the Commission for individual or generic rulings on particular transactions, events and circumstances.

However, we agree with EEI's observation that unbundling of utility services, and other changes in the industry require the Commission to re-examine its existing accounting and related reporting requirements. This is true not only for the new types of utilities that have emerged in the industry such as ISOs, PXs and RTOs,

[718] Another significant area cited is whether the Commission should modify its original cost accounting requirements for property acquisitions to conform with the evolving fair value requirements of the Financial Accounting Standards Board (FASB). *See* Appendix I to EEI Comments at 11.

but also for traditional public utilities. The Commission staff has been and will continue to meet with EEI and others, and will continue its efforts to address the specific changes that may be needed as the industry restructures.

b. Ability to Use Special Accounting

Comments. EEI asks the Commission to consider the impact of its actions on the ability of RTOs to use the special accounting rules applicable to cost-based rate-regulated entities.[719] EEI believes that the ability to use regulated accounting would be advantageous to RTOs and viewed favorably by the investment community.[720] EEI urges the Commission to structure alternative ratemaking methods (*e.g.,* price and revenue caps, incentive-based rates and price indexing) to allow RTOs to continue to use the special accounting of SFAS 71. In this regard, EEI believes that if the Commission decides it is advantageous to stimulate the establishment of RTOs by ensuring that all start-up costs are ultimately recovered through FERC jurisdictional rates, it could issue ratemaking orders that defer expense recognition of these costs, and allow for future ratemaking recovery. Similarly, EEI urges the Commission to address the time frame over which software development costs could be recovered through rates and to allow utilities to defer expense recognition of such costs. To enhance cash flows from operations, EEI suggests that the Commission accelerate the amortization of all capitalized software costs. These actions, according to EEI, would likely be viewed favorably by the investment community.

Commission Conclusion. RTOs may propose and we are willing to consider alternative ratemaking methods including proposals to delay rate recovery of certain expenses. We will not prescribe any specific requirements at this time but allow RTOs to propose those methods which are appropriate for each RTO's facts and circumstances. In this regard, we intend to take a flexible regulatory approach toward approving RTO rate design proposals and strive to include adequate information in our rate orders on the appropriate accounting treatments.

9. Market Design Lessons

We expect that bid-based markets will be a central feature in many RTO proposals. To date, the Commission has analyzed and approved, with various modifications, bid-based market designs for four ISOs. The purpose of this section is to summarize the lessons learned from these real-world market experiments. The summary provided below is not intended to favor one market design over another, but is intended to assist RTOs in evaluating existing market designs and meeting the deadlines set forth in this rule.[721]

Cal ISO, PJM and ISO–NE have had operational experience with their respective market designs. For the most part the markets operated by these ISOs have functioned well, and they have not experienced many of the problems encountered in the bilateral markets in the Midwest and the Southeast.[722] However, each of the operational ISOs has encountered some market design problems that have resulted in unexpected or undesirable market outcomes.[723] These outcomes have led some ISOs to file many market design changes and requests for temporary remedies or protections until permanent design changes can be implemented.[724]

a. Multiple Product Markets

The bid-based markets that we have approved to date are premised on the assumption that acceptance of voluntary supply and demand bids which maximize overall net benefits will also maximize efficiency. Each approved ISO design employs some bid-based mechanism to ramp resources up and down to balance the system, manage congestion, and to supply some ancillary services. Employing bids that indicate a generator's willingness to be ramped down, ramped up, or placed in reserve is an economic way to balance the system, manage congestion and maintain appropriate reserves, both in real time and in any day-ahead markets. However, if more than one product is being sold in the same temporal market,[725] efficiency is maximized when arbitrage opportunities reflected in the bids are exhausted (*i.e.,* after the RTO's markets have cleared, no technically qualified market participant would have preferred to be in another of the RTO's markets). In addition, efficient bid-based markets elicit prices that are consistent with technical and cost requirements.[726] For example, a situation where generating units are paid more for not generating than for generating as has happened in ISO–NE and the Cal ISO may be an indication of an inefficient market.[727]

b. Physical Feasibility

Proper design of the market clearing procedures ensures that prices balance the supply and demand for energy, and all transactions, in the aggregate, are physically feasible with appropriate levels of reserves. Some market designs have allowed ISOs to accept schedules that have not been physically feasible (*e.g.,* Cal ISO), while other ISO market designs include mechanisms to ensure the physical feasibility of transactions (*e.g.,* the NY ISO and PJM). Some ISOs have encountered instances where transmission constraints have prevented the use of needed reserves,[728] and this is inconsistent with the operator's obligation to make certain that reserve requirements are met and that reserves, along with necessary transmission, are available to respond appropriately to contingencies.

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[719] The special accounting rules are primarily contained in Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71). One of the primary accounting differences is the ability to defer expense recognition of an incurred cost if it is probable that the utility will recover that cost in future cost-based regulated rates.

[720] Conversely, according to EEI, the inability of an entity to use SFAS 71 accounting could have an adverse effect on earnings, which may be viewed unfavorably by investors. According to EEI, one example would be where the Commission approves a rate levelization plan (*e.g.,* under capital lease transactions) under which rate recovery of certain costs would be deferred until future years. If a utility could not defer expense recognition of such costs, earnings would be depressed in the early years of the levelization plan.

[721] The Commission has already given considerable guidance on numerous market design issues in a number of orders. *See* Pennsylvania-New Jersey-Maryland Interconnection, L.L.C., 81 FERC ¶ 61,257 (1997); Central Hudson Gas & Electric Corp., *et al.* 86 FERC ¶ 61,062 (1999); New England Power Pool, *et al.* 87 FERC ¶ 61,045 (1999); AES Redondo Beach, *et al.,* 87 FERC] 61,208 (1999).

[722] *See* Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998 (September 28, 1998).

[723] The NY ISO has had little operational experience with the particulars of its markets design.

[724] *See* New England Power Pool, *et al.,* 87 FERC ¶ 61,055 (1999); AES Redondo Beach, *et al.,* 87 FERC 61,208 (1999); New York Independent System Operator, Inc. *et al.,* 88 FERC ¶ 61,228 (1999).

[725] For example, energy and operating reserve products may be offered in real-time.

[726] One would expect that services with more stringent technical requirements ordinarily have higher costs for providing those services. The prices of these services should reflect the costs. For example, spinning reserves have more stringent requirements and would be expected to command a higher price than non-spinning reserves.

[727] *See* Report of the Market Surveillance Committee of the California Independent System Operator, October 18, 1999 (MSC October Report). Both ISOs have seen prices for services such as non-spinning reserve products, which do not require a unit to be running, higher than the energy price. Also, according to the Market Surveillance Committee (MSC) of the Cal ISO, market participants have an incentive to submit schedules that will cause congestion so that their units can be called upon to relieve the congestion and receive payments for not generating that are greater than payments received for generating.

[728] *See* MSC October Report, at 67, 74–75.

c. Access to Real-Time Balancing Market

Real-time balancing refers to the moment-to-moment matching of loads and generation on a system-wide basis. Real-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) that increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator. Over the last several years, the Commission has seen an increasing use by system operators of market mechanisms that rely on bids from generators to achieve, overall, real-time balancing. In order to maintain system balance, the operator also manages congestion while maintaining the appropriate level of reserves. It is expected that any RTO balancing markets will be available to all grid users, *i.e.,* including individual grid users that engage in bilateral transactions. The fact that the overall system must be in balance moment-to-moment does not mean that there must be a moment-to-moment balance between the specific load and resources involved in individual bilateral transactions. Making a real-time balancing market available to all grid users ensures that all users are treated equally for purposes of settling their individual imbalances. The four operating ISOs approved by the Commission already operate such markets.

d. Market Participation

Markets are most efficient when generators and loads, whether internal or external to the RTO, are allowed full and flexible participation in the markets. While generators and loads have the option to choose between participating in any RTO-facilitated markets or other markets, the RTO must have generation and ancillary service quantity information, and any necessary technical information, from self-schedulers in order to balance the system and ensure reliability. This allows bilateral and forward financial markets and independent PX markets to co-exist and complement RTO physical markets. Participants that self-schedule would be expected to pay for the costs that they impose on the physical system at market prices and be paid for the benefits that they supply to the physical system at market prices.[729]

Unnecessary constraints on the imports of services can lead to increases in price volatility due to thin markets.[730] Allowing exports will give generators flexibility to take advantage of opportunities outside of the RTO boundaries, while allowing load serving entities external to the RTO a chance to purchase services. Broadening market participation deepens the market and enhances overall efficiency.

e. Demand-Side Bidding

Existing ISO markets offer generators flexible participation, but they often do not offer customers demand-side bidding options. Demand-side bidding is desirable to the extent it is technically feasible, because without it, demand response decreases and market power is easier to exercise.[731] The availability of price responsive demand also reduces price volatility in the markets.

f. Bidding Rules

A market that provides the flexibility for all generators to bid a reasonable approximation of the costs they incur including start-up, minimum load, energy, and ramping costs will be efficient. Whether it is cost-effective to start up a generator and make it available for dispatch depends on the prices and scheduled quantities over the multiple hours and services for which the generator is committed, not on the prices in any single hour or for any single service. Allowing participants to bid these costs helps provide for a more efficient dispatch of generating units to meet load and other services, because it allows the start-up decisions underlying the dispatch schedules to be based on prices and quantities for a period greater than a single hour. Not permitting start-up and minimum load bids can reduce efficiency because the decision to start up and dispatch generators is made separately for each hour, resulting in start up decisions that can cause losses for generators. Also, when the start-up and minimum load bids are submitted along with minimum run and down times, generators are ensured that they will not be dispatched in a way that is physically damaging to the unit.

g. Transaction Costs and Risk

Transaction costs associated with participation in well functioning RTO markets should be low, and market participation should involve no unnecessary risks. For example, in sequentially clearing markets, bidders are exposed to the risk that they may be chosen in one of the markets that clears first, yet would have preferred to have been chosen in a market that cleared later. In order to hedge against such risks, bidders may undertake expensive and time consuming bid preparation strategies to decrease the likelihood that such profitable opportunities would be missed.

h. Price Recalculations

In some instances, it may be necessary to post prices on a preliminary basis while the final price calculations are verified. For example, in ISO–NE, the computer algorithms generate new dispatch points every five minutes, and preliminary market clearing prices are based on these dispatch algorithms. However, the actual dispatch instructions are issued manually. In circumstances where time does not permit all changes in dispatch to be communicated and effected through manual processes in a timely manner, the market clearing price resulting from the computer algorithm must be adjusted to reflect the actual dispatch in the hour.[732] While an RTO must ensure that the final market clearing prices are correct, market clearing procedures should minimize price recalculations. Also, any price recalculation should be done quickly. Otherwise, market participants could incur large transaction costs in attempts to hedge against such risk. Risk exposure can be further reduced if market participants can engage in bilateral transactions, or participate in other markets, to lock in prices prior to participating in the RTO-facilitated markets.

i. Multi-Settlement Markets

Multi-settlement markets may involve a day-ahead and real-time market. For real-time markets, prices are determined by real-time dispatch quantities, and deviations from day-ahead schedules are priced at the real-time price. When day-ahead schedules are financially binding, they are financial commitments subject to payments for deviations at the real-time price. If market participants adhere to day-ahead schedules, they need not participate in the real-time markets. If needed for reliability, bids need to be physically binding and may be subject to Commission-approved penalties for failure to adhere to the bid. Without financially binding commitments in the day-ahead market, the riskiness of market participation

[729] Costs and benefits associated with self-schedules are congestion costs created by the transaction or congestion relief that the transaction makes possible.

[730] Thin markets refers to a situation in which the amount bid into the market is either not enough to match demand, or just enough to match demand.

[731] The flexibility of demand-side bidding may be limited unless real-time meters are installed. Otherwise, demand-side bidding can simply take the form of interruptible load.

[732] *See* ISO New England, Internal Review of Operations, June 7–8, 1999, Report issued August 20, 1999. Electronic dispatch is under consideration in ISO–NE.

increases since the day-ahead bids could be changed before real-time dispatch. If bids for ancillary services are accepted, the accepted capacity must be physically ready to meet reliability commitments when called upon. The lack of a physical capacity commitment has been a problem in some ISOs.

j. Preventing Abusive Market Power

An efficient market design does not favor market participants that have the potential to exercise market power and minimizes the incentives for market participants to engage in abuse of market power. For example, since large players are more likely to cause market power problems, a market design that favors large players (*e.g.,* portfolio bidding[733]) may create an incentive for consolidation and resulting market power problems. Fewer restrictions on imports of services will help guard against thin markets, which in turn will help mitigate market power. ISO's have experienced problems with thin markets, and easing restrictions on imports should help.[734] Also, artificially segmenting a product market into separate geographic markets for the same product can also create additional price volatility and opportunities for the exercise of market power.[735]

If market participants are allowed to submit bids which can then be changed before financial settlements are completed, these non-binding bids can be used as a signaling device to facilitate collusive behavior.

k. Market Information and Market Monitoring

One property of an efficient market has market clearing prices and quantities being made available immediately. This information enables market participants and potential future market participants to assess the market and plan their businesses efficiently. It will also allow market participants to spot errors in the market clearing process and get them corrected.

