Cyclic Limit without External Containment Shield

(c) Following one year after the effective date of this AD, operators cannot operate with a load compressor, P/N 3822270–5, installed, past 26,000 cycles unless they have installed an external load compressor containment shield.

Definition

(d) For the purpose of this AD, a shop visit is defined as when the APU is inducted into a shop for any reason.

Alternative Methods of Compliance

(e) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Los Angeles Aircraft Certification Office. Operators shall submit their request through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Los Angeles Aircraft Certification Office.

Note 5: Information concerning the existence of approved alternative methods of compliance with this airworthiness directive, if any, may be obtained from the Los Angeles Aircraft Certification Office.

Ferry Flights

(f) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Incorporation by Reference

(g) The actions required by this AD shall be done in accordance with the following AlliedSignal Inc. SBs: GTCP36–49–7471, dated April 20, 1999, GTCP36–49–7472, dated March 31, 1999, and GTCP36–49–7473, dated March 31, 1999. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Honeywell International, Inc., Attn: Data Distribution, M/S 64–3/2101–201, PO Box 29003, Phoenix, AZ 85038–9003; telephone 602–365–2493, fax 602–365–5577. Copies may be inspected at the FAA, New England Region, Office of the Regional Counsel, 12 New England Executive Park, Burlington, MA; or at the Office of the Federal Register, 800 North Capitol Street, NW, suite 700, Washington, DC.

(h) This amendment becomes effective on May 8, 2000.

Issued in Burlington, Massachusetts, on February 25, 2000.

Jay J. Pardee,

Manager, Engine and Propeller Directorate, Aircraft Certification Service.

[FR Doc. 00–5009 Filed 3–7–00; 8:45 am]

BILLING CODE 4910–13–U

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM99–2–001; Order No. 2000–A]

Regional Transmission Organizations

Issued February 25, 2000.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule; Order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) reaffirms its basic determinations in Order No. 2000 and clarifies certain terms. Order No. 2000 requires 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 Regional Transmission Organization (RTO). Order No. 2000 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: Changes to Order No. 2000 made in this order on rehearing will become effective on April 7, 2000.

FOR FURTHER INFORMATION CONTACT:
Alan Haymes (Technical Information), Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 219–2919
Brian R. Gish (Legal Information), Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, (202) 208–0996
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SUPPLEMENTARY INFORMATION:

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I. Introduction

On December 20, 1999, the Commission issued a Final Rule (Order No. 2000) to advance the formation of Regional Transmission Organizations (RTOs).[1] Our objective in promulgating Order No. 2000 was to have all transmission-owning entities in the Nation, including non-public utility entities, place their transmission facilities under the control of appropriate RTOs in a timely manner.

In Order No. 2000, the Commission concluded that regional institutions could address the operational and reliability issues confronting the industry, and eliminate undue discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility.

[1] Regional Transmission Organizations, Order No. 2000, 65 FR 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (2000).

Furthermore, we found that appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation. We stated our belief that appropriate RTOs can successfully address the existing impediments to efficient grid operation and competition and can consequently benefit consumers through lower electricity rates and a wider choice of services and service providers. In addition, substantial cost savings are likely to result from the formation of RTOs.

Order No. 2000 established 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

In the Final Rule, we noted that 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 did not propose a ''cookie cutter'' organizational format for regional transmission institutions or the establishment of fixed or specific regional boundaries under section 202(a) of the Federal Power Act (FPA).

We also established 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 future in terms of structure, operations, market support and geographic scope to meet market needs.

In addition, the Commission provided guidance on flexible transmission ratemaking that may be proposed by RTOs, including ratemaking treatments that address congestion pricing and performance-based regulation. The Commission stated that it would consider, on a case-by-case basis, innovative rates that may be appropriate for transmission facilities under RTO control.

Furthermore, to facilitate RTO formation in all regions of the Nation, the Final Rule outlined 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.

Lastly, under Order No. 2000, all public utilities that own, operate or control interstate transmission facilities must file with the Commission by October 15, 2000 (or January 15, 2001 [2]) a proposal to participate in an RTO with the minimum characteristics and functions to be operational by December 15, 2001, 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. That filing must explain the extent to which the transmission entity in which it proposes to participate 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.

II. Summary

Thirty-eight petitioners filed requests for rehearing and/or clarification of Order No. 2000.[3] These entities raise a variety of issues, including legal, policy and technical arguments. We respond herein to the arguments made to us in the requests for rehearing and clarification. To the extent not specifically addressed herein, the requests are denied.

Many of the parties requesting rehearing or clarification of Order No. 2000 express their agreement with the majority of the rule. Indeed, most petitions are relatively short in length and focus on only a few discrete issues, indicating that most parties are generally comfortable with the remaining substance of the Final Rule. We attribute this to the unprecedented outreach effort that the Commission undertook before and during the rulemaking process. Because we expect similar significant results from the post-rule collaborative process which we are initiating with our first regional workshop in Cincinnati on March 1, 2000, the Commission concluded that it was important to issue this order on rehearing before that date. Our order on rehearing focuses on the discrete issues that were raised on rehearing. However, the extensive background for this rulemaking and a comprehensive discussion of our goals and principles can be found in Order No. 2000.

On rehearing, we reaffirm the core elements and basic framework of Order No. 2000. However, we have provided clarification with respect to a number of issues, including concerns raised about our requirement that the RTO must have exclusive and independent authority under section 205 of the FPA to propose rates, terms and conditions of transmission service provided over the facilities it operates. While we have maintained the requirement without modification, we have carefully and comprehensively addressed the concerns that were raised and provided further clarification.

We have amended the regulatory text in three areas. First, we have revised the definition of market participant in section 35.34(b)(2) to remove specific references to entities that provide transmission service to an RTO. Second, we have added section 35.34(j)(1)(iv) to codify the requirement for audits with respect to the independence characteristic. Third, we have revised section 35.34(d)(4) to require RTO proposals to include an explanation of efforts made to include cooperatively-owned entities, in addition to public power entities, in the proposed RTO.

III. Discussion

A. Commission's Approach to RTO Formation

1. Voluntary Approach

In the Final Rule, the Commission adopted as a matter of policy a voluntary approach to RTO formation. In other words, Order No. 2000 does not mandate RTO participation. We concluded that a voluntary approach, with guidance and encouragement from the Commission, was the most appropriate to achieving RTO formation at this time.[4]

[2] 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.