Disclosure of individual bids could be made eventually, but not immediately. Such disclosures will allow detection of market design and implementation flaws, and allow study of the market by independent analysts and market participants. It may lead to the exposure of the exercise of market power. To detect the withholding of capacity, a simple screen is to provide the output, reserve quantities, and maximum capacity of each generator. Immediate disclosure of individual bids is undesirable because it might facilitate collusion by the market participants. It also might affect the bids of market participants who wish to keep their costs confidential. However, after six months or a year, the information on individual bids has essentially no value for collusion and discloses little new information about any bidder's current costs. Nonetheless, the information's value for market monitoring remains high.[736]

l. Prices and Cost Averaging

Market designs that base prices on the averaging or socialization of costs,[737] may distort consumption, production, and investment decisions and ultimately lead to economically inefficient outcomes. Where possible and cost effective, cost causality principles can be used to price services and eliminate averaging.[738]

For example, in some congestion management mechanisms, the cost of alleviating congestion is spread over all loads. This scheme could have some generators creating monetary benefits for other generators. In addition, it could lead to over-consumption of power by some loads and under-consumption by other loads. Moreover, such averaging mechanisms for congestion management do not send the correct price signals for the location of new generation, thus leading to problems with long-term implications.[739]

Moreover, if pass-throughs or uplift charges are paid by all load to ensure bid-cost recovery, as in some approved ISO market designs, it may be appropriate to couple these pricing mechanisms with incentive mechanisms for the RTO to control them.

I. Collaborative Process

The Commission proposed a regional collaborative process to facilitate the creation of RTOs. State commissions had encouraged the Commission to sponsor activities in each region of the country that will bring together representatives of public and private electric utilities, state regulators, consumer groups, representatives from Canada or Mexico, as appropriate, and any other interested parties that need to be part of such a process. The Commission proposed that regional workshops be held after the Final Rule is issued to determine what, if any, impediments exist to the formation of RTOs in a particular region and how the Commission staff could help to overcome those impediments. Staff resources that will be available for the collaborative process include technical staff, dispute resolution staff, and any other staff assistance that would be beneficial.

Comments. Almost all commenters support the Commission's collaborative proposal. Of the 49 comments that addressed this issue, 47 are generally supportive. These commenters include a number of state commissions.[740] In addition, NARUC supports the continuation of a ''dynamic process requiring continuing dialogue between FERC and the states.'' A number of public power entities also support the process.[741] Numerous Canadian entities also filed comments regarding the usefulness of a collaborative process for the international aspects of RTO formation.[742]

Only Florida Commission and CP&L are not fully supportive. Florida Commission suggests that FERC collaboration will not work in Florida but may work in other regions of the country. CP&L is not supportive because the collaborative process could be used by the Commission ''as a means of forcing utilities to develop RTO proposals on the Commission's timetable'' which results in the Commission ''being disingenuous when it describes its RTO policy as 'voluntary'.'' Otherwise, CP&L believes the conferences will only serve as an opportunity for participants to ''posture'' and that limited Commission resources should not be used for

[733] Portfolio bidding refers to bids that aggregate all generating units under the same ownership. This is in contrast to generation owners bidding in each unit separately.

[734] Report of the Market Surveillance Committee of the California Independent System Operator, August 19, 1998 at 35–36 (MSC August Report).

[735] The Cal ISO at one time segmented their product markets into separate geographic markets that corresponded to the defined congestion zones even when no congestion existed. It has since reformed this practice. *See* MSC August Report, at 32–33.

[736] The Commission approved the disclosure of bid information in the following orders. *See* PJM Interconnection, L.L.C., 86 FERC ¶ 61,247 at 61,890, *order on reh'g,* 88 FERC ¶ 61,274 (1999); Central Hudson Gas & Electric Corp. *et al.* 86 FERC ¶ 61,062 at 61,204, *order on reh'g,* 88 FERC ¶ 61,138 (1999).

[737] Socialization of costs means that costs that could be assigned to a particular market participant(s) are instead spread over all participants regardless of whether or not they caused the costs.

[738] While it is desirable from an efficiency standpoint to eliminate the averaging of costs, the costs associated with calculating cost causation in some instances could be shown to outweigh the benefits of eliminating averaging.

[739] MSC October Report, at 112.

[740] *See, e.g.,* Nine Commissions, Illinois Commission, Indiana Commission, Michigan Commission, Montana Commission, Nevada Commission, South Carolina Commission, Wisconsin Commission and Wyoming Commission.

[741] *See, e.g.,* APPA, NRECA, CMUA, SRP, Snohomish, Seattle, RUS, East Texas Cooperatives, IMEA, and Arkansas Cities.

[742] *See, e.g.,* Powerex, BC Hydro and Canada DNR.

meetings that ''are not likely to produce positive results.''

Specific comments about the collaborative process address three basic issues: inclusiveness, process and procedures, and outcomes.

Inclusiveness. The NOPR stated that ''the Commission expects public utilities and non-public utilities, in coordination with appropriate state officials, and affected interest groups in a region to fully participate in working to develop an RTO.'' It further stated that the regional public workshops will be convened in cooperation with the affected state officials and that transmission owners and operators will be invited.

Many commenters advocate an open collaborative process that would include a full complement of participants. They suggest that the regional meetings include representatives of all stakeholders, for-profit transmission companies, not-for-profit transmission entities, state regulators, state legislators, state Governors, state energy officials, state and non-state consumer advocates, state economic and environmental regulators, environmental action interests and public power/municipals. Some commenters indicate that in certain regional efforts to form an RTO, the deliberations have excluded key interests and, as a result, the outcomes were not widely supported. For example, PJM/NEPOOL Customers note with respect to the PJM formation process that ''[O]nly after all stakeholders were included in organizational discussions was true progress made toward implementing an ISO that adequately addresses all parties' needs.'' PNGC states that ''[I]f other users do not have a seat at the table while merchant functions do, obviously a level playing field is not created.'' New Orleans cites Entergy's ''failure to even attempt to build a regional consensus concerning its transco as a reason that inclusive regional conferences are needed.''

Process and Procedures. Commenters raise a number of questions regarding the collaborative process and specifically with respect to the regional public workshops. Many commenters support the use/availability of the Commission's Dispute Resolution Service (DRS) staff or the use of outside facilitators. Some commenters request that the Commission clarify that the meetings will be open meetings that can be attended by any person. Several commenters urge the Commission to take the cost and travel time to attend meetings into account in planning the regional public workshops. Some specific locations are suggested for sites for the regional workshops: New Orleans, Minneapolis/St. Paul, and Seattle or Portland.

Several commenters suggest that the collaborative process begin prior to spring 2000 in at least one region of the country—the Upper Midwest. Commenters suggest that there is no need to wait and that the region would benefit by immediate assistance from Commission staff as described in the NOPR.

Some commenters ask the Commission to be mindful that the number of regional meetings scheduled may not only be costly but unproductive as well. Two commenters specifically say that we must not allow the ''death by meetings'' syndrome to be realized. Some interests may want to stall RTO formation by promoting an ''endless'' series of meetings that are not productive but are designed to ''preserve the status quo.'' A few commenters suggest that the role of Commission staff at the regional events should not be that of meeting referee but primarily to provide policy guidance on key RTO issues and proposals. NRECA proposes the creation of several Commission staff teams to ''facilitate and informally monitor each RTO formation process'' and provide ''neutral guidance'' in the regions. Some commenters ask that the Commission establish procedural rules in writing in advance of the regional workshops so that all parties will know and understand the rules prior to the meetings. Some commenters also request that all reports, information and data produced for the meetings be readily available to all participants.

Outcomes. The Project Groups suggest that the Commission should ''clearly delineate the substantive results expected'' from the collaborative process. They suggest that collaboration progress reports be filed with the Commission and that ''work products'' be required, including: (1) Identification of RTO boundaries; (2) a list of all transmission owners and facilities in the region; (3) a draft operating agreement; (4) a draft governance structure and bylaws; (5) proposed operating protocols; (6) a proposed budget/financial structure; (7) a draft tariff; and (8) how the proposals meet the Commission's guidelines, including a timetable.

Commission Conclusion. A key element of this Final Rule is our commitment to the use of the collaborative process to assist in the voluntary formation of RTOs. By collaborative process, we mean a process whereby transmission owners, market participants, interest groups, and governmental officials can attempt to reach mutual agreement on how best to establish RTOs in their respective regions. We reiterate our commitment of Commission staff resources, to the extent possible, to assist parties in developing RTO proposals.

We are encouraged that state Commissions, public utilities, public power entities and cooperative utilities, power marketing interests, and consumer and environmental groups support the use of a collaborative process. We are further encouraged that efforts to develop RTOs continue in the West and Midwest, and that other areas are reviewing the potential benefits of RTOs in their respective areas. We believe that this represents a growing recognition throughout the nation that RTOs will improve competition in electric markets and enhance the reliability of the nation's electric grid.

We welcome participation in the RTO collaborative process by our sovereign neighbors, Canada and Mexico. We believe that it is in our mutual best interest to have electricity flow efficiently and economically across our international boundaries. We pledge to continue to work cooperatively with officials from Canada and Mexico to encourage the operation and improvement of an international electric system that benefits all consumers.

The Commission believes that the collaborative process must accommodate the fact that different regions of the country are in different stages of RTO formation and must be flexible enough to allow for these differences. Therefore, we will initiate the collaborative process with a series of five workshops in the Spring of 2000. The primary objective of each workshop will be to develop a consensus agreement by regional participants establishing a strategic process and a schedule for any further collaboration. The appropriate collaboration process will depend on whether the region is considering formation of an ISO, transco, or other form of RTO. To achieve this objective, participants will share information about the status of RTOs or RTO proposals in the region, identify impediments to RTO formation in the area, explore which process(es) could most expeditiously advance agreements on RTO formation, and determine what role(s), if any, Commission staff should play in advancing discussions in each region. One result of these discussions may be regional decisions that more than one RTO would be appropriate in the area encompassed by participants at the workshop. Therefore, the collaborative processes that follow the various workshops may differ significantly. This includes possible variations in the role that will be played by Commission staff in each RTO formation effort.

The Commission believes that regional workshops in the Spring of 2000 will expedite the RTO formation process. In selecting locations for the initial Spring 2000 workshops, we recognize trends in the broader regionalization of the nation's electric system. We also consider the evolving electric markets as well as the configuration of the regional grid. We emphasize that the selection of locations for initial workshops is not to indicate a preference for specific RTO boundaries, but to provide convenient workshop locations. With these considerations in mind, we designate the following workshop locations. Parties may attend more than one regional workshop. We expect all transmission owners to attend at least one workshop.

Workshops will be held in the following cities in February, March or April, 2000:

1. Philadelphia, Pennsylvania
2. Cincinnati, Ohio
3. Atlanta, Georgia
4. Kansas City, Missouri
5. Las Vegas, Nevada

Workshops are expected to last for two days. Additional information about the regional workshops will be provided in January 2000.

At the request of parties, the Commission staff may play a role in the formation of RTOs. Commission staff will convene the regional RTO workshops and provide policy and technical guidance consistent with this rule. The Commission will supply meeting space for the five initial Spring 2000 workshops. Regional participants are expected to bear the costs of collaborative meetings after the initial five workshops. Commission staff time and staff travel expenses will be provided as resources allow.

We believe that it is critical to make the Spring 2000 Workshop phase of the collaborative process open to all interested parties. In order to promote an open process, we will provide public notice of Spring 2000 Workshop events to allow all interested parties to attend. We shall also make available agendas and procedural rules to all parties in advance of the regional workshops. Agendas may vary from one workshop to another.

The Spring 2000 Workshops represent the initial step of the collaborative process. We expect that other meetings will be convened following the workshops by parties in each region to bring the parties together to form an RTO in each region. Commission staff may also convene additional meetings if this would help RTO formation. The post-workshop meetings of parties in regions may be held with or without Commission staff participation. We will make available the Commission's Alternative Dispute Resolution staff upon the request of an RTO group in formation. At the request of such a group, independent private professional facilitation services may be arranged by Commission staff and must be sponsored by the parties within the region. As needed and requested by parties forming an RTO in a region, Commission staff members will be available to act as settlement judges, mediators, facilitators or observers.

We believe that the best interests of the nation's electric consumers will be served by the formation of RTOs. Therefore, we encourage parties to establish strategic schedules at the Spring 2000 Workshops and to convene subsequent meetings with the goal of forming an RTO expeditiously. Commission staff will monitor progress with respect to the results or outcomes in each region.

We expect that, following the initial Commission-sponsored workshops, parties in each region will work collaboratively to identify the appropriate RTO regions, identify all transmission owners and facilities in each region, and develop a timely application in accordance with the Final Rule.

We have designated James Apperson of the Commission Staff to serve as the collaborative process contact. He may be contacted at (202) 219–2962 with any questions or comments about the RTO collaborative process.

J. Implementation Issues

1. Filing Requirements

In the NOPR, the Commission proposed that all public utilities that own, operate or control interstate transmission facilities (except those already participating in a regional transmission entity in conformance with the eleven ISO principles enumerated in Order No. 888) must file with the Commission by October 15, 2000 either (1) a proposal to participate in an RTO that will be operational no later than December 15, 2001, or (2) an alternative filing describing efforts to participate in an RTO, obstacles to RTO participation, and any plans and timetable for future efforts.[743] For those public utilities that file an RTO proposal on or before October 15, 2000, we proposed to permit them to file a petition for a declaratory order asking whether a proposed transmission entity that would be operational by December 15, 2001, would qualify as an RTO, with a description of the organization and operational structure, a list of the intended participants of the institution, an explanation of how the institution would satisfy each of the RTO minimum characteristics and functions, and a commitment to submit necessary FPA section 203, 205 and 206 filings promptly after receiving the Commission's determination on the declaratory order petition. Finally, we proposed that the requirements not apply to a public utility that owns, operates or controls transmission that also is a member of an existing transmission entity that the Commission has found to be in conformance with the Order No. 888 eleven ISO principles; instead, each such public utility would be required to make a filing no later than January 15, 2001, that (1) explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions of an RTO; (2) proposes to modify the existing institution to become an RTO; or (3) explain efforts, obstacles and plans with respect to conforming to these characteristics and functions.