[3] The requesters and abbreviations for them as used herein, are listed in an appendix to this order. PECO's request was filed one day beyond the thirty days allowed for rehearing requests, so we will consider its request to be for clarification. We note that TransConnect, Inc. filed a motion to intervene on January 27, 2000 raising no issues that warrant discussion herein.

[4] FERC Stats. & Regs. ¶ 31,089 at 31,033–34.

Rehearing Requests

The Pennsylvania Commission argues that RTO membership must be mandatory for all participants in the wholesale market and should be a condition of participating in the competitive market. It claims that failing to mandate participation undercuts the coordination of generation additions. It states that the Commission clearly perceived the problems, but stopped short of the solution.

TDU Systems asserts that the Commission did not give adequate consideration to the advantages of mandatory RTO participation and the disadvantages of the voluntary approach. It cites the potential costs associated with the innovative rates discussed in the Final Rule, and asserts that the Commission should perform a fuller evaluation of the potential costs and benefits associated with each approach.

TAPS argues that the Commission erred by relying on voluntary action for RTO formation rather than exercising its statutory authority to mandate RTOs. It states that the Commission violated its statutory obligations to remedy undue discrimination. It believes that past experience and common sense demonstrate that voluntary action, coupled with incentives, does not work.

CFA argues that the resistance of the vertically integrated incumbent network owners will be so vigorous that the voluntary approach will fail to solve the problem, and urges the Commission to mandate participation in RTOs.

In addition to the arguments in favor of a direct mandate, TDU Systems, TAPS, CFA, and Industrial Consumers argue that the Commission must generically condition the granting of all market-based rate authorizations and merger authorizations on participation in an RTO. CFA states, for example, that without participation in an RTO, allowing mergers or market-based rates is not in the public interest.

Commission Conclusion

We deny rehearing with respect to our adoption of a voluntary approach to RTO formation. We agree with those advocating a mandatory approach that the objective is to have all transmission-owning entities place their transmission facilities under the control of RTOs in a timely manner, and we stated this in the Final Rule.[5] There are, however, different possible means of attaining that objective. The Commission has made a judgment that the most efficient and effective means is one that involves establishing clear standards, removing obstacles, and fostering cooperation and creativity, rather than one that imposes strict mandates that could polarize parties and generate resistance. That we have not chosen to mandate RTO participation does not mean that we have avoided our obligations to address the impediments to competition that we identified; it merely means that we have chosen a method to address those impediments that we believe will efficiently achieve the result we desire.

We explained in the Final Rule that the voluntary approach as we structured it will allow the industry the opportunity and the flexibility to develop mutually agreeable regional arrangements, and will permit the industry to focus its efforts on the potential benefits of RTO formation rather than on a non-productive challenge to our legal authority to mandate RTO participation.[6] We also stated a number of reasons why we believe this voluntary approach will be successful: the pace of restructuring is accelerating, industry participants are recognizing the strategic benefits of focusing on one segment of the utility business, the Final Rule provides clear guidance on what is necessary to form RTOs, the Commission is facilitating a collaborative process, and certain favorable ratemaking treatments are offered to at least eliminate economic disincentives to RTO formation.[7]

Contrary to TDU Systems' assertion, the Commission gave careful consideration to the advantages and disadvantages of the voluntary and mandatory approaches. Specifically, TDU Systems faults the Commission for not quantifying the impact of the favorable ratemaking treatments that are offered, which, allegedly, would not be required under a mandatory approach. We do not believe it is appropriate to think of the innovative ratemaking treatments discussed in the Final Rule as a cost of the voluntary approach. As discussed in the Final Rule, the innovative ratemaking treatments are intended, among other things, to eliminate disincentives to the efficient use and expansion of regional transmission grids, and to allow transmission-owning utilities to capture some of the benefits of more efficient system operation.[8] We are requiring as a part of any proposal for innovative ratemaking treatments that the applicant demonstrate how the proposal would help achieve the goals of RTOs, to submit a cost-benefit analysis including rate impacts, and to demonstrate that the rate is just, reasonable and non-discriminatory.[9]

In response to those who argue that the Commission should state generically that all market-based rates and mergers must be conditioned on RTO participation, we continue to believe that this is best addressed on a case-by-case basis. We see no need to decide at this time that no merger or market-based rate proposal could satisfy our applicable standards without RTO participation. There will be sufficient opportunity to consider this in the context of individual cases.

2. Legal Authority

The Commission discussed in the Final Rule its legal authority with respect to RTO formation. We concluded that we possessed both general and specific authorities to advance voluntary RTO formation, and concluded that we possessed 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.[10] We discussed our authority and responsibility under sections 202(a), 203, 205, and 206 of the FPA.[11]

Rehearing Requests

TAPS argues that the Commission violated its statutory obligation to remedy undue discrimination by relying upon a voluntary, as opposed to mandatory, approach to RTO participation. CCEM argues that the Commission committed legal error by not adopting CCEM's proposal—operational unbundling of vertically integrated utilities that places all uses of the transmission system under the same tariff—as a remedy for undue discrimination. CCEM asserts that the Commission must provide a reasoned explanation why simply encouraging jurisdictional transmission owners to join RTOs is an effective remedy for undue discrimination.

Duke argues that the Commission should not make findings that it possesses the legal authority to mandate RTO participation on a case-by-case basis, and asks for rehearing of this conclusion, or, alternatively, requests clarification that no party will be deemed to have waived its right to challenge this conclusion in an individual proceeding. Similarly, EEI and Puget Sound ask for clarification that a public utility retains the right to

[5] *See id.* at 31,033.

[6] *Id.*

[7] *Id.* at 31,034.

[8] *Id.* at 31,171–73, 31,191–92.

[9] FERC Stats. & Regs. ¶ 31,089 at 31,196.

[10] *Id.* at 31,043.

[11] *See id.* at 31,043–46.

challenge the Commission's legal authority should the Commission seek to impose a requirement for RTO participation in the future. If the Commission does not so clarify, they seek rehearing.

ISO Participants argue that the Commission erred in finding that the formation of an RTO that involves transfer of operational control without a transfer of ownership is a transaction that requires approval under section 203 of the FPA. They assert that the assignment of operational responsibilities to an ISO, by itself, is not a disposition of facilities within the meaning of section 203.