Comments. Most commenters responding on this issue oppose one or more aspects of the proposed filing requirements. For example, a number of public utilities and two state commissions argue that the October 15, 2000, filing requirement does not provide enough time. Southern Company contends that the proposed filing deadline requirement is likely to be counterproductive because it imposes an artificial deadline that may interfere with regional discussions. Moreover, once established, a prematurely formed RTO may itself prove to be an obstacle to more effective transmission organizations. Southern Company also claims that the proposed mandatory filing requirements are inconsistent with a truly voluntary approach. If the requirement is retained, Southern Company suggests that the Commission clarify that the alternative filings will be treated as status reports and not be subject to deficiency orders or otherwise lead to proceedings in which punitive measures might be taken, because any consideration or use of penalties seriously undermines the Commission commitment to the voluntary nature of RTOs.

Wyoming Commission recommends that the deadlines not be made

[743] FERC Stats. & Regs ¶ 32,541 at 33,761–63.

mandatory in any way in the Final Rule because RTO formation is supposed to be voluntary. Since it is unclear as to what happens to those entities who file an explanation as to why they did not join an RTO, Wyoming Commission urges the Commission to defer to each region's process and timetable in developing an RTO and acknowledge that not all regions are processing at the same pace. It recommends that the Commission convert the October 15, 2000, deadline into a milepost for reporting RTO development.

CP&L submits that the time frame is unrealistic because it contemplates that new RTOs can be developed, approved by the Commission, set up, and begin operation in less than two years. Experience has shown that almost every RTO to date has taken at least four years to go through that process. Therefore, the Commission should modify the filing requirements to simply require informational filings on the status of RTO development.

Sierra Pacific is concerned about insufficient time being allowed for transcos to form. It points out that the precedent regarding ISOs is much more well-developed than that regarding transcos. The certainty surrounding ISOs makes them more attractive particularly when a decision to form the entity must be made relatively quickly to meet the proposed October 15, 2000, filing date. To lessen the incentive to rush to join an ISO, Sierra Pacific suggests that: (1) The date for filing an RTO proposal should be extended to June 15, 2002; (2) the Commission permit transition mechanisms that will allow transmission owners to eventually join transcos; and (3) the Commission not require participation in an ISO to become a trap from which a transmission owner cannot extricate itself. ComEd provides supporting arguments, noting that where divestiture of transmission assets is involved to form transcos, the necessary transition period will largely be dictated by the sheer complexity—legal, financial (bonds and mortgage), real estate (titles/easements), taxation—of separating a designated portion of any electric utility that has historically been a vertically integrated utility.

Based on its experience with the Midwest ISO formation process, Kentucky Commission also argues that the proposed date to join an RTO or respond with reasons for not joining is too short. It points out that, if the Commission completes the Final Rule by the end of 1999, transmission owners will have less than one year to make a final decision on participation. Kentucky Commission urges the Commission to give transmission owning utilities additional time to look into joining an RTO, so that RTOs are not pushed so quickly that the best model fails to materialize as a result of market evolution that remains underway. South Carolina Commission and Big Rivers share the concern that the proposed timeframe is too ambitious, given the complexity of RTO related matters and the need to reach some level of consensus among those with vested interests.

Several commenters noted that meeting the October 15, 2000, filing requirement will depend on the Commission's standard of review of those filings. For example, TDU Systems observes that the proposed filing requirements have no teeth. TDU Systems contends that a public utility that decides not to participate in an RTO can make an alternative filing setting out the reasons why it is not doing so and what plans it has to work towards participation. In TDU Systems' view, while the proposed regulations are consistent with voluntary participation, they are inconsistent with full and effective participation in RTOs. TDU Systems counsels that the Commission should resist calls to water down the RTO regulations even more, so as to treat alternative filings as mere status reports that allow transmission monopolists to hold on to their monopolies.

Duke submits that if the Commission is willing to accept valid, well-justified explanations as to why a utility has not become an RTO member, the October 15, 2000, filing requirement is reasonable, noting that until state commission review of restructuring and RTOs is completed, it may be premature for a utility to commit resources to RTO membership. Similarly, Iowa Board suggests that, where transmission providers are making legitimate progress, a report to that effect should not be received with automatic disfavor. Alternative filings and legitimate progress reports should be given equal validity with definitive proposal filings.

A few commenters explicitly support the October 15, 2000, filing requirements. For example, SRP believes it to be an acceptable balance between mandated participation and the status quo. PJM/NEPOOL Customers also support the filing by a date certain because this would expedite the collaborative process and ensure that no entity can effectively block RTO formation by engaging in inappropriate negotiation tactics. And Oglethorpe views the October 15, 2000, time frame as necessary to assure the timely development of RTOs and help develop fully competitive efficient wholesale markets. Cinergy, noting that only after the Commission has had opportunity to review the October 15, 2000, filings will it be able to determine whether it should order participation in or reconfiguration of particular RTOs, suggests that by April 15, 2000, all public utilities be required to file a statement of position in which each utility identifies each state in which it owns transmission, and the RTO in which it is considering membership and its potential scope and configuration to the best of its knowledge.

A number of commenters address issues and treatments relating to existing ISOs. Virtually all of the existing ISOs assert that the Commission should allow the previously Approved ISOs to continue to develop without undue interference in order to foster experimentation and testing of proposals.[744] Cal ISO argues that the Commission should find that existing regional entities generally meet the RTO criteria and that the Commission should confirm its determination not to require substantial changes in approved ISOs that would undermine difficult to reach consensus on critical issues. Similarly, the Pennsylvania and New York Commissions recommend that FERC grandfather the existing ISOs that meet the RTO characteristics and functions. The Pennsylvania Commission states that it does not want to tinker with the inner workings of PJM, nor constantly revisit and revise operations and functions. The New York Commission is concerned that the New York ISO tariff may have to incorporate the ''ordinary negligence'' liability and indemnification provisions set forth in the pro forma tariff if the ISO becomes qualified as an RTO, and that this will increase the ISO's exposure to litigation. The South Carolina Commission supports NARUC's position urging the Commission to grandfather existing ISO boundaries that are satisfactory to the states. Similarly American Forest, CalPX and Mid-Atlantic Commissions want the Commission to respect existing ISOs.

Furthermore, PJM/NEPOOL Customers contend that their ISOs are in basic conformance with the minimum functions and characteristics. To the extent that any deficiencies are found, the ISOs should be allowed to engage in continued experimentation without interference from the Commission. The Wyoming Commission also fails to see why existing ISOs, already having gone through a rigorous approval process, should have to re-certify as RTOs.

[744] *See, e.g.,* NY ISO, Cal ISO, NYPP and ISO–NE.

Moreover, EEI notes that the Commission should weigh the incremental gains achieved through economies of scale, efficiency, and additional savings against the potential incremental costs of reorganization, new computer programming, infrastructure changes, and changes required to achieve effective communication and coordination. NYPP proposes that ISOs be allowed to evaluate the costs and benefits of forming an RTO after some years of market experience; hence, they oppose putting members of existing ISOs on the same time frame for compliance as non-members of ISOs/RTOs. United Illuminating recommends that the Commission continue to honor and not abrogate pricing arrangements of existing ISOs. United Illuminating also contends that, since existing ISO members have no opportunity to discriminate because they have turned control of their transmission over to their respective ISO, the Commission cannot generically abrogate existing ISO pricing arrangements pursuant to its FPA section 206 authority in this rulemaking. Central Maine offers that consolidating the PJM, New England and New York ISOs into a super-ISO will require costly expansion of telemetry, communication, and computer equipment, that it could result in a decrease in reliability, and that simple interregional coordination could accomplish the Commission's goals without consolidation.

A few non-ISO entities oppose any grandfathering of existing regional transmission organizations.[745] For example, New Orleans argues that the Commission should not exempt existing regional transmission entities from requirements of RTO formation because only through universal application will all regions of the country receive the benefits of open and competitive electric markets. H.Q. Energy Services suggests that a larger territory, such as the combined territory served by the existing New York, PJM and New England ISOs, would be more effective than the NY ISO standing alone. PG&E counsels that freezing the existing ISO structures in place would not serve reliability or the marketplace and would be inconsistent with the open architecture requirement. It believes that the Commission has struck an appropriate balance imposing a reporting requirement on existing ISOs.

Most commenters agree that existing operational transmission entities should gradually evolve toward RTOs during a transition period, rather than making immediate and drastic changes.[746] According to SMUD, a transition period will enable customers to avoid bearing unnecessary costs.

A few commenters address the specific filing requirements outlined in the NOPR. The New York Commission asserts that the NY ISO should not have to make a filing because it possesses the requirements of an RTO. In addition, the Cal ISO argues that existing entities, rather than individual public utilities, should be responsible for the RTO filing requirements. Likewise, PJM suggests that existing ISOs report to the Commission prior to any report by its public utility members, as the existing ISO is in a better position to provide the Commission with the most accurate information by which to evaluate whether the ISO satisfies the minimum characteristics and functions for RTOs. PJM suggests that existing ISOs and existing transmission entities file reports no later than December 31, 2000, explaining whether they satisfy the Commission's requirements for RTOs and identifying any additional authority they may require for this purpose. On the other hand, EPSA welcomes the proposal requiring a showing of how the existing transmission institutions meet the minimum characteristics and functions by January 15, 2001, as a way to help address and solve continuing discrimination within current ISOs and address whether these institutions should be combined into larger groupings. Similarly, NYC wants the NY ISO's January 15, 2001, filing to demonstrate how its efforts to improve regional cooperation will overcome the institutional impediments that have contributed to the city's load pocket condition.

Finally, commenters raise a number of miscellaneous issues: Puget questions whether there will be negative implications for any entity the choose to cease participation in an RTO; DOE points out that RTOs may need to fund pensions for transferred employees, and existing transmission providers may need to fund early retirements or other compensation for displaced employees; UMPA recommends that recourse to the Commission in a *de novo* capacity must be part of all RTO dispute resolution procedures; and Indiana Commission, Snohomish and Midwest ISO express concern about how the Commission intends to handle multiple RTO proposals covering approximately the same region.

Commission Conclusion. The Commission will adopt the NOPR proposal requiring that all public utilities that own, operate or control interstate transmission facilities (except those already participating in an approved regional transmission entity) file by October 15, 2000, either a proposal to participate in an RTO or an alternative filing describing efforts and plans to participate in an RTO. As proposed initially, we will consider a petition for declaratory order setting forth the items listed in section 35.34(d)(3) as a proposal to participate in an RTO.

We believe that the October 15, 2000, date for filing proposals is realistic. It is not overly aggressive, given the amount of guidance we have provided in this Rule and the amount of flexibility we are permitting in how to satisfy the minimum characteristics and functions. In addition, the collaborative process that we are promoting in this Rule will provide an opportunity for all interested parties with their varied interests to resolve many of their differences, in advance, and reach consensus on the RTO solution that best fits the overall needs of their respective region. The October 15, 2000, filing date should help keep the parties focused and accelerate their efforts toward selecting an appropriate RTO model.

The October 15, 2000, date for filing is also reasonable because, even if a public utility is unable to file an RTO proposal at that time, we are permitting the public utility to make an alternative filing reporting on the status of pertinent RTO formation and development, the obstacles that have prevented the filing of an appropriate RTO proposal, and any of the public utility's plans and timetable for future efforts directed toward RTO formation and participation.[747] Given the importance that the Commission places on RTO development, it is important for us to understand no later than October 15, 2000 just how much progress the industry is making on forming RTOs. If the October 15, 2000, filings reveal obstacles that prevent serious progress toward RTO formation are reported for a given region, we will be able to act early enough to provide guidance on what steps we think are appropriate to help address the obstacles (*e.g.*, further collaborative efforts). And where serious regional progress is reported, but more time is requested in connection with meeting a particular RTO requirement, we will be able to act early enough to try to accommodate the local needs,

[745] *E.g.,* Illinois Commission, New Orleans, SMUD and Turlock.

[746] *See, e.g.,* SMUD, PJM/NEPOOL Customers, NYPP, Cal DWR, MEAG, American Forest and Central Maine.

[747] Of course, these reports may be filed prior to October 15, 2000.

complications and complexities that the particular region faces.

Some concern has been expressed that the October 15, 2000, filing date is too short to allow transcos to form because of the inherent legal, financial, real estate and taxation complexities associated with the transfer of ownership of the affected transmission assets. We are not proposing that the restructuring be completed by October 15, only that a proposal be filed, or an alternative filing as described in this Rule. Moreover, we take note of the fact that other forms of major corporate restructuring, including mergers, have proceeded from initial idea to formal proposal in a shorter time when the motivation is sufficient. Therefore, we do not think the time allowed is too short for transco proposals.

We also reaffirm the proposed January 15, 2001, filing date for transmitting public utility members of an existing approved transmission entity to address the extent to which that entity conforms to the minimum characteristics and functions of an RTO, any plans to make it conform, and any obstacles to full conformance with our Final Rule. We note that RTOs will not be ''starting from scratch.'' There is significant information available about both the good and bad experiences with ISOs, and this information should help RTOs meet this filing deadline.

While we are allowing a later filing date for existing transmission institutions to file (January 15, 2001, versus October 15, 2000), we do this because, in general, the transmission owners in those regions have already made substantial progress in establishing regional entities. Nonetheless, the Commission needs to know, for all regions, including those covered by existing approved transmission institutions, the extent of progress toward formation of fully functional RTOs. To the extent that an existing ISO, for example, is less than adequate with regard to one of the necessary characteristics or functions, we would expect the existing institution to be working on a plan of action to make the remedial improvements that are required to bring it into conformance with the Final Rule.

In sum, we continue to believe that the October 15, 2000, and January 15, 2001, filing dates represent an acceptable balance between the need to move toward RTOs as soon at possible and the need for sufficient time for transmission owners and market participants to develop proposals.

2. Deadline for RTO Operation

The Commission proposed that all public utilities participate in an RTO that will be operational by December 15, 2001. In addition, we contemplated implementation of the congestion management function within one year after startup (by December 15, 2002), and implementation of inter-regional parallel path flow coordination and transmission planning and expansion functions within three years after startup (by December 15, 2004).

Comments. Most commenters suggest the December 15, 2001, deadline should be changed to a later date or that the Commission provide greater flexibility in meeting the deadline. On the other hand, Oregon Commission explicitly favors the December 15, 2001, deadline, arguing that the time line is designed in stages so that the easiest requirements come earliest. EPSA fears that further delay of any of the operational deadlines for any of the required RTO functions (*i.e.*, for initial startup, congestion management, parallel path flow coordination, or transmission planning and expansion) will only encourage further debate and dialogue without driving the industry towards acceptable resolutions, and prolong the problems of residual discrimination and remaining market inefficiencies.

Two commenters propose an earlier deadline. PG&E contends that the transition period for RTOs to meet all requirements must be as short as possible—no more than one or two years to fully operational RTOs may be reasonable. Sithe similarly argues that, while the negotiations and proceedings associated with voluntarily RTOs can take years to complete, the California experience suggests that an RTO can be established quickly if a deadline exists. Sithe recommends that the Commission reconsider its time frame and do everything it can to hasten the process of putting in place RTOs with all minimum characteristics and functions. It observes that, as proposed in the NOPR, an RTO could defer for up to three years the filing of a plan for transmission planning and grid expansion. The details may not be finally approved by the Commission for at least another year such that a delay of over five years could result.

SRP and American Forest express concern about who will be responsible for building and paying for new transmission facilities until the RTO takes on this responsibility. In particular, SRP suggests that the Commission require each RTO filing to describe who will be responsible for financing and building transmission expansions during the interim.

Most commenters, however, view the proposed deadline as too aggressive, and recommend that it be eliminated or extended. CP&L views the operating deadline as arbitrary and capricious, and argues that the deadline will impose higher implementation costs and inefficiency that will not benefit the public or the industry. South Carolina Authority believes that to assume that a large group of stakeholders with diverse interests can somehow come together and agree on a particular RTO model and configuration by October 15, 2000 that is up and running by December 31, 2001, is unrealistic. East Kentucky suggests that the timetable be extended approximately two years. Montana Power encourages extension by one year because areas like the Pacific Northwest will probably need significant infrastructure to be developed or re-deployed and the 14 month time frame contemplated after RTO proposals are due on October 15, 2000, is not sufficient time.

A number of commenters favor a flexible approach and allowing provisional RTO status. Cinergy offers that, to overcome obstacles such as legal impediments to public power participation, alternative means of RTO participation be considered such as joint operations without the functional integration of public systems' facilities to allow them to control the private use of their systems. SERC generally concurs. Williams contends that not all RTOs will be able to develop at the same pace, and supports provisional RTO status with dates certain respecting those functions not able to be performed at startup.[748] SNWA recommends that, if necessary, a phase-in approach should be used in the implementation of an RTO to smooth the implementation process. Project Groups contends that, given the California experience, the cost of attempting to do everything at once is significant. Transmission ISO Participants urges flexibility for transmission owning members of exiting ISOs since the current structure represents an imperfect and probably unfinished agenda. EEI contends that the Commission should allow flexible timetables to establish RTOs that are transcos, contending that a vertically integrated utility that selects the option of moving transmission assets to a transco faces complex financial and tax issues. Nevada Commission urges the

[748] Note that a number of comments opposing deadlines are based on the difficulty of attaining specific RTO functions. These comments are also addressed in the sections regarding the specific functions.

Commission to clarify that there is no prohibition against forming interim organizations such as an independent system administrator until such time as a viable RTO for the region is formed. South Carolina Commission claims that each RTO proposal should be reviewed on a case-by-case basis for general adherence to the Commission's overall policy goals.

Indiana Commission cautions, however, that careful consideration should be given to what will be lost by the acceptance of an RTO ''lite.'' It argues that existing transmission entities may see little value in maintaining relatively high standards and could view the Commission acceptance of lower standards as an incentive to gravitate to lower standards. PG&E recommends the Commission grant waivers from its requirements only in limited cases and only for short durations. AEPCO, contends that there should be a reasonable basis for granting waivers, particularly for non-jurisdictional entities. In particular, a request for waiver should consider: (1) How much additional RTO transmission would result from inclusion of the facilities in an RTO; and (2) whether the RTO would be functional without inclusion of the entity's facilities. Sithe argues that care should be taken when considering whether to permit RTOs to go into effect without meeting functions and in granting waivers, and suggests that the Commission establish clear requirements for RTO approval, strictly scrutinize proposals, and not hesitate to reject inadequate proposals.

Commission Conclusion. We have decided to retain the originally proposed startup and other functional implementation deadlines (RTO startup by December 15, 2001, implementation of congestion management by December 15, 2002, and implementation of the parallel path flow coordination and transmission planning and expansion functions by December 15, 2004).

As a general proposition, we believe that, given the urgent needs of electricity markets as discussed elsewhere in our Final Rule, we have an obligation to promote RTO operation at the earliest feasible date. Even where a market may already be served by an ISO or other approved transmission entity, we are concerned that such market may remain hampered to the extent that the approved entity has yet to fully conform with our Final Rule.

In response to those who contend that December 15, 2001, is too ambitious for RTO start-up, we note several points. First, we, and the industry, now have had the benefit of the experience of the formation of five ISOs under Commission jurisdiction, an ISO in ERCOT, some international experience with regional transmission entities, and substantial discussion of the subject of regional transmission entities within the industry. While the timeframe we are suggesting for RTO formation may have been unrealistic several years ago, much has been learned since then which should facilitate more rapid formation.

Second, our Final Rule is providing substantial flexibility that should permit an RTO to satisfy the minimum characteristics and functions in a cost efficient manner. For example, we are not requiring control area consolidation; we are not requiring the establishment of a PX; we are allowing an RTO to meet its operational control obligation through indirect or hierarchical control arrangements via contractual agreements with the existing infrastructure such as transmission owners and control area operators; and we are allowing an RTO to satisfy its security coordinator functions through contractual arrangements with an external security coordinator, as long as it is independent. An acceptable RTO structure need not be a monolithic organization that requires an extended period of time to become fully set up so that it can directly ''push all of the buttons.'' Moreover, we are allowing a longer phase-in period for functions that may be more difficult to establish, such as congestion management, parallel path flow measures, and transmission planning and expansion.

With respect to the comments that question the December 15, 2002, deadline for implementing the congestion management function, we believe that lack of effective and market-oriented congestion management is a critical issue in the industry, and that it needs attention soon. We acknowledge that developing a sophisticated congestion management program can be an extremely complex and time consuming matter. However, implementation of economic approaches to congestion management by some of the approved ISOs shows the feasibility of these concepts where there is an institution to undertake the organization of this function over a large area.

Some say that transmission congestion is not a serious problem in their regions, and that they therefore should not be required to develop a complex congestion management plan within a short time-frame. We agree that an RTO should not have to expend large resources to address a problem that does not exist. However, we are concerned that an RTO fully analyze the extent to which transmission congestion does or could interfere with electricity sales in its region, and that it be prepared to address congestion if it becomes a more serious problem through changing markets. As markets become more competitive and the volume of discrete transaction increases, transmission congestion may become serious unless action is undertaken beforehand. Where transmission congestion is infrequent, this Rule does not preclude the establishment of relatively less complex forms of market-compatible congestion management such as generation redispatch protocols.

In sum, we think that the phased startup and other functional implementation deadlines are reasonable.

3. Commission Processing Procedures

The Commission recognized that RTO formation would be complicated by the requirements for Commission approval of transfer of control of jurisdictional facilities under FPA section 203 and Commission approval of RTO transmission rates, terms and conditions under FPA section 205. In the NOPR, the Commission requested comments on whether the Commission should provide expedited or streamlined processing procedures for RTO filings and asked for suggestions regarding how the Commission can further expedite and streamline procedures.[749]

Comments. Views on streamlined and expedited processing of RTO filings are mixed. Commenters that generally favor streamlining include Desert STAR and TEP, which suggests that filing requirements be kept simple and flexible.

A number of commenters offer specific suggestions for streamlining and expediting the process, including:

• Florida Commission believes that once an RTO or other structure has been agreed upon by a group of entities, the Commission should expedite all required processes in order to allow the participants to start implementing the agreed upon changes.

• Tallahassee recommends that the Commission should clarify that it is not revisiting the functional test for distinguishing transmission and distribution facilities addressed in Order No. 888.

• Entergy asserts that significant delay in obtaining Commission approvals will make it difficult for Entergy to institute a transco within the time-lines established by state restructuring laws in Arkansas and Texas. Providing clear rules on the

[749] FERC Stats. and Regs. ¶ 32,541 at 33,759.

required and permissible features of RTOs as the Commission did in its July 30, 1999 Declaratory Order for Entergy and providing clear standards on pricing policies will help. Entergy argues that the Commission should make explicit its willingness to consider requests for expedited approval when a showing is made that expedition is necessary, as it has done for California ISO.

• Trans-Elect notes that if a transfer of facilities cannot close under Section 203 until the related FPA section 205 proceeding is concluded, an expedited Section 205 filing must also take place. One way to do this is to waive an Initial Decision and set a date certain for the Commission's section 205 decision.

• PJM/NEPOOL Customers recommend that a standard RTO governance structure be adopted that allows participation by all stakeholder groups. It would expedite processing by requiring that any RTO filing demonstrate that all stakeholders were included in the formation process.

• SMUD recommends that the Final Rule require that RTOs be designed, developed and implemented in a manner that does not require numerous tariff amendments to remedy market ills that could be addressed prospectively or at a speed that does not dramatically increase RTO development costs.

On the other hand, some commenters urged the Commission to exercise caution regarding streamlining and expediting:

• East Texas Cooperatives observes that a poorly configured RTO can potentially be more harmful to the industry than the status quo, by allowing large transmission owners to dominate regional grid management, maintain pancaked rates and discriminate in allocating transmission revenue.

• Indiana Commission recommends that state commissions and other interested parties have full opportunity to thoroughly review, comment, and have an impact on the RTO proposals once they are filed with the Commission.

• Puget indicates that a negative implication of allowing streamlined filing and approval procedures for RTO participants is that regulatory burdens will be leveled against nonparticipants while those who join an RTO will be freed from what the Commission implicitly recognizes are unnecessary requirements. A truly voluntary system would not continue to impose unnecessary regulatory requirements on nonparticipants and there is no reason for the Commission to delay implementing these regulatory reforms now before a final decision is made regarding the wisdom or efficacy of RTOs, or to condition the implementation of such reforms on an entity's participation in an RTO.

• Duke contends that, given the size and complexity of the typical section 203 and 205 of the FPA filings, it is not clear that reducing the time that parties are granted to review such filings and provide initial comments may be appropriate. Nonetheless, the Commission should work to dismiss irrelevant issues used as leverage to extract concessions unrelated to RTO formation, it should consider use of less formal hearing procedures for issues that do not require discovery, and the Commission should limit the time period allowed for evidentiary hearings. Duke acknowledges that the effect of streamlined filing and approval procedures could be to reduce costs that would otherwise be born by market participants.

Commission Conclusion. While there is broad-based consensus for simplifying the Commission's RTO filing process and responding to RTO proposals expeditiously, we must maintain an appropriate balance between streamlining and expediting the filing and processing of RTO proposals and ensuring due process and the development of an adequate record. Given the amount of flexibility we have built into the Rule as to organizational structure, it is difficult to predict what issues will be raised by the RTO proposals and the degree of complexity raised by such issues. Accordingly, while the Commission has the goal of ensuring the rapid formation of RTOs, and will attempt to process each RTO proposal as expeditiously as possible, certain RTO proposals will take longer to analyze and review depending upon the complexity of the issues and the level of support among the affected parties. Therefore, in addition to the specific guidance provided elsewhere in this Rule, we provide further guidance and note the following factors which are intended to assist public utilities in streamlining their required filings and help expedite the processing of the RTO proposals.

One factor that should facilitate faster processing is that the Final Rule permits delayed implementation dates for various highly complex FPA section 205 related RTO provisions (congestion management by December 15, 2002, and parallel path flow coordination and transmission planning and expansion each by December 15, 2003). Therefore, initial RTO proposals need not contain the details for these provisions, but need only contain a commitment to complete the provision and a timetable for submitting appropriate future filings. Likewise, we need not act on those matters initially in our RTO orders.

Expeditious processing of an RTO submittal is more likely to occur if the RTO proposal is the result of a comprehensive and open collaborative process with widespread support from transmission owners, market participants, and affected state commissions. While we cannot pre-approve unopposed proposals, many of our potential concerns could be minimized to the extent the proposal has broad support.

Another potential streamlining measure is that public utilities are permitted to file RTO proposals jointly with other entities. For example, in the case of existing ISOs and other approved regional transmission entities, the regional entity may file on behalf of the individual public utilities. This will reduce the volume of submittals that must be developed by public utilities and be reviewed by the Commission.

We note that, with the exception of governance, experience gained from past ISO proceedings, will be directly transferable whether the form of RTO is an ISO or a transco. For transcos, as discussed elsewhere in the Final Rule, restrictions on ownership of transcos that we have adopted are designed to work in tandem with restrictions on governance in order to ensure adequate levels of independence.

We believe that RTO proposals that reflect the above factors, should allow the Commission to minimize the amount of time necessary to analyze and process the submittal. While the Commission cannot guarantee that we will be able to respond to every proposal within a pre-set period of time, we will make every reasonable effort to issue an initial order on an RTO proposal within 60 days,[750] after the comment period closes.[751] With respect to RTO proposals that present contested issues or problematic RTO provisions, we will make every effort to expedite

[750] We recognize that, while there is no statutory deadline to act on section 203 filings, there is a 60-day statutory clock requiring action on section 205 related filings within 60 days from the date of filing, in the absence of a proposed effective date extending beyond the 60-day time frame. However, in most instances, we expect that the RTO submittals will typically propose FPA section 205 effective dates that will be beyond the 60-day nominal clock.