Commission Conclusion

We found in the Final Rule that continuing opportunities for undue discrimination exist in the electric transmission industry and that they may not be remedied adequately by functional unbundling.[12] TAPS and CCEM believe that this finding requires a remedy different from the voluntary approach to RTO formation adopted in the Final Rule. TAPS asserts the remedy must be an RTO mandate, and CCEM asserts the remedy must be a total unbundling of transmission, including, apparently, retail unbundling. We do not agree that either of these remedies is required by law. While it is true that the Commission has a legal obligation to remedy undue discrimination it finds,[13] the Commission retains discretion as to what remedy to pursue.

As we said in the Final Rule, we believe that the use of RTOs throughout the country, with the required independence from market participants, can reduce opportunities for unduly discriminatory conduct.[14] The Commission has taken a large step in Order No. 2000 to encourage and advance the formation of RTOs. As discussed above with respect to the Commission's voluntary approach, the fact that the approach is not mandatory does not undermine the ultimate objective of widespread RTO formation. We believe that the approach we have taken is a measured and appropriate response at this time to the lingering discrimination concerns that have been raised.[15]

In response to those asking clarification of our conclusion in the Final Rule that the Commission possesses the authority to order RTO participation on a case-by-case basis to remedy undue discrimination or anticompetitive effects where supported by the record,[16] we note that this is a statement of our remedial authorities. It is well established that the Commission's discretion is at its zenith when fashioning remedies for undue discrimination.[17] The Commission is given substantial deference with respect to such remedies as long as they are reasonably tailored to meet the Commission's goals.[18] It is our view that, pursuant to sections 206 and 309 of the FPA, the Commission could order a public utility to participate in an RTO upon finding that the public utility was engaging in unjust, unreasonable, unduly discriminatory or anticompetitive practices, and that participation in an RTO was a reasonable remedy for that unlawful behavior. If we were to impose such a remedy in a particular case, any aggrieved party would have the right to challenge the lawfulness and reasonableness of that remedy to the extent permitted by law.

ISO Participants' argument that the Commission erred in its discussion of section 203 of the FPA is misplaced. Although they do not specify the particular language in the order that they object to, they apparently refer to our statement that ''public utilities'' transfers of control of jurisdictional transmission facilities to entities such as RTOs would require section 203 approval.'' [19] ISO Participants argue that a public utility's assignment of limited operating responsibilities to an ISO, while retaining physical control and ownership, is not a disposition within the meaning of section 203. The language in Order No. 2000 was a general summary statement of how the Commission has interpreted section 203 in its case precedent. Indeed, the Commission has invoked its section 203 authority over the transfers of control of transmission facilities for all five of the ISOs that have been approved thus far. Thus, our statement in Order No. 2000 was not intended as a new, changed, or amplified interpretation. Those questioning whether specific fact situations invoke our jurisdiction have appropriate avenues, such as requests for declaratory order, to have those questions resolved.

B. Minimum Characteristics of an RTO

1. Independence

In the Final Rule, we discussed how to ensure that an RTO would be able to operate independently from market participants. We defined who was a market participant. [20] We also discussed the extent to which ownership of a transmission company by market participants would be permitted. We stated that a truly passive form of ownership would be acceptable,[21] but that active ownership by market participants would be limited.[22] Another aspect of independence discussed in Order No. 2000 was how to ensure that the RTO could have independence with respect to its tariff. In response to comments on the NOPR, we clarified that the transmission owners retained rights to make section 205 filings to establish their revenue requirements for payments from the RTO, but that otherwise the RTO must have the authority to file any changes to its transmission tariff.[23]

a. Definition of Market Participant

We discuss below several distinct categories of rehearing requests with respect to our definition of market participant.

Rehearing Requests

Several requests for rehearing argue against our inclusion in the definition of market participant entities that provide transmission or ancillary services to the RTO. With respect to the inclusion of entities that provide transmission services, EEI, Independent Companies, Southern Company, United Illuminating and Conectiv are concerned that this could preclude the development of transcos and other for-profit RTOs. For example, Conectiv argues that the definition is circular when applied to RTOs that both own transmission facilities and provide transmission service. Conectiv requests the Commission clarify that the definition of market participant does not include transcos and other for-profit RTOs. Southern Company states that in the situation where an independent transmission company is an RTO, some might argue that the transmission company is providing transmission services to the RTO and would thus be a market participant. Southern Company also argues that an

[12] *Id.* at 31,015, 31,043.

[13] *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).

[14] FERC Stats. & Regs. ¶ 31,089 at 31,024.

[15] *See id.* at 31,028.

[16] *Id.* at 31,043.

[17] *See* Order 888, FERC Stats. & Regs. ¶ 31,036 at 31,676 (1996); Niagara Mohawk Power Corp. v. FPC, 379 F.2d 153, 159 (D.C. Cir. 1967); Tapoco, Inc., *et al.*, 39 FERC ¶ 61,363 at 62,169 (1987).

[18] Tenneco Gas Co. v. FERC, 969 F.2d 1187, 1198, 1201 (D.C. Cir. 1992).

[19] FERC Stats. & Regs. ¶ 31,089 at 31,045.

[20] FERC Stats. & Regs. ¶ 31,089 at 31,061–63.

[21] *Id.* at 31,064–68.

[22] *Id.* at 31,068–73.

[23] *Id.* at 31,075–76.

independent transmission company should not be a market participant where it participates in a larger RTO with other transmission owners and might be considered to be providing transmission services to the RTO.

EEI requests that the Commission clarify that an RTO is not a market participant with respect to transmission services it provides within the RTO's boundaries, and that an independent transco should not be deemed a market participant where it joins with others to form a larger RTO. Independent Companies ask the Commission to clarify that the market participant definition was not intended to include a transmission owner that is making its transmission facilities available through an RTO in which it holds active ownership and is not otherwise engaged in electric generation or marketing activities.

United Illuminating asserts that pure transmission owners do not have the incentive or ability to favor their power marketing activities, and they do not participate in the energy or ancillary services markets. United Illuminating also states that there appears to be no reason to include in the definition of market participant a transmission owner that provides transmission service to an RTO, because that service would be provided according to the protections of a regulated tariff. United Illuminating also claims that the part of the market participant definition that includes any entity whose economic or commercial interests that would be significantly affected by the RTO's actions or decisions would automatically preclude a transco as an RTO. United Illuminating asks that we confirm that pure transmission owners are not market participants.