[751] This proposed time frame refers to applications that are consistent with the guidance provided in this Rule and that provide all the necessary information. We further note that the Commission's review process will restart in the event that applicants modify their proposal or supplement the supporting information in their application.

consideration of the proposed RTO and we will continue to consider alternatives to formal procedures (*e.g., ADR procedures), where warranted, to avoid initiating a hearing.*

What the Commission has approved for ISO forms of governance can be used as models for governance of RTOs that are ISOs. Nothing in this Rule prohibits the types of independent governance structures we have approved to date. All of the ISOs approved to date, except one, have a two-tier form of governance wherein a non-stakeholder board at the top generally has final decision-making authority on most issues. Below this board are advisory groups or committees comprised of stakeholders that provide advice and may share some decision-making authority. With regard to the second-tier, the Commission has required that no one constituency in any group or committee be allowed to dominate the recommendation or decision-making process over the objection of the other classes, and that no one class holds veto power over the will of the remaining classes. The California ISO's governance structure is different. It has a single-tier hybrid decision-making board comprised of both stakeholders and non-stakeholders. No two classes can push through a decision over the objection of other classes, and no one class has veto power over the will of the remaining classes.

4. Other Implementation Issues

Commission Conclusion. An additional issue some commenters raised in connection with implementation concerns how the Commission intends to handle multiple RTO proposals that pertain to the same or overlapping regions. We expect that proper adherence to the collaborative process and the RTO scope and configuration factors we have identified, in the first instance, will bring order to the formation of RTOs such that the Commission will not need to step in and decide the matter of competing RTOs at the filing stage.

Several miscellaneous RTO implementation issues that were raised by some commenters concern the terms of withdrawal for members from an RTO, the RTO's funding of staff compensation in connection with transfers of personnel from other entities, and the Commission serving as a backstop for RTO's ADR processes. These matters, however, are best left to case-specific determinations in response to particular RTO proposals.

In response to those who argue for or against rejection or waiver in connection with less-than-fully-conforming RTO submittals, we believe the concepts of rejection and waiver are not appropriate. We have provided a significant degree of flexibility in the minimum characteristics and functions, and in many instances specifically allow for alternative ways to satisfy those characteristics and functions. Proposals that do not satisfy the minimum characteristics and functions will not be approved as RTOs. That does not mean that such a proposal would be summarily rejected; in fact, it may still be an improvement over the status quo as long as it is consistent with the FPA requirements. However, it may be questioned the extent to which entities that are not participating in RTOs have acted to eliminate the impediments to competition we have identified in this Final Rule.

IV. Environmental Statement

This section reviews and adopts the Environmental Assessment (EA) prepared by the Commission staff in connection with this Final Rule. It identifies the alternatives considered by the agency in reaching its decision; analyzes and considers whether and to what extent, if any, the chosen alternative—adoption of this Final Rule—affects the quality of the human environment; and states the Commission's decision.

Summary

The analysis compares generation and emission trends under the Final Rule to baseline trends without the Final Rule. The analysis indicates that the Final Rule will result in little generation change on a net national basis, but there may be shifts in regional generation. Economic benefits of the Final Rule can be realized with no significant, adverse environmental impacts. Further, the potential exists for environmental benefits to be realized, through the encouragement of newer, cleaner resources.

Discussion

A. Background

To further the policies and goals of the National Environmental Policy Act of 1969 (NEPA), Commission staff prepared an EA in order to examine potential impacts that could result from implementing the Commission's Rule, and to serve as the basis for considering whether the Final Rule will have significant impacts on the quality of the human environment. On May 14, 1999, the Commission issued a notice of intent to prepare an EA, and a request for comments on the scope of the issues that should be addressed in the EA. On July 8, 1999, a public scoping meeting was held at the Commission. On October 22, 1999, the Commission issued an EA, and invited interested parties to comment on the EA. Comments were due on November 22, 1999.

The Commission received two filed comments on the EA (NMA/WFA/CEED and Project Groups on behalf of multiple public interest groups). Specific comments are addressed in the relevant sections below.[752]

B. Scope of the Analysis

The EA examines potential environmental impacts that could result from implementing the Commission's Final Rule. The impacts are necessarily uncertain because they would be the product of changes in economic regulation that may alter the future behavior and perhaps the future structure of electricity supply markets. In turn, these behavioral and structural changes could lead to a different set of environmental conditions than would otherwise be the case. The analysis recognizes the uncertainty of the Rule's potential effects on future markets. It presents a systematic view of possible future market changes and assesses a range of possible responses to market changes, but should not be seen as predictive of specific market or environmental outcomes.

The EA addresses a broad range of potential economic changes that could result from the Rule. These impacts include changes in the mix of electric generating plants built in the future, shifts in the utilization of existing plants, and increases in interregional transmission. The analysis, therefore, includes major air pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury, and carbon dioxide associated with various types of generating plants and fuels. The EA addresses potential environmental impacts at national and regional levels.

Project Groups expressed concern that the EA does not retrospectively analyze the impacts of open access policies to date. As stated in 1.3.2 of the EA, we believe it is neither possible nor desirable to analyze such changes. Data collection lags, and the short period of time that has elapsed since the issuance of Order No. 888, would preclude us from drawing meaningful conclusions.

Project Groups also stated that economic impacts are not specifically reported in the EA, making it more difficult to evaluate the impacts of the

[752] As noted in the EA, a number of comments filed during scoping relate to matters outside the scope of the EA, and for the most part deal with policy issues that are addressed in the Rule.

Rule. We note, however, that the modeling and analysis conducted for the EA are the basis for the economic discussion contained in the Final Rule. These economic results do not provide a complete analysis of the potential economic impacts because the analysis considers only economic effects which may relate to operating decisions or new capacity, and thus may lead to environmental consequences. However, there are other economic benefits from competitive wholesale electric power markets which have little or no effect on the environment.

C. Analytic Approach

Because the impacts that could result from the rulemaking are uncertain, an analytic approach known as scenario analysis was used. In this approach, alternative views of the future are postulated and analyzed with and without the Final Rule. Potential environmental impacts are evaluated by comparing the analytic results of the scenarios. First, an analytic base case was developed. This base case relies on the assumption that the Commission would pursue current policy with respect to wholesale electric competition using existing rules and procedures, including case-by-case implementation of regional market arrangements.

Having established an appropriate base case, the EA analyzed future impacts assuming that the Rule is in effect. Staff adopted the assumption that the Final Rule, although voluntary, would result in the establishment of RTOs throughout the study area with the characteristics and functions set forth in the Final Rule. Three scenarios were developed to reflect a range of possible economic and environmental outcomes: Transmission Efficiency Scenario; Transmission/Generation Efficiency Scenario; New Entry Scenario.

D. Alternatives to the Rule

The primary alternative to the Final Rule is for the Commission to maintain the status quo, that is, to continue its existing open access policies. The result of this no-action alternative, without implementing the Final Rule, is that the Commission would effectuate an open transmission grid, but not address changes in the industry that have occurred since Order No. 888 was adopted. However, the no-action alternative describes what is likely to happen if the Commission takes no action over and beyond implementation of existing policies. Once this baseline is established to portray what is likely to happen in the electric industry during the study period, the projected impacts of the Final Rule can then be determined against this backdrop.

In addition to the Final Rule and the no-action alternative, several alternative approaches were considered and ultimately rejected. The alternative of analyzing mandatory RTOs, as compared with voluntary RTOs as set forth in the Final Rule, was rejected as moot, since the EA assumes that voluntary RTO formation proceeds with little delay and is successful in creating RTOs with the functions and characteristics contained in the Rule. Hence, assumptions for voluntary RTOs and mandatory RTOs are analytically indistinguishable in terms of their effects on the transmission grid and on the electric sector generally.

The other major alternative considered was the analysis of alternative fuel price assumptions. Project for Sustainable FERC Energy Policy suggested that we prepare such an analysis. However, as we noted in the EA, this alternative was ultimately rejected for two reasons. First, as reflected in scenarios analyzed in the EIS for Order No. 888, plausible variation in gas prices relative to coal prices is unlikely to have a major impact on the environmental effects of the Final Rule. Therefore, a gas price scenario was selected that had the general characteristics of other forecasts, namely, that gas prices will rise relative to coal prices. The selection of this gas price scenario does not represent an endorsement of this particular gas price path. Although we believe it to be a reasonable projection, it is a merely a representative projection of gas prices for purposes of the EA. Second, there is no need to consider an alternative where competition favors gas over coal because such a scenario would have little adverse impact, especially when compared with scenarios that tend to favor increased coal use relative to gas use. In the rule scenario we selected, we included, therefore, a number of improvements in coal technology as a result of the RTO Rule, to ensure that the potential impacts of any increased coal use relative to the base case would be considered in assessing the environmental consequences of the rule.

E. Analytic Framework and Assumptions

It is expected that the impacts of the Final Rule will result primarily from changes in the types and locations of power plants and transmission facilities constructed in the future and changes in the operating patterns of existing power plants, including changes in the fuel mix. To examine the impacts thoroughly, the modeling approach chosen includes detailed representations of electric power plants and the electric transmission grid, and allows for an economic (least-cost) compliance with existing and future environmental regulatory requirements.

Computer modeling capable of simulating regional electric utility dispatch and capacity expansion over time was used to characterize electric power markets in the base case and rule scenarios. We used a large supply optimization model of the U.S. electricity supply sector, which emphasizes pollution estimation and pollution control. It has been used for Environmental Protection Agency (EPA) regulatory analysis in publicly accessible proceedings since 1996.

Analytic assumptions are a critical part of the modeling. Because the model cannot tell us directly what the RTO-related changes will be, it must assess how a set of assumed changes in the cost and/or physical properties or the electricity system could lead to changes in the use of the system, and hence to changes in emissions.

A series of specific assumptions were developed to model the base case and scenarios. Assumptions common to all modeled cases include current and future prices of fossil fuels, particularly coal and natural gas, and current and future requirements imposed on the electric sector by environmental laws and regulations. These requirements include: for SO_2, continuation of the Title IV Acid Rain Program, with Phase II coverage and levels of permitted emissions; for NO_X, Title IV requirements on coal-fired boilers (Phase I and Phase II); emissions cap restrictions in the Ozone Transport Region starting in 1999, and implementation of the Final Rule governing ozone transport issued by the EPA in 1997, modeled in accordance with the EPA's guidance. This EPA Rule imposes a cap on NO_X on large utility boilers in 22 states in the eastern United States and limiting summer NO_X emissions to 543,800 tons; no regulatory restrictions are assumed for mercury or CO_2.

Project Groups commented that, since assumptions made in the EA about future environmental regulations are critical in determining the outcome of the analysis, changes in future environmental regulations (particularly due to legal challenges) from those assumed in the EA could result in different environmental impacts. Accordingly, the comment states that the EA should reflect possible changes. We note that there are many important analytic assumptions embodied in the modeling for the EA. Environmental regulations are directly represented in the analysis, and changes in these assumed regulations do have a large effect on the results of the modeling. In particular, the presence or absence of SO_2 and NO_X caps is a key assumption. Nevertheless, these assumptions are based on regulations which are final, as opposed to proposed regulations or speculative regulatory actions. These rules and associated regulatory analyses from EPA were used as the basis for the EA assumptions. Accordingly, it would be premature and speculative to consider changes, if any, from pending legal challenges or speculative future regulatory changes.

In a broader sense, it is clear that successful competitive energy markets will be complemented by cost-effective environmental regulation, because the incentives for efficient behavior on the part of market participants can be decentralized and the need for intrusive regulatory action is lessened. Emissions trading programs such as those for SO_2 and NO_X are an important example of such cost-effective regulation.

Other invariant assumptions include: net electric demand growth (with the exception of New Entry Scenario); load shape (how demand varies with season and time of day within each model region); costs and performance of new power plants; and capacity and generation of nuclear, hydroelectric, pumped storage, and import supply.

Because of the importance of the transmission system in the Rule, assumptions were made about potential changes that may come about either because of the Rule's requirements or because of its increased incentives for better grid operation and investment. In addition, the Final Rule is expected to develop more competitive bulk electric power markets. Competition is expected to increase the incentives for efficient behavior among market participants. To assess the potential effects of such increased efficiencies on the environment, some assumptions affecting new and existing power plants were changed. Finally, to respond to concerns expressed by parties in the scoping process regarding the role of new entrants in developing competitive power markets, particularly the RTOs, a model scenario was developed that specifically addresses new entry and enhanced consumer choice.

F. Impacts

The EA analyzes the electric power capacity and generation projections on a national and regional level for the base case, and presents the corresponding environmental impacts. Projected trends in generating capacity, including economic additions, retirements and modifications, and generation by plant type for the base case, are analyzed for the years 2005, 2010, and 2015. The data indicate that virtually all future capacity additions are expected to be gas-fired combined cycle or combustion turbine units; coal will nevertheless remain the dominant fuel for generation. Growth in natural gas, however, will be rapid, with the share of generation increasing from 13 percent in 1997 to 32 percent in 2015; total generating capacity is expected to grow at a slower rate than demand, resulting in plants that will generally be operated at higher capacity factors; regional patterns of generation reflect regional demand growth as well as changes in interregional trade in electricity. In most regions, growth in demand is met by gas-fired (or oil/gas switching) plants, although in the Midwest existing coal-fired capacity meets part of the growth in the early years of the forecast.