Commission Conclusion

We will grant rehearing in part, and clarification, with respect to the definition of market participant. As noted in the Final Rule, we use the definition of market participant 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, when governance arrangements are being relied upon to ensure independence. With respect to the inclusion in the definition of any entity that ''provides transmission * * * services to the Regional Transmission Organization,'' [24] there is some confusion in what we intended. We did not intend that a ''pure transmission company'' [25] that qualified to *be* an RTO would be thought to be providing transmission services *to* the RTO within our definition of market participant. Additional issues may arise as to the fairness of an RTO's governance, however, where a pure transmission company is only one of several entities providing transmission services to or making transmission facilities available to the RTO. We now realize that our attempt to address these additional issues through the definition of market participant has caused unnecessary confusion. Accordingly, we will revise the definition of market participant at § 35.34(b)(2)(i) to delete specific references to entities that provide transmission services to the RTO.

While we are revising section 35.34(b)(2)(i) to drop specific references to entities that provide transmission services to the RTO in the definition of market participant, the involvement of a pure transmission company in RTO decisionmaking processes may be relevant to our independence criterion, and we cannot conclude that such involvement would never be problematic. For example, in the ISO context, we have set out the general principle that decisionmaking processes should be independent of any market participant or class of participants. The fact that a pure transmission company is no longer included in the definition of market participant does not mean that the governance of an ISO would be unaffected by the voting rights attributed to pure transmission companies (or, indeed, pure distribution companies who are also not included in the definition of market participants). Accordingly, we emphasize that our revision to the definition of market participant is not intended to prejudge the issues or considerations that may be raised with respect to governance arrangements involving, in part, pure transmission companies.

We note that pursuant to section 35.34(b)(2)(ii), the Commission can find on a case-by-case basis that an entity that has economic or commercial interests that would be significantly affected by the RTO is a market participant. As we stated in the Final Rule with respect to power buyers and with respect to pure distribution entities, there may be circumstances where a transmission entity that obtained a controlling interest in an RTO could manipulate access and curtailment decisions, or planning and expansion decisions, in a way that would advantage itself and disadvantage other users.[26] We can and will deal with those potential situations on a case-by-case basis.

United Illuminating makes the point that a pure transmission company that either is an RTO, or is part of an RTO, would likely have economic or commercial interests that would be significantly affected by the RTO's actions or decisions, thus making it fall within the definition of market participant under section 35.34(b)(2)(ii). We clarify that pure transmission companies will not be within the scope of section 35.34(b)(2)(ii) solely because of their ownership of transmission facilities.

Rehearing Requests

Several requests for rehearing also ask for clarification and/or rehearing with respect to the inclusion in the definition of market participant of entities that provide ancillary services to the RTO. EEI argues that there is a conflict between requiring the RTO to be the provider of last resort of ancillary services and including ancillary service providers in the definition of market participant. EEI states that this is a problem not only with RTOs that are transcos, but also where an ISO requires a transmission-owning member to provide ancillary services. EEI also asserts that the definition will interfere with an RTO's ability to run or administer an energy market. Independent Companies assert that the definition of market participant appropriately includes those entities providing generation-related ancillary services to the RTO, but should not be interpreted to include a transmission owner's provision of scheduling and dispatch services to the RTO.

Southern Company argues that an independent transmission company may find it beneficial to own limited amounts of generation to operate an effective and efficient transmission system, and that it should be allowed to own such ''non-competitive'' generation without being considered a market participant.

Commission Conclusion

With respect to the part of the market participant definition that encompasses an entity that provides ancillary services to the RTO, we offer a clarification. Order No. 2000 requires under Function 4 that an RTO serve as a provider of last resort of all ancillary services required by Order No. 888 and subsequent

[24] Section 35.34(b)(2)(i).

[25] We use the term ''pure transmission company'' to refer to a transmission company that owns transmission facilities but has no interests in or affiliation with sellers or brokers of electric energy.

[26] FERC Stats. & Regs. ¶ 31,089 at 31,062–63.

orders. As the provider of last resort for ancillary services, the RTO must ensure that adequate arrangements are in place for the provision of ancillary services to transmission customers. We recognize that there are many different ways that ancillary services can be made available, *e.g.* through contractual arrangements and market mechanisms. We did not intend that an RTO that was fulfilling its obligation to be a provider of last resort of ancillary services would be considered to be providing ancillary services to the RTO. Rather, that obligation is to provide ancillary services to the transmission customers. Accordingly, we clarify that an RTO that provides ancillary services within its region pursuant to its obligation under Function 4 will not itself be considered to be within the definition of market participant because of its performance of that function.

In addition, we clarify that our concern with the provision of ancillary services to the RTO is focused on generation-related ancillary services. Our concern, as we stated it in Order No. 2000, is that the RTO will likely have considerable discretion in defining the types and quantities of ancillary services needed and how they will be procured, and we did not want the suppliers of ancillary services to be able to influence the RTO's decisions on these issues.[27] We continue to believe this is a valid concern and will not delete this component of the market participant definition with respect to any generation-related ancillary service. However, we clarify that a pure transmission company that performs the ''Scheduling, System Control and Dispatch Service'' as described in Order No. 888 will not be considered to be within the section 35.34(b)(2)(i) definition of market participant because it performs that service.

In response to Southern Company's request that we allow independent transcos to own ''non-competitive'' generation that ''essentially'' provides a transmission function, we note that the definition of market participant is not framed in terms of generation ownership, but includes entities that sell or broker electric energy, or that provide ancillary services to the RTO. Any entity that sells or brokers electric energy, directly or through an affiliate, is a market participant. Also, as just discussed, any entity that provides generation-related ancillary services to the RTO or its customers is also a market participant.

[27] *Id.* at 31,062–63.

Rehearing Requests

TDU Systems objects to the Commission's statement in Order No. 2000 that retail suppliers of last resort may request to be excluded from the definition of market participant. TDU Systems argues that this should not be encouraged, because suppliers of last resort can retain substantial market share for a substantial period of time even if it does not overtly compete for retail sales business, and the pendency of waiver petitions at this time could be a source of disruption and confusion.