The EA projects national emissions in the base case for SO_2, NO_X, mercury, and CO_2. There are also regional emissions projections for NO_X. The analysis indicates the following:

1. SO_2 emissions will decline gradually to 9.5 million tons in 2015. Variations in such emissions during the forecast period primarily reflect economic use of the Title IV emissions banking program, under which emitting parties may elect to over-control SO_2 in any year and bank the extra reductions as emission credits for later use;

2. Regional SO_2 emissions generally will follow the same pattern as the national emissions total. However, emissions reductions and shifts are not expected to occur uniformly across regions because the SO_2 emissions trading program allows emitting parties with higher costs of pollution control to purchase allowances from emitting parties with lower control costs. This can lead to increases in emissions from certain regions;

3. NO_X emissions are projected to decline to 4.1 million tons in 2015. These reductions are due to the development of NO_X regulations under the Clean Air Act. Furthermore, summer or ''ozone season'' (May to September) NO_X emissions are projected to decrease to 1.3 million tons in 2015;

4. Regional NO_X emissions are projected to follow a pattern similar to the national trend; however, the implementation of NO_X controls is assumed to take the form of an emission cap and permit trading program similar to the Title IV SO_2 program. Consequently, certain regions may experience different NO_X emissions trends because of the relative costs of controlling NO_X and the possibility of trading between emitting parties;

5. CO_2 is projected to increase throughout the analysis period by 27 percent. Because CO_2 is an unregulated pollutant at the present time, and because both coal and natural gas emit CO_2, the rise in both coal and gas-fired generation leads to a substantial increase in CO_2 emissions during the analysis period; and

6. Mercury emissions range between 50.6 and 53.2 tons during the forecast period with no clear trend distinguishable. Mercury is also uncontrolled at the present time, but emissions are closely linked to coal use (with considerable variation of mercury content in coal from specific seams). The relative stability of coal-fired generation in later years of the analysis period leads to the observed pattern of mercury emissions.

The analysis indicates that the Midwest is expected to produce slightly more power, the East Coast to produce slightly less power. These changes are likely to be greatest in the near-term, and to decline toward baseline levels over time. The Final Rule would result in the slight shifting of the baseline fuel mix projections toward coal and away from fuel oil and, to some extent, natural gas; these changes are small relative to the overall trend in the fuel mix, in which natural gas remains the most rapidly growing fuel. This is consistent with the change in regional levels of generation.

The analysis shows that the overall emissions of SO_X, NO_X, mercury, and CO_2, are directionally consistent with the observed changes in power generation and fuel mix. That is, emissions tend to increase early in the forecast period and then decline over time, with several instances of emissions reductions. The greatest change in any regulated pollutant (a rise of 3.6 percent or 381,000 tons of SO_2 in one scenario) occurs as a result of changing patterns of emissions banking and trading, which is consistent with the design of the SO_2 cap and trade regulatory program. Regional variations in annual and summer NO_X are also possible and are also consistent with regulatory program design. Emissions budgets are met at all times. Other emission changes are relatively small because coal-fired plants, which contribute a disproportionate share of these emissions, are already heavily utilized and so are unable to increase their output significantly in the rulemaking scenarios. In one scenario designed to examine increased new entry and demand flexibility, substantial emissions reductions occur as a result of lower demand for electricity combined with cleaner new supply options.

V. Regulatory Flexibility Act Certification

The Commission received no comments on its certification, in the NOPR, that the proposed rule would not have a significant economic impact on a substantial number of small entities and that an initial regulatory flexibility analysis is not required by 5 U.S.C. § 603. The Commission adheres to its earlier reasoning and thus concludes that a final regulatory flexibility analysis also is not required.[753] In making this determination, the Commission is required to examine only the direct compliance costs that a rulemaking imposes upon small businesses. It is not required to consider indirect economic consequences, nor is it required to consider costs that an entity incurs voluntarily.[754] This rulemaking does not impose significant compliance costs upon small entities. Instead, it leaves them with the choice of whether to join an RTO. The only costs that are mandated are the minimal costs associated with filing a statement, in the event a public utility does not make an RTO filing, explaining its efforts to join an RTO, any barriers it encountered, and any future plans to join an RTO. Thus, this rulemaking will not have a significant economic impact upon any small entities.

VI. Public Reporting Burden and Information Collection Statement

The OMB regulations require OMB to approve certain reporting and recordkeeping (collections of information) imposed by agency rule.[755] The NOPR was submitted to OMB at the time of issuance. OMB did not comment nor did it take any action on the proposed rule. FERC identifies the information provided under Part 35 as FERC–516 [756] and under Part 33 as FERC–519.[757]

No comments from the public on the burden estimate were received. The filing requirements remain essentially the same as those in the NOPR so, therefore, the estimated annual filing burden remains the same. The burden estimates for complying with this proposed rule are set out in Table 1. The total annual hours for collection (reporting + recordkeeping (if appropriate)) is 7,600.

Information Collection Costs: The Commission has projected the average annualized cost for all respondents to be: Annualized Costs (Operations & Maintenance): $401,518 (7,600 hours ÷ 2080 hours per year × $109,889=$401,518). The cost per respondent is $7,722 (participants and non-participants).

TABLE 1.—ESTIMATED ANNUAL BURDEN

Data Collection	Number of Respondents	Number of Responses	Hours Per Response	Total Annual Hours
FERC–516 [1]	12	1	300	3,600
FERC–516 [2]	40	1	40	1,600
FERC–519 [1]	12	1	200	2,400
Totals	....	....	....	7,600

[1] Filings to propose participation in an RTO under § 35.34(d).
[2] Alternative filings under § 35.34(g).

Comments were solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Title: FERC–516, Electric Rate Schedule Filings; FERC–519 Application for Sale, Lease, or Other Disposition, Merger or Consolidation of Facilities or for the Purchase or Acquisition of Securities of a Public Utility.

Action: Proposed Data Collections.

OMB Control No.: 1902–0096 and 1902–0082.

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit, including small businesses.

Frequency of Responses: One time.

Necessity of Information: The Final Rule revises the requirements contained in 18 CFR part 35. The Commission is promoting the voluntary establishment of RTOs nationwide by December 2001. In particular, the Commission will establish in this rule characteristics and functions which applicants must meet to become Commission-approved RTOs. The Commission will engage in a collaborative process with state officials and others to facilitate RTO development. The rule will require that each public utility that owns, operates or controls transmission facilities participate in one-time filings proposing an RTO or make a filing explaining why they are not participating in an RTO proposal.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Office of Markets, Tariffs and Rates will use the data included in filings under 18 CFR 35.34 to evaluate efforts for the interconnection and coordination of the U.S. electric transmission system and to ensure the orderly formation of RTOs as well as for general industry oversight. These information requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric power industry.

The Commission received approximately 334 comments and reply comments on its NOPR but none on its reporting burden. The Commission's responses to the comments are addressed in the preamble of this Final

[753] *See* 5 U.S.C. 604.

[754] *Mid-Tex Elec. Coop.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985) (Commission need only consider small entities ''that would be directly regulated''); *Colorado State Banking Bd.* v. *RTC,* 926 F.2d 931 (10th Cir. 1991) (Regulatory Flexibility Act not implicated where regulation simply added an option for affected entities and did not impose any costs).

[755] 5 CFR 1320.11, 44 U.S.C. 3507(d).

[756] Electric Rate Schedule Filings.

[757] Application for Sale, Lease, or Other Disposition, Merger or Consolidation of Facilities or for the Purchase or Acquisition of Securities of a Public Utility.

Rule. The Commission is submitting a copy of the Final Rule along with information collection submissions for the data collections identified above to OMB for its review and approval.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Michael Miller, Office of the Chief Information Officer, Phone: (202) 208–1415, fax: (202) 208–2425, E-mail: *mike.miller@ferc.fed.us*] or send your comments to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503, [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–3087, fax: (202) 395–7285].

VII. Effective Date and Congressional Notification

This rule will take effect March 6, 2000. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this Rule is a ''major rule'' within the meaning of section 351 of the Small Business Regulatory Enforcement Act of 1996.[758] The Rule will be submitted to both Houses of Congress and the Comptroller General prior to its publication in the **Federal Register**.

VIII. Document Availability

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 FERC's Home Page (*http://www.ferc.fed.us*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

From FERC's Home Page on the Internet, this information is available in both the Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS).

- CIPS provides access to the texts of formal documents issued by the Commission since November 14, 1994. CIPS can be accessed using the CIPS link or the Energy Information Online icon. The full text of this document will be available on CIPS in ASCII and WordPerfect 8.0 format for viewing, printing, and/or downloading.
- RIMS contains images of documents submitted to and issues by the Commission after November 16, 1981. Documents from November 1995 to the present can be viewed and printed from FERC's Home Page using the RIMS link or the Energy Information Online icon. Descriptions of documents back to November 16, 1981, are also available from RIMS-on-the-Web; requests for copies of these and other older documents should be submitted to the Public Reference Room.

User assistance is available for RIMS, CIPS, and the Website during normal business hours from our Help line at (202) 208–2222 (e-mail to WebMaster@ferc.fed.us) of the Public Reference Room at (202) 208–1371 (e-mail to *public.referenceroom@ferc.fed.us*).

During normal business hours, documents can also be viewed and/or printed in FERC's Public Reference Room, where RIMS, CIPS, and the FERC Website are available. User assistance is also available.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements

By the Commission.

David P. Boergers,

Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18 of the *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by adding a new Subpart F and a new § 35.34 to read as follows:

Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

§ 35.34 Regional Transmission Organizations.

(a) *Purpose.* This section establishes required characteristics and functions for Regional Transmission Organizations for the purpose of promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services. This section further directs each public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce to make certain filings with respect to forming and participating in a Regional Transmission Organization.

(b) *Definitions.*

(1) *Regional Transmission Organization* means an entity that satisfies the minimum characteristics set forth in paragraph (j) of this section, performs the functions set forth in paragraph (k) of this section, and accommodates the open architecture condition set forth in paragraph (l) of this section.

(2) *Market participant* means:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides transmission or ancillary services to the Regional Transmission Organization, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions.

(3) *Affiliate* means the definition given in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11)).

(4) *Class of market participants* means two or more market participants with common economic or commercial interests.

(c) *General rule.* Except for those public utilities subject to the requirements of paragraph (h) of this section, every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000 must file with the Commission, no later than October 15, 2000, one of the following:

(1) A proposal to participate in a Regional Transmission Organization consisting of one of the types of submittals set forth in paragraph (d) of this section; or

(2) An alternative filing consistent with paragraph (g) of this section.

(d) *Proposal to participate in a Regional Transmission Organization.* For purposes of this section, a proposal to participate in a Regional Transmission Organization means:

(1) Such filings, made individually or jointly with other entities, pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as are necessary to create a new Regional Transmission Organization;

[758] 5 U.S.C. 804(2).

(2) Such filings, made individually or jointly with other entities, pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as are necessary to join a Regional Transmission Organization approved by the Commission on or before the date of the filing; or

(3) A petition for declaratory order, filed individually or jointly with other entities, asking whether a proposed transmission entity would qualify as a Regional Transmission Organization and containing at least the following:

(i) A detailed description of the proposed transmission entity, including a description of the organizational and operational structure and the intended participants;

(ii) A discussion of how the transmission entity would satisfy each of the characteristics and functions of a Regional Transmission Organization specified in paragraphs (j), (k) and (l) of this section;

(iii) A detailed description of the Federal Power Act section 205 rates that will be filed for the Regional Transmission Organization; and

(iv) A commitment to make filings pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as necessary, promptly after the Commission issues an order in response to the petition.

(4) Any proposal filed under this paragraph (d) must include an explanation of efforts made to include public power entities in the proposed Regional Transmission Organization.

(e) *Innovative transmission rate treatments for Regional Transmission Organizations.*

(1) The Commission will consider authorizing any innovative transmission rate treatment, as discussed in this paragraph (e), for an approved Regional Transmission Organization. An applicant's request must include:

(i) A detailed explanation of how any proposed rate treatment would help achieve the goals of Regional Transmission Organizations, including efficient use of and investment in the transmission system and reliability benefits to consumers;

(ii) A cost-benefit analysis, including rate impacts; and

(iii) A detailed explanation of why the proposed rate treatment is appropriate for the Regional Transmission Organization.

The applicant must support any rate proposal under this paragraph (e) as just, reasonable, and not unduly discriminatory or preferential.

(2) For purposes of this paragraph (e), innovative transmission rate treatment means any of the following:

(i) A transmission rate moratorium, which may include proposals based on formerly bundled retail transmission rates;

(ii) Rates of return that:

(A) Are formulary;

(B) Consider risk premiums and account for demonstrated adjustments in risk; or

(C) Do not vary with capital structure;

(iii) Non-traditional depreciation schedules for new transmission investment;

(iv) Transmission rates based on levelized recovery of capital costs;

(v) Transmission rates that combine elements of incremental cost pricing for new transmission facilities with an embedded-cost access fee for existing transmission facilities; or

(vi) Performance-based transmission rates.

(3) A request for performance-based transmission rates under this paragraph (e) may include factors such as:

(i) A method for calculating initial transmission rates (including price caps and any provisions for discounting);

(ii) A mechanism for adjusting initial rates, which may be derived from or based upon external factors or indices or a specific performance measure;

(iii) Time periods for redetermining initial rates; and

(iv) Costs to be excluded from performance-based rates.

(4) An innovative transmission rate treatment or any other rate proposal made for an approved Regional Transmission Organization may be requested as part of any filing that is made under paragraph (d) of this section or in any subsequent rate change proposal under section 205 of the Federal Power Act (16 U.S.C. 824d). Unless otherwise ordered by the Commission, an approved Regional Transmission Organization may not include in rates any innovative transmission rate treatment under paragraphs (e)(2)(i) and (e)(2)(ii)(C) of this section after January 1, 2005.

(f) *Transfer of operational control.* The public utility's proposal to participate in a Regional Transmission Organization filed pursuant to paragraph (c)(1) of this section must propose that operational control of that public utility's transmission facilities will be transferred to the Regional Transmission Organization on a schedule that will allow the Regional Transmission Organization to commence operating the facilities no later than December 15, 2001.

Note to paragraph (f): The requirement in paragraph (f) of this section may be satisfied by proposing to transfer to the Regional Transmission Organization ownership of the facilities in addition to operational control.