Commission Conclusion

We did not intend to encourage such requests for waivers, but at the same time, we feel compelled to recognize the possible situation where a distribution company may desire to exit the sales business and become a pure distribution company, but cannot due to an obligation to be the supplier of last resort under a state retail access program. We concluded that these entities would be within the definition of market participant, unless they could show us special factors as to why they should not (*e.g.* its sole electric sales are to satisfy a state requirement and it does not compete for retail load).[28] Certainly, any seller of electric energy will carry a substantial burden to prove to us that it should not be considered to be a market participant. We expect that this will apply to a relatively narrow class, and we should not be overwhelmed by waiver requests. Accordingly, we will not accept TDU Systems' request that we withdraw our statements in the Final Rule.

b. Ownership Issues

In the Final Rule, we discussed at some length the requirements we believed were necessary to ensure that ownership interests in RTOs would not jeopardize the independence of RTOs from market participants.[29] We concluded: that truly passive ownership interests by market participants would not be restricted; that active ownership by market participants would have to cease after five years (with an extension possible in certain circumstances); that during the time active ownership is permitted, up to five percent ownership by a single market participant was deemed a safe harbor and 15 percent ownership by a class of market participants was a benchmark; and that there would have to be periodic independent audits conducted to ensure independence.

[28] *Id.* at 31,063.

[29] FERC Stats. & Regs. ¶ 31,089 at 31,064–73.

We discuss below the requests for rehearing and clarification that we received on the issues of our limits on ownership generally, passive ownership, active ownership, and auditing requirements.

Rehearing Requests

Duke objects generally to the Commission's focus on ownership, asserting that the Commission's approach is overly rigid and that the Commission has not examined whether there are less restrictive means to meet the independence criterion. Duke first asks the Commission to reconsider the structure allowed for the natural gas industry, where affiliated production and marketing companies are permitted. Duke does not challenge the Commission's observation that the electric industry evidences a much higher level of vertical integration, but argues that there is no reason to require separation of control of transmission and merchant activities to a greater extent than is permitted in the gas industry. Duke also suggests that the Commission could allow affiliated transcos subject to a requirement that they retain an independent auditor to review the activities and decisions of the affiliated transco from the standpoint of potential discrimination and compliance with codes of conduct and file regular reports of its findings.

Conectiv asks that the Commission clarify that the ownership requirements do not apply to the non-profit ISO form of RTO, but would only apply to transcos and other for-profit entities with voting securities. It asserts that the record does not support ownership restrictions for non-profit RTOs.

Commission Conclusion

We do not agree that the structure currently in place for the gas industry would adequately support independent RTOs. As Duke itself notes, it would allow the senior management of an entity that operates in both the transmission and generation arenas to participate in decisions involving the transmission business. These decisions would, as a matter of course, have a significant effect on that same entity's generation business. We also disagree that independent auditing alone can substitute for the independence requirement. As we noted in the Final Rule, we have found that in the electric industry, it is difficult to monitor compliance with codes of conduct. Moreover, it is a very intrusive form of regulation and ultimately requires us to be ''chasing after conduct.'' As we noted in the Final Rule, this is not the light-handed regulation that is essential to support emerging competitive markets.

Conectiv's concern, which focuses at times on the distinction between for-profit and not-for-profit entities and at other times on the distinction between the transco and ISO form of RTO, is not entirely clear. We clarify that our concerns about ownership and control of an RTO are not a function of the for-profit or not-for-profit approach. The limits on ownership by market participants apply whenever the RTO intends to own and operate the transmission assets itself, either directly or indirectly through other entities. The fact that a market participant owner of an RTO operated on a non-profit basis would not, for example, preclude the possibility that the RTO could operate to benefit its generation business. Accordingly, ownership restrictions are appropriate in that case.

Rehearing Requests

With respect to passive ownership, NRECA, TDU Systems, and Dairyland argue that passive ownership should be disallowed completely after five years, except in extraordinary circumstances. NRECA, for example, recognizes the desirability of a transition period to phase out passive ownership, but asserts that the maintenance of a passive ownership threatens RTO independence and imposes heavy regulatory burdens on the Commission to police. TDU Systems argue also that passive ownership should be subject to the same benchmark individual and class limits that apply to active ownership.

New Orleans also challenges the allowance of passive ownership by market participants. New Orleans argues that the sale/leaseback cases and the Securities and Exchange Commission Rule cited in Order No. 2000 in support of allowing passive ownership are in fact much narrower than what the Commission is allowing, in that the passive owners there were not primarily in the business of selling electric power. By permitting passive ownership by market participants, New Orleans asserts, the Commission has not provided the safeguards that exist in other passive ownership situations. New Orleans claims that the Commission erred by not limiting passive the same way it limited active ownership. Finally, New Orleans asks that the Commission clarify that where there is clear evidence that an RTO proposal would not be *perceived* as independent by a majority of potentially affected entities, the proposal will be rejected.

Duke argues that if passive ownership restrictions are retained, the definition of passive ownership should not be so narrow as to leave the board and management of the passive owner without the capability to ensure that the transmission assets will be operated responsibly and in accordance with legitimate business objectives. Duke states that if it places its transmission into an affiliated transco, Duke's management should be able to participate in decisions that significantly affect the value of the transmission business, such as mergers, asset divestitures and acquisitions, and the choice of individuals to manage the transmission business.

EEI asks that the Commission clarify what types of passive ownership would be acceptable. Specifically, EEI requests that the Commission clarify that: (1) a fiduciary duty to maximize the value of the RTO's transmission assets will not defeat independence; and (2) passive owners may reserve certain rights to protect themselves against abuse by the holders of voting rights. EEI argues that a fiduciary duty to maximize transmission service revenues is similar to what the Commission has approved in the ISO context, and that there is no duty owed under corporate law that would require an RTO to maximize a passive owner's outside interests. EEI states that a duty to maximize the value of transmission assets will not create a bias toward transmission-only solutions, because of the RTO's obligations with respect to market mechanisms under the planning and congestion management functions. EEI argues further that passive owners should be able to reserve rights to participate in certain limited but major decisions that affect their ownership status, such as mergers and bankruptcy filings.

Commission Conclusion

We deny rehearing of the requests to phase-out or limit passive ownership beyond what we stated in the Final Rule. NRECA is correct that a phase-out of passive ownership, or limits on the percentage interests of passive ownership, would reduce the regulatory burdens of ensuring that the passive ownership arrangement does not threaten the RTO's independence. However, as we noted in the Final Rule, passive ownership arrangements can help resolve some significant impediments to the transition to the type of RTO that would both own and operate the transmission assets.[30] Permitting flexibility on these arrangements could enhance significantly our goal of accelerated formation of RTOs. Limits on passive ownership interests or required phase-outs would not further this goal. We are not convinced that the careful balance we reached on this issue in the Final Rule is in error.