(g) *Alternative filing.* Any filing made pursuant to paragraph (c)(2) of this section must contain:

(1) A description of any efforts made by that public utility to participate in a Regional Transmission Organization;

(2) A detailed explanation of the economic, operational, commercial, regulatory, or other reasons the public utility has not made a filing to participate in a Regional Transmission Organization, including identification of any existing obstacles to participation in a Regional Transmission Organization; and

(3) The specific plans, if any, the public utility has for further work toward participation in a Regional Transmission Organization, a proposed timetable for such activity, an explanation of efforts made to include public power entities in the proposed Regional Transmission Organization, and any factors (including any law, rule or regulation) that may affect the public utility's ability or decision to participate in a Regional Transmission Organization.

(h) *Public utilities participating in approved transmission entities.* Every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, and that has filed with the Commission on or before March 6, 2000 to transfer operational control of its facilities to a transmission entity that has been approved or conditionally approved by the Commission on or before March 6, 2000 as being in conformance with the eleven ISO principles set forth in Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs), must, individually or jointly with other entities, file with the Commission, no later than January 15, 2001:

(1) A statement that it is participating in a transmission entity that has been so approved;

(2) A detailed explanation of the extent to which the transmission entity in which it participates has the characteristics and performs the functions of a Regional Transmission Organization specified in paragraphs (j) and (k) of this section and accommodates the open architecture conditions in paragraph (l) of this section; and

(3) To the extent the transmission entity in which the public utility participates does not meet all the requirements of a Regional Transmission Organization specified in paragraphs (j), (k), and (l) of this section,

(i) A proposal to participate in a Regional Transmission Organization that meets such requirements in accordance with paragraph (d) of this section,

(ii) A proposal to modify the existing transmission entity so that it conforms to the requirements of a Regional Transmission Organization, or

(iii) A filing containing the information specified in paragraph (g) of this section addressing any efforts, obstacles, and plans with respect to conformance with those requirements.

(i) *Entities that become public utilities with transmission facilities.* An entity that is not a public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, but later becomes such a public utility, must file a proposal to participate in a Regional Transmission Organization in accordance with paragraph (d) of this section, or an alternative filing in accordance with paragraph (g) of this section, by October 15, 2000 or 60 days prior to the date on which the public utility engages in any transmission of electric energy in interstate commerce, whichever comes later. If a proposal to participate in accordance with paragraph (d) of this section is filed, it must propose that operational control of the applicant's transmission system will be transferred to the Regional Transmission Organization within six months of filing the proposal.

(j) *Required characteristics for a Regional Transmission Organization.* A Regional Transmission Organization must satisfy the following characteristics when it commences operation:

(1) *Independence.* The Regional Transmission Organization must be independent of any market participant. The Regional Transmission Organization must include, as part of its demonstration of independence, a demonstration that it meets the following:

(i) The Regional Transmission Organization, its employees, and any non-stakeholder directors must not have financial interests in any market participant.

(ii) The Regional Transmission Organization must have a decision making process that is independent of control by any market participant or class of participants.

(iii) The Regional Transmission Organization must have exclusive and independent authority under section 205 of the Federal Power Act (16 U.S.C. 824d), to propose rates, terms and conditions of transmission service provided over the facilities it operates. Note to paragraph (j)(1)(iii): Transmission owners retain authority under section 205 of the Federal Power Act (16 U.S.C. 824d) to seek recovery from the Regional Transmission Organization of the revenue requirements associated with the transmission facilities that they own.

(2) *Scope and regional configuration.* The Regional Transmission Organization must serve an appropriate region. The region must be of sufficient scope and configuration to permit the Regional Transmission Organization to maintain reliability, effectively perform its required functions, and support efficient and non-discriminatory power markets.

(3) *Operational authority.* The Regional Transmission Organization must have operational authority for all transmission facilities under its control. The Regional Transmission Organization must include, as part of its demonstration of operational authority, a demonstration that it meets the following:

(i) If any operational functions are delegated to, or shared with, entities other than the Regional Transmission Organization, the Regional Transmission Organization must ensure that this sharing of operational authority will not adversely affect reliability or provide any market participant with an unfair competitive advantage. Within two years after initial operation as a Regional Transmission Organization, the Regional Transmission Organization must prepare a public report that assesses whether any division of operational authority hinders the Regional Transmission Organization in providing reliable, non-discriminatory and efficiently priced transmission service.

(ii) The Regional Transmission Organization must be the security coordinator for the facilities that it controls.

(4) *Short-term reliability.* The Regional Transmission Organization must have exclusive authority for maintaining the short-term reliability of the grid that it operates. The Regional Transmission Organization must include, as part of its demonstration with respect to reliability, a demonstration that it meets the following:

(i) The Regional Transmission Organization must have exclusive authority for receiving, confirming and implementing all interchange schedules.

(ii) The Regional Transmission Organization must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities.

(iii) When the Regional Transmission Organization operates transmission facilities owned by other entities, the Regional Transmission Organization must have authority to approve or disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards.

(iv) If the Regional Transmission Organization operates under reliability standards established by another entity (*e.g.,* a regional reliability council), the Regional Transmission Organization must report to the Commission if these standards hinder it from providing reliable, non-discriminatory and efficiently priced transmission service.

(k) *Required functions of a Regional Transmission Organization.* The Regional Transmission Organization must perform the following functions. Unless otherwise noted, the Regional Transmission Organization must satisfy these obligations when it commences operations.

(1) *Tariff administration and design.* The Regional Transmission Organization must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities. As part of its demonstration with respect to tariff administration and design, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(1) (i) and (ii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The Regional Transmission Organization must have the authority to review and approve requests for new interconnections.

(ii) Customers under the Regional Transmission Organization tariff must not be charged multiple access fees for the recovery of capital costs for transmission service over facilities that the Regional Transmission Organization controls.

(2) *Congestion management.* The Regional Transmission Organization must ensure the development and operation of market mechanisms to

manage transmission congestion. As part of its demonstration with respect to congestion management, the Regional Transmission Organization must satisfy the standards listed in paragraph (k)(2)(i) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions. The Regional Transmission Organization must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant.

(ii) The Regional Transmission Organization must satisfy the market mechanism requirement no later than one year after it commences initial operation. However, it must have in place at the time of initial operation an effective protocol for managing congestion.

(3) *Parallel path flow.* The Regional Transmission Organization must develop and implement procedures to address parallel path flow issues within its region and with other regions. The Regional Transmission Organization must satisfy this requirement with respect to coordination with other regions no later than three years after it commences initial operation.

(4) *Ancillary services.* The Regional Transmission Organization must serve as a provider of last resort of all ancillary services required by Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders. As part of its demonstration with respect to ancillary services, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(4)(i)–(iii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) All market participants must have the option of self-supplying or acquiring ancillary services from third parties subject to any restrictions imposed by the Commission in Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders.

(ii) The Regional Transmission Organization must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All ancillary service providers must be subject to direct or indirect operational control by the Regional Transmission Organization. The Regional Transmission Organization must promote the development of competitive markets for ancillary services whenever feasible.

(iii) The Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate this market itself or ensure that this task is performed by another entity that is not affiliated with any market participant.

(5) *OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC).* The Regional Transmission Organization must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.

(6) *Market monitoring.* To ensure that the Regional Transmission Organization provides reliable, efficient and not unduly discriminatory transmission service, the Regional Transmission Organization must provide for objective monitoring of markets it operates or administers to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions. As part of its demonstration with respect to market monitoring, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(6)(i) through (k)(6)(iii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) Market monitoring must include monitoring the behavior of market participants in the region, including transmission owners other than the Regional Transmission Organization, if any, to determine if their actions hinder the Regional Transmission Organization in providing reliable, efficient and not unduly discriminatory transmission service.

(ii) With respect to markets the Regional Transmission Organization operates or administers, there must be a periodic assessment of how behavior in markets operated by others (*e.g.,* bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects Regional Transmission Organization operations and how Regional Transmission Organization operations affect the efficiency of power markets operated by others.

(iii) Reports on opportunities for efficiency improvement, market power abuses and market design flaws must be filed with the Commission and affected regulatory authorities.

(7) *Planning and expansion.* The Regional Transmission Organization must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with the appropriate state authorities. As part of its demonstration with respect to planning and expansion, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(7)(i) and (ii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization planning and expansion process must encourage market-driven operating and investment actions for preventing and relieving congestion.

(ii) The Regional Transmission Organization's planning and expansion process must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Regional Transmission Organization's planning and expansion process must be coordinated with programs of existing Regional Transmission Groups (See § 2.21 of this chapter) where appropriate.

(iii) If the Regional Transmission Organization is unable to satisfy this requirement when it commences operation, it must file with the Commission a plan with specified milestones that will ensure that it meets this requirement no later than three years after initial operation.

(8) *Interregional coordination.* The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

(l) *Open architecture.*

(1) Any proposal to participate in a Regional Transmission Organization must not contain any provision that would limit the capability of the Regional Transmission Organization to evolve in ways that would improve its efficiency, consistent with the requirements in paragraphs (j) and (k) of this section.

(2) Nothing in this regulation precludes an approved Regional Transmission Organization from seeking to evolve with respect to its organizational design, market design,

geographic scope, ownership arrangements, or methods of operational control, or in other appropriate ways if the change is consistent with the requirements of this section. Any future filing seeking approval of such changes must demonstrate that the proposed changes will meet the requirements of paragraphs (j), (k) and (l) of this section.

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix to Preamble—List of Commenters

Abbreviation—Commenter

1. Advisory Committee ISO–NE—Advisory Committee to the Board of Directors of ISO New England.
2. AEP—American Electric Power Service Corporation and its public utility operating company subsidiaries: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company. and Wheeling Power Company.
3. AEPCO—Arizona Electric Power Cooperative, Inc.
4. Alabama Commission—Alabama Public Service Commission.
5. Alberta—Provence of Alberta, Electricity Branch.
6. Allegheny—Allegheny Energy, Inc.
7. Alliance Companies—American Electric Power Service Corporation, Consumers Energy Company, Detroit Edison Company, FirstEnergy Corp. and Virginia Electric and Power Company.
8. Alliant Energy—Alliant Energy Corporation.
9. Aluminum Companies—Alcoa Inc., Columbia Falls Aluminum Company, Kaiser Aluminum & Chemical Corporation and Vanalco, Inc.
10. American Forest—American Forest & Paper Association.
11. AMP-Ohio—American Municipal Power-Ohio, Inc.
12. APPA—American Public Power Association.
13. APPA *et al.* (WP)—Legal White Paper prepared on behalf of and sponsored jointly by the American Public Power Association, the Electric Consumers Resource Council, the Transmission Access Policy Study Group and the Transmission Dependent Utility Systems.
14. APS—Arizona Public Service Company.
15. APX—Automated Power Exchange, Inc.
16. Arizona Authority—Arizona Power Authority.
17. Arizona Commission—Arizona Corporation Commission.
18. Arizona ISA—Arizona Independent Scheduling Administrator Association.
19. Arkansas Cities—Cities of Benton, Bentonville, North Little Rock, Osceola, Piggott, Prescott and Siloam Springs, Arkansas; the Clarksville Light and Water Company; Conway Corporation; Hope Water and Light Commission; City Water and Light Plant of the City of Jonesboro, Arkansas; Paragould Light and Water Commission; and the West Memphis, Arkansas Utilities Commission.
20. Arkansas Consumers—Arkansas Electric Energy Consumers.
21. Avista—Avista Corporation, Inc.
22. Bangor Hydro—Bangor Hydro-Electric Company.
23. BC Hydro—British Columbia Hydro & Power Authority.
24. Big Rivers—Big Rivers Electric Corporation.
25. Blue Ridge—Blue Ridge Power Agency.
26. Brattle Group—The Brattle Group (Peter Fox-Penner and Philip Hanser).
27. British Columbia Ministry—British Columbia, Canada, Ministry of Employment and Investment, Electricity Development Branch.
28. Cal DWR—California Department of Water Resources.
29. Cal ISO—California Independent System Operator Corporation.
30. California Board—California Electricity Oversight Board.
31. California Commission—Public Utilities Commission of the State of California.
32. CalPX—California Power Exchange Corporation.
33. CAMU—Colorado Association of Municipal Utilities.
34. Canada DNR—Canada Department of Natural Resources.
35. CCEM/ELCON—Coalition for a Competitive Electricity Market and the Electricity Consumers Resources Council.
36. CEA—Canadian Electricity Association.
37. Consumers Energy—Consumers Energy Company.
38. Central Maine—Central Maine Power Company and Maine Electric Power Company.
39. Champion—Champion International Corporation.
40. Chelan—Public Utility District No. 1 of Chelan County.
41. Cinergy—Cinergy Services, Inc.
42. Clarksdale—Clarksdale Public Utilities Commission.
43. Cleco—Cleco Corporation.
44. Cleveland—City of Cleveland, Ohio.
45. CMUA—California Municipal Utilities Association.
46. Coalition of Alliance Users—Coalition of Municipal and Cooperative Users of Alliance Companies' Transmission.
47. ComEd—Commonwealth Edison Company.
48. Conectiv—Conectiv (Atlantic City Electric Company and Delmarva Power & Light Company.
49. Conlon—Mr. P. Gregory Conlon.
50. Consumer Groups—Industrial Consumers, American Public Power Association, National Rural Electric Cooperative Association, Transmission Access Policy Study Group, Transmission Dependent Utility Systems, Consumer Federation of America and International Mass Retail Association.
51. CP&L—Carolina Power & Light Company.
52. CRC—Colorado River Commission of the State of Nevada.
53. CREDA—Colorado River Energy Distributors Association.
54. CSU—Colorado Springs Utilities.
55. CTA—Competitive Transmission Association, Inc.
56. Dalton Utilities—Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia.
57. Dairyland—Dairyland Power Cooperative.
58. Desert STAR—Desert STAR.
59. Detroit Edison—Detroit Edison Company.
60. Distributed Power—Distributed Power Coalition of America.
61. DOE—United States Department of Energy.
62. Dr. Illic—Dr. Marija Illic and Yong Yoon.
63. Duke—Duke Energy Corporation.
64. Duquesne—Duquesne Light Company.
65. Dynegy—Dynegy Inc.
66. EAL—ESBI Alberta Ltd.
67. East Kentucky—East Kentucky Power Cooperative, Inc.
68. East Texas Cooperatives—East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc.
69. ECAR—East Central Area Reliability Council.
70. EEI—Edison Electric Institute.
71. EME—Edison Mission Energy.
72. Empire District—Empire District Electric Company.
73. Enron/APX/Coral Power—Enron Power Marketing, Inc., Automated Power Exchange and Coral Power, L.L.C.
74. Entergy—Entergy Services Inc.
75. EPA—United States Environmental Protection Agency.
76. EPRI—Electric Power Research Institute.
77. EPSA—Electric Power Supply Association.
78. Eric Hirst—Mr. Eric Hirst.
79. Fertilizer Institute—The Fertilizer Institute.
80. First Rochdale—1st Rochdale Cooperative Group, Ltd.
81. FirstEnergy—FirstEnergy Corp.
82. Florida Commission—Florida Public Service Commission.
83. Florida Power Corp.—Florida Power Corporation.
84. FMPA—Florida Municipal Power Agency.
85. FP&L—Florida Power & Light Company.
86. FTC—Staff of the Bureau of Economics of the Federal Trade Commission.
87. Gainesville—Gainesville Regional Utilities.
88. Georgia Transmission—Georgia Transmission Corporation.
89. GPU Energy—GPU Energy.
90. Grand Council et al.—Grand Council of the Crees, Greenpeace Canada, the Sierra Club of Canada, Mouvement Au Courant, the Centre D'Analyses de Politiques Energetiques and New England Coalition for Energy Efficiency and the Environment.
91. Great River—Great River Energy.
92. H.Q. Energy Services—Energy Services Group of Hydro-Quebec and H.Q. Energy Services (U.S.) Inc.
93. How Group—OASIS How Working Group.
94. ICUA—Idaho Consumer-Owned Utilities Association.