New Orleans' concern that we should guard against passive ownership arrangements where there is clear evidence that an RTO proposal would not be perceived as independent echoes the concerns we expressed in the Final Rule.[31] We explained in the Final Rule that this requires assurances to all market participants that any passive ownership arrangement is truly passive and will not interfere with the independent operation and decisionmaking of the RTO. It is also one of the reasons we said that it was 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. We appreciate New Orleans' concerns that there are differences in the passive ownership arrangements that may be submitted as compared to those we may have evaluated before in the context of sale/leasebacks or those permitted under the SEC rule we referenced in the Final Rule. However, we referenced these only to make the point that there are different ways of structuring passive ownership arrangements and it may be possible to structure them in such a way to demonstrate that they are truly financial arrangements.

Duke's and EEI's concerns about the need of passive owners to protect the value of their assets and investments are valid. However, the Commission must balance these concerns against the need for an independent RTO. We expect that proponents of passive ownership arrangements will explore methods for protecting the value of their assets and investments while also maintaining the true independence of RTO decisionmaking. We recognize that this may require some creativity and innovation to meld the regulatory needs with those of the markets, but it is necessary if we are to ensure independent RTOs and accommodate passive ownership arrangements.[32]

In response to EEI's concerns, we do not expect that a fiduciary responsibility of the RTO to its passive owners to maximize the value of the RTO's

[30] FERC Stats. & Regs. ¶ 31,089 at 31,064.

[31] *Id.* at 31,065.

[32] *See, e.g.,* the statement of investment analyst Steven Fetter, who said, "The wide spectrum of permissible outcomes should be welcomed by Wall Street. What investment bankers do best is create innovative structures to meet legal and market requirements." *FERC's RTO Rule Should Cheer Investors,* www.fitchibca.com (January 13, 2000).

transmission assets would, by itself, be problematic with respect to the RTO's independence.

Rehearing Requests

On the issue of active ownership, Conectiv, CTA, EEI, Southern Company, and Alliance all argue that the Commission was wrong to sunset all active ownership after five years. EEI, representative of the others challenging the sunset requirement, states that it is aware of no other context where a complete ban on active ownership has been imposed to prevent control; that the sunset requirement conflicts with the Commission's finding that five percent active or lower does not raise control concerns; that five years is an arbitrary and capricious transition period; that limits on active ownership would reduce the numbers of bidders for a transco's stock and would limit investment opportunities for market participants; that a complete ban on active would be difficult to monitor since there is no existing requirement to disclose ownership less than five percent; and that the Commission does not have the legal authority to order divestiture of ownership by electric utilities. CTA adds that a five-percent active ownership should be indefinite, because other holders of active interests would prevent a five-percent minority holder from acting in its own interests. CTA states further that the five-year transition is too short and should be extended so as to avoid a ''fire sale'' in the event of an economic slowdown.

TDU Systems argue that the five-percent safe harbor for individual active ownership should be an absolute ceiling, and that the Commission should refuse to permit a market participant to propose a higher level. TDU Systems and NRECA both contend that intervenors should be allowed to challenge whether even a five-percent active ownership is too high. CTA asserts that passive ownership interests held by market participants should not be a factor in whether a market participant would be allowed to hold more than five-percent active ownership. It states that if the Commission is vigilant to assure that passive ownership cannot exercise control, there is no reason why passive ownership should be a factor in determining appropriate active ownership.

With respect to the 15 percent benchmark established in Order No. 2000 for a class of market participants, Conectiv, CTA, Alliance, and EEI argue that there should be no such benchmark. They assert that it is unlikely that class members would collude with their competitors, that there are existing laws to prohibit collusion, and that keeping track of the classes would be administratively difficult. EEI states further that such aggregation of interests is not a factor in any other regulatory context. Contrary to these parties' arguments, TDU Systems argues that a 15 percent benchmark for classes of active owners is too high, and that class ownership should be limited to 10 percent.

Commission Conclusion

We deny rehearing on the active ownership issues and reaffirm our decision that active ownership by market participants will have to cease after five years (with an extension possible in certain circumstances), and that during the time active ownership is permitted, up to five percent ownership by a single market participant will be deemed a safe harbor and 15 percent ownership by a class of market participants will be a benchmark. We carefully considered all of the extensive arguments made in the comments on the NOPR on the active ownership issue, and reached a solution in the Final Rule that we continue to believe appropriately balances the interests of all parties and our policy objective.

Many commenters argue that our willingness to allow active ownership for five years undermines our policy against active ownership after a five-year period. We disagree. Our decision reflects our belief that over the long term independence may be adequately assured only if there are no active ownership interests, but that a transition period during which active ownership in limited amounts may be proposed, together with auditing requirements, is a reasonable interim measure to assist RTO formation. With respect to the 15 percent benchmark for classes of active ownership, we explained fully in the Final Rule what are concerns are,[33] and we are not persuaded that our concerns are invalid. Moreover, we have permitted sufficient flexibility for parties to argue on a case-by-case basis that the 15 percent class benchmark is too high or too low.

Rehearing Requests

With respect to the independence audits required by Order No. 2000, Dynegy argues that the audits should commence immediately at RTO start-up, not be delayed for two years, and should be ongoing. Dynegy states that it has concerns about whether an audit performed two years after start-up is sufficient to guard against ownership abuses. Dynegy asks additionally that the Commission either place the audit and ownership requirements in the regulation or provide clarification as to why they do not appear in the regulations. TAPS expressly endorses the audit requirements as essential.

Commission Conclusion

No party has objected to having independent audit requirements for passive interests, active interests, and ISO governance, and we continue to believe they are essential. In response to Dynegy, it is of course a judgment as to how often to have them and how soon to start them. We note that the Final Rule provides for the first audit two years after our *approval* of the RTO, not after RTO start-up. We believe we have struck an appropriate balance among the goals of having a sufficient check on independence, allowing time for some initial operational shake-out, and not imposing overly burdensome procedures. We agree with Dynegy that it would be useful to state the auditing requirements in the text of the regulations, and we have therefore added a new sub-paragraph (iv) to section 35.34(j)(1) for this purpose. The new regulatory text we added reads as follows:

(iv)(A) The Regional Transmission Organization must provide:

(*1*) With respect to any Regional Transmission Organization in which market participants have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after approval of the Regional Transmission Organization, and every three years thereafter, unless otherwise provided by the Commission.