95. Idaho Commission—Idaho Public Utilities Commission.
96. Idaho Power—Idaho Power Company.
97. Illinois Commission—Illinois Commerce Commission.
98. IMEA—Illinois Municipal Electric Agency.
99. IMPA—Indiana Municipal Power Agency.
100. Indiana Commission—Indiana Utility Regulatory Commission.
101. Indianapolis P&L—Indianapolis Power & Light Company.
102. Industrial Consumers—Electricity Consumers Resource Council, the American Iron & Steel Institute and the Chemical Manufactures Association.
103. Industrial Customers—Industrial Customers of Northwest Utilities.
104. INGAA—Interstate Natural Gas Association of America.
105. Iowa Board—Iowa Utilities Board.
106. IPCF—International Powerline Communications Forum.
107. ISO–NE—ISO New England Inc.
108. JEA—JEA.
109. Justice Department—United States Department of Justice.
110. Kentucky Commission—Kentucky Public Service Commission.
111. Konolige/Ford/Fleishman—Kit Konolige, Daniel F. Ford and Steven I. Fleishman.
112. Lenard—Mr. Thomas M. Lenard.
113. LEPA—Louisiana Energy & Power Authority.
114. LG&E—LG&E Energy Corp.
115. Lincoln—Lincoln, Nebraska Electric System.
116. LIPA—Long Island Power Authority.
117. Los Angeles—Los Angeles Department of Water and Power.
118. Loveland Customers—Loveland Area Customers Association.
119. LPPC—Large Public Power Council.
120. Manitoba Board—Manitoba Hydro-Electric Board.
121. MAPP—Mid-Continent Area Power Pool.
122. Mass Companies—Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company.
123. Massachusetts Division—Massachusetts Division of Energy Resources.
124. MEAG—Municipal Electric Authority of Georgia.
125. Merrill Energy—Merrill Energy LLC.
126. Metropolitan—Metropolitan Water District of Southern California.
127. Michigan Commission—Michigan Public Service Commission.
128. MidAmerican—MidAmerican Energy Company.
129. Mid-Atlantic Commissions—Delaware Public Service Commission, District of Columbia Public Service Commission, Maryland Public Service Commission, New Jersey Board of Public Utilities and Pennsylvania Public Utility Commission.
130. Midwest Energy—Midwest Energy, Inc.
131. Midwest ISO—Midwest Independent Transmission System Operator, Inc.
132. Midwest ISO Participants—Allegheny Energy, Ameren, Central Illinois Light Company, Cinergy Corp., Commonwealth Edison Company, Hoosier Energy Rural Electric Cooperative, Inc., Illinois Power Company, Kentucky Utilities Company, Louisville Gas & Electric Company, Southern Indiana Gas & Electric Company, Southern Illinois Power Cooperative, Wabash Valley Power Association, Inc. and Wisconsin Electric Power Company.
133. Midwest Municipals—Missouri River Energy Services, Iowa Association of Municipal Utilities and Minnesota Municipal Utilities Association.
134. Minnesota Commission—Minnesota Public Utilities Commission.
135. Minnesota Power—Minnesota Power.
136. Missouri Commission—Missouri Public Service Commission.
137. MLGW—Memphis Light, Gas and Water Division.
138. Montana Commission—Montana Public Service Commission and Montana Department of Environmental Quality.
139. Montana Power—Montana Power Company.
140. Montana-Dakota—Montana-Dakota Utilities Co.
141. NARUC—National Association of Regulatory Utility Commissioners.
142. NASUCA—National Association of State Utility Consumer Advocates.
143. NCPA—Northern California Power Agency.
144. NEMA—National Energy Marketers Association.
145. NECPUC—New England Conference of Public Utilities Commissioners, Inc.
146. NEPCO et al.—New England Power Company, National Grid Group, plc and Montaup Electric Company.
147. NERA—National Economic Research Associates, Inc.
148. NERC—North American Electric Reliability Council.
149. Nevada Commission—Public Utilities Commission of Nevada
150. New Century—New Century Energies, Inc. and its operating utility companies: Public Service Company of Colorado, Southwestern Public Service Company and Cheyenne Light, Fuel and Power Company.
151. New Orleans—Council of the City of New Orleans.
152. New Smyrna Beach—Utilities Commission, City of New Smyrna Beach, Florida.
153. New York Commission—New York State Public Service Commission
154. Nine Commissions—Pennsylvania Public Utility Commission, Virginia State Corporation Commission, Public Utilities Commission of Ohio, Indiana Utility Regulatory Commission, Illinois Commerce Commission, Michigan Public Service Commission, Missouri Public Service Commission, Arkansas Public Service Commission and Oklahoma Corporation Commission.
155. NiSource—NiSource Incorporated.
156. NJBUS—New Jersey Business Users.
157. NMA/WFA/CEED—National Mining Association, Western Fuels Association, Inc. and Center for Energy and Economic Development.
158. NU—Northeast Utilities System.
159. Northwest Council—Northwest Power Planning Council.
160. NPCC—Northeast Power Coordinating Council.
161. NPPD—Nebraska Public Power District.
162. NPRB—Nebraska Power Review Board.
163. NRECA—National Rural Electric Cooperative Association.
164. NSP—Northern States Power Company.
165. NU—Northeast Utilities System.
166. NWCC—National Wind Coordinating Committee.
167. NY ISO—New York Independent System Operator, Inc.
168. NYC—City of New York.
169. NYEBF—New York Energy Buyers Forum.
170. NYMEX—New York Mercantile Exchange.
171. NYPP—Member Systems of the New York Power Pool (Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corp. and Power Authority of the State of New York).
172. Oglethorpe—Oglethorpe Power Corporation.
173. Ohio Commission—Public Utilities Commission of Ohio.
174. Oneok—Oneok Power Marketing.
175. Ontario IMO—Ontario Independent Electricity Market Operator.
176. Ontario Power—Ontario Power Generation Inc.
177. Oregon Office—Oregon Office of Energy.
178. Otter Tail—Otter Tail Power Company.
179. PacifiCorp—PacifiCorp.
180. PECO—PECO Energy Company and Horizon Energy.
181. Pennsylvania Commission—Pennsylvania Public Utility Commission.
182. PG&E—PG&E Corporation.
183. PGE—Portland General Electric Company.
184. PGP—Public Generating Pool.
185. PJM—PJM Interconnection, L.L.C.
186. PJM/NEPOOL Customers—PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition and Coalition of Midwest Transmission Customers.
187. Platte River—Platte River Power Authority.
188. PNGC—Pacific Northwest Generating Cooperative.
189. Powerex—British Columbia Power Exchange Corporation.
190. PP&L Companies—PP&L Inc., PP&L EnergyPlus Co., L.L.C., PP&L Montana, L.L.C.
191. PPC—Public Power Council.
192. Professor Hogan—Professor William W. Hogan.
193. Professor Joskow—Professor Paul L. Joskow.
194. Professor Koch—Professor Charles H. Koch, Jr.
195. Project Groups—Alliance for Affordable Energy, American Wind Energy Association, Center for Clean Air Policy, Center for Energy Efficiency and Renewable Technologies, Citizen Power, Inc., Citizens

for Pennsylvania's Future, Delaware Division of the Public Advocate, Environmental Law & Policy Center of the Midwest, Land & Water Fund of the Rockies, Legal Environmental Assistance Foundation, Minnesotans for an Energy-Efficient Economy, Natural Resources Defense Council, Northwest Energy Coalition, Office of the People's Counsel of the District of Columbia, Pace Energy Project, Pennsylvania Energy Project, Public Citizen, PJM Public Interest/Environmental User Group, Renew Wisconsin, Southern Environmental Law Center, Tennessee Valley Energy Reform Coalition, Union of Concerned Scientists, Wisconsin's Environmental Decade.

196. PSE&G—Public Service Electric and Gas Company.

197. PSNM—Public Service Company of New Mexico.

198. Public Citizen—Public Citizen.

199. Puget—Puget Sound Energy, Inc.

200. Rayburn—Rayburn Country Electric Cooperative, Inc.

201. RECA—Residential Electric Consumers Association.

202. Reliant—Reliant Energy, Incorporated.

203. RUS—Rural Utilities Service of the Department of Agriculture.

204. Salomon Smith Barney—Global Power Group of Salomon Smith Barney.

205. San Francisco—City and County of San Francisco.

206. SCE&G—South Carolina Electric & Gas Company.

207. Seattle—Seattle City Light Department.

208. SERC—Southeastern Electric Reliability Council.

209. Sierra Pacific—Sierra Pacific Resources, Inc.

210. Sithe—Sithe Energies, Inc.

211. SMUD—Sacramento Municipal Utility District.

212. Snohomish—Public Utility District No. 1 of Snohomish County, Washington.

213. SNWA—Southern Nevada Water Authority.

214. SoCal Cities—Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California.

215. SoCal Edison—Southern California Edison Company.

216. Sonat—Sonat Power Marketing, L.P.

217. South Carolina Authority—South Carolina Public Service Authority.

218. South Carolina Commission—Public Service Commission of South Carolina.

219. Southern Company—Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, GulfPower Company, Mississippi Power Company and Savannah Electric and Power Company.

220. SPP—Southwest Power Pool, Inc.

221. SPRA—Southwestern Power Resources Association.

222. SRP—Salt River Project Agricultural Improvement and Power District.

223. St. Joseph—St. Joseph Light & Power Company.

224. Statoil—Statoil Energy, Inc.

225. STDUG—Southwest Transmission Dependent Utility Group.

226. Steel Dynamics—Steel Dynamics, Inc.

227. Tacoma Power—City of Tacoma, Department of Public Utilities, Light Division.

228. Tallahassee—City of Tallahassee, Florida.

229. Tampa Electric—Tampa Electric Company.

230. TANC—Transmission Agency of Northern California.

231. TAPS—Transmission Access Policy Study Group.

232. TDU Systems—Alabama Electric Cooperative, Inc., Arkansas Electric Cooperative Corporation, Golden Spread Electric Cooperative, Kansas Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Seminole Electric Cooperative, Inc., and South Mississippi Electric Power Association.

233. Tennessee Authority—Tennessee Regulatory Authority.

234. TEP—Tucson Electric Power Company.

235. Texas Commission—Public Utility Commission of Texas.

236. Trans-Elect—Trans-Elect, Inc.

237. Transénergie—Transénergie.

238. Transmission ISO Participants—Baltimore Gas & Electric, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Energy Company, Conectiv, GPU Energy, Niagara Mohawk Power Company, Northeast Utilities Service Company, PECO Energy Company, PP&L, Inc., Potomac Electric Power Company, Public Service Electric and Gas Company, Vermont Electric Power Company, Inc.

239. Tri-State—Tri-State Generation and Transmission Association, Inc.

240. Turlock—Turlock Irrigation District.

241. TVA—Tennessee Valley Authority.

242. TXU Electric—TXU Electric Company.

243. UAMPS—Utah Associated Municipal Power Systems.

244. UMPA—Utah Municipal Power Agency.

245. United Illuminating—United Illuminating Company.

246. UtiliCorp—UtiliCorp United, Inc.

247. Utility Engineers—Utility Economic Engineers.

248. Vernon—City of Vernon, California.

249. Virginia Commission—Virginia State Corporation Commission.

250. Virginia Power—Virginia Electric and Power Company.

251. Washington Commission—Washington Utilities and Transportation Commission.

252. WEPCO—Wisconsin Electric Power Company.

253. WICF—Western Interconnection Coordination Forum.

254. Williams—Williams Companies, Inc.

255. Wisconsin Commission—Public Service Commission of Wisconsin.

256. Wolverine Cooperative—Wolverine Power Supply. Cooperative, Inc.

257. WPPI—Wisconsin Public Power, Inc.

258. WPSC—Wisconsin Public Service Corporation.

259. Wyoming Commission—Wyoming Public Service Commission.

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