(*2*) With respect to any Regional Transmission Organization in which market participants have a role in the Regional Transmission Organization's decision making process but do not have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after its approval as a Regional Transmission Organization.

(B) The compliance audits under paragraph (j)(1)(iv)(A) of this section must be performed by auditors who are not affiliated with the Regional Transmission Organization or transmission facility owners that are members of the Regional Transmission Organization.

We also note that we stated in Order No. 2000 that applicants have a continuing obligation to inform the

[33] FERC Stats. & Regs. ¶ 31,089 at 31,072.

Commission of any changed circumstances regarding ownership.[34]

c. Section 205 Filing Rights

In the Final Rule, we attempted to balance our desire to ensure that the RTO have exclusive and independent authority over changes to its transmission tariff with the FPA section 205 rights of public utility transmission owners to seek rate changes.[35] We affirmed 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. However, we also clarified that the transmission-owning public utilities whose facilities are used by the RTO have the right to make section 205 filings to establish their revenue requirement and the level of payments for use of their facilities. We also stated that we would also entertain other approaches as long as they ensured the independent authority of the RTO and the ability of transmission owners to protect the level of the revenue needed to recover the costs of their facilities.

Rehearing Requests

A number of parties requested rehearing or clarification challenging our division of section 205 filing rights between the RTO and transmission-owning members of the RTO.[36] For example, EEI reflects most of the rehearing requests on this issue in arguing that the division violates the transmission owners' section 205 rights. EEI claims that it will jeopardize cost recovery for the transmission owners because it breaks the link between establishing the revenue requirement and establishing rate design, and it further breaks the link between the party responsible for establishing the revenue requirement and the party responsible for recovering it. EEI argues that the RTO might not have the same incentive to design rates to recover costs as the transmission owner would, and that the division is inconsistent with court and Commission precedent. EEI states that this division will discourage the voluntary participation in RTOs, and is in fact inconsistent with at least some of the ISOs approved to date.

Alliance contends that the Commission erred in determining that the RTO must have exclusive authority to propose changes in rates. In addition to similar arguments that EEI made about this unlawfully depriving public utilities of section 205 rights and increasing the risks for transmission owners, Alliance argues that it is a false premise that the RTO needs exclusive authority over rates. It states that Commission oversight of rates will provide a complete check on the ability of transmission owners to implement rate changes that would place them at a competitive advantage *vis-a-vis* other market participants.

Conectiv argues that the division of filing rights is inconsistent with the law (and could result in an unconstitutional taking of property), that the Commission has provided insufficient factual basis in the record to support its assertion that RTOs must have the authority to file rate changes in order to ensure independence from market participants, and that it does not provide sound economic and transmission policy. Conectiv states that a disinterested RTO might not make decisions based on the revenue recovery needs of the transmission owner, and that non-profit RTOs do not have incentives to file innovative rate design proposals to protect and encourage transmission investment. ISO Participants also assert that the division of authority is inconsistent with the Commission's endorsement of innovative rates.

Midwest ISO Participants ask the Commission to clarify that it need not modify its Commission-approved ISO documents on the issue of section 205 filing rights in order to qualify as an RTO. They state that the Midwest ISO Agreement carefully delineated the rights of the ISO and transmission owners, with the owners controlling the pricing structure and revenue distribution methodology. They assert that this was a critical element of the ISO Agreement, and the Commission explicitly stated in its order that it would honor the transmission owner's rights during the six-year transition period after start-up. Midwest ISO Participants contend that Order No. 2000's requirement that the RTO make section 205 filings to recover costs from transmission customers is at odds with the Midwest ISO owners' rights to control filings to change the ISO's rates. They claim further that Order No. 2000's division of authority makes no sense in the context of the Midwest ISO's tariff, which contains a rate formula. They request that the Commission make clear that the owners can continue to control the rate formula.

PECO asks for clarification of how the proposed division of filing authority would apply to situations like the PJM tariff, which is a combined ISO and transmission owner tariff. They claim that Order No. 2000 would effectively bar the PJM transmission owners from making changes to the tariff sheets that contain their individual revenue requirements. They ask the Commission to clarify that in such a case the transmission owners can still make section 205 filings to propose a change to the tariff pages that cover their revenue requirements. PECO also asks the Commission to clarify that any section 205 filing by an ISO type of RTO would be subject to the established ISO governance process.

SRP asks the Commission to clarify that its discussion of section 205 filing rights was not intended to broaden the applicability of section 205 to non-jurisdictional public power entities, and to clarify the ability of such non-jurisdictional entities to set the level of their revenue requirements. SRP wants the Commission to clarify that it intends to allow flexibility for non-jurisdictional entities to be able to set their revenue requirements through means other than making section 205 filings, which would mean in SRP's case, that its independent board could continue to set its revenue requirement.

Commission Conclusion

The Commission will deny rehearing of its decision that an RTO, in order to ensure its independence, must have the independent and exclusive right to make section 205 filings with respect to the transmission services the RTO provides to third parties. As discussed below, we reject arguments that this decision is inconsistent with law and precedent. However, in light of the concerns and misunderstandings raised, we also will further clarify our requirement.

As noted in Order No. 2000, and as evidenced by the comments of the parties seeking rehearing, unique issues arise with respect to tariff filing rights in the situation where the RTO operates and provides transmission service over transmission facilities owned by another entity, *e.g.*, in the context of an ISO. There are two legitimate concerns here that need to be balanced. One is the concern that for the RTO to provide transmission service independent from market participants, it must have independent control over its tariff, and not have a tariff that is subject to the control of particular participants in the RTO. The other concern is that of transmission owners who will turn the operation of their transmission facilities over to the RTO and need some assurance that they will continue to receive a fair return on their transmission investments. We

[34] *Id.* at 31,067, 31,072.

[35] *See id.* at 31,075–76.

[36] Conectiv, Duke, Southern Company, EEI, ISO Participants, United Illuminating, Transmission Owners of NY, AEP, PECO and Alliance.

reconciled those concerns in the Final Rule by stating that in the ISO type of situation, the RTO had to 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, but that transmission owners have the right to make section 205 filings to determine the appropriate payments for the RTO's use of their facilities.

As an initial matter, some parties question whether, to ensure independence, it is necessary for the RTO to have exclusive and independent authority with respect to filing changes to its tariff. We find the need to be clear. The tariff establishes the rates, terms, and conditions under which the RTO will provide transmission service to transmission customers. If the RTO does not have the independent right to seek appropriate changes to its tariff, it is difficult to see how that RTO could be viewed as providing a transmission service that is independent from market participants.

All of the objections to the division of authority we adopted in the Final Rule are based on the false premise that we are restricting the rights of transmission owners to protect their transmission investments and therefore jeopardizing their asserted right to recover their legitimate costs. This is not the case. Under our formulation, transmission owners may make section 205 filings at any time to establish their revenue requirements and the just and reasonable payments they may charge the RTO for use of their facilities. This gives them the full opportunity to recover their cost of service.

Those requesting rehearing, however, insist that transmission owners will be at risk for not recovering their allowed payments from the RTO, because the RTO either will not have an appropriate rate design or will not have the incentive to collect revenues from transmission customers sufficient to cover the payments to transmission owners. These arguments have no merit. There is nothing in the Final Rule that precludes transmission owners from seeking to assure recovery of their allowed payments from the RTO through appropriate mechanisms in the agreement establishing the RTO. For example, they may provide for a contractually enforceable obligation for the RTO to pay the owners their full revenue requirement as determined by the Commission, and they may even provide for some sort of true-up mechanism if an RTO fails to recover the costs it owes to the owners in a particular period.

In addition, nothing in the Final Rule precludes the transmission owners from participating in the RTO's designing of rates to transmission customers, as long as they are not given veto authority over, or otherwise control, what the RTO ultimately seeks to file under section 205. The Commission did not intend to preclude transmission owners from being involved in rate design proposals prior to the RTO filing them. If, in designing rules to establish a new RTO (or to justify rules of an existing ISO for which an RTO determination is sought), parties can establish an approach or process for involving the transmission owners in advance in the determination of the rate design proposals that the RTO will file, and can demonstrate that the approach or process does not compromise the independence of the RTO, the Commission will be open to such proposals.[37]

In addition, when the RTO proposes a rate design to recover the costs the RTO owes to the transmission owners as well as other costs that the RTO may incur, the Commission will exercise its responsibilities to approve a rate that is designed to recover all RTO costs, including the cost of payments that the RTO must make to the transmission owners. Transmission owners will be able to participate in that proceeding and to make whatever arguments they wish regarding appropriate rate design and the effect on their recovery of costs.

Most of the parties asserting legal challenges on this issue, including EEI, spend considerable effort reciting the basic rate changing mechanisms of section 205 of the FPA, and claim an inalienable right of a transmission owner to make rate changes even in the situation in which they no longer control the transmission facilities and are no longer the parties providing service over the facilities. They claim they are owed a ''guarantee'' of recovering the costs of the facilities which have been turned over to the RTO.

We reject the legal arguments made by those on rehearing. The Commission's holding in Order No. 2000 did nothing contrary to the fundamental tenets of section 205 of the FPA and nothing inconsistent with the rights of utilities to have the opportunity (as opposed to a ''guarantee'') to recover costs associated with facilities used to provide jurisdictional service. What the rehearing petitioners ignore, and what the Commission pointed out in Order No. 2000, is that in the context of an ISO, both the transmission owners and the RTO are public utilities under the FPA with respect to the same facilities. Further, it is the RTO, and *not* the transmission owners, that in this context is the provider (seller) of jurisdictional service. Because the RTO is providing the jurisdictional service, it is clearly within the parameters of section 205 for the RTO to have on file a rate schedule for the services it provides, and that it have the exclusive authority to propose changes to that rate schedule.[38]

Given that it deprives no public utility of the opportunity to recover its costs and earn a fair return on its investments, the section 205 filing procedure adopted in Order No. 2000 is well within the Commission's authority. The Supreme Court has stated that the Commission ''must be free, within the limitations imposed by pertinent constitutional and statutory commands, to devise methods of regulation capable of equitably reconciling diverse and conflicting interests.'' [39] That is what we have done here.

Several existing ISOs seek in their rehearings to have the Commission make specific findings with respect to their current division of section 205 filing rights. We do not believe it is appropriate to make such findings in this generic proceeding and instead will do so when those entities make their filings under this rule. We note that we stated in the Final Rule that we would entertain other approaches to the division of filing authority ''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.'' [40]

In response to SRP's request for clarification of the applicability of our finding to non-public utilities, we clarify that our discussion of filing rights pertained to public utilities under section 205 of the FPA and that it was not intended to broaden the applicability of section 205 to non-public utilities.

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[37] In this situation, parties may also consider providing for mutually agreeable rules regarding the timing of the revenue requirement and rate design filings.

[38] This is analogous to the situation in which there is a sale and leaseback of public utility property for financing purposes. In such a case, it is the lessee operator, not the owner, that files tariffs.

[39] Permian Basin Area Rate Cases, 390 U.S. 747, 767 (1967). The Supreme Court in this case also rejected the notion that there is an unrestricted right to file rate changes under section 4(d) of the Natural Gas Act, which is parallel to section 205(d) of the FPA. *Id.* at 779–80.

[40] FERC Stats. & Regs. ¶ 31,089 at 31,076.

In response to arguments that the Commission's decision will discourage the voluntary formation of RTOs or will result in favoring transcos over ISOs, the intent of this rule is to be neutral as to corporate form. As we stated above, we have left sufficient flexibility for transmission owners to protect their revenues, obligations to shareholders, and ability to attract capital whether they form an ISO, transco, or other form of institution.

Some parties have argued that our decision undermines the incentive to use performance based rates in the ISO context because it takes the development of such mechanisms out of the hands of the transmission owners. We do not think this is a necessary result. As we noted in the Final Rule, when activities that contribute to performance are shared between the RTO and the transmission owners, the RTO design may ensure that the rewards and penalties associated with activities performed by transmission owners flow through to the owners to achieve the desired result.[41]

2. Scope and Regional Configuration

Order No. 2000 set forth as the second minimum characteristic of an RTO that the RTO must serve a region of sufficient scope and configuration to permit it to maintain reliability, effectively perform its required functions, and support efficient and non-discriminatory power markets.

Rehearing Requests

The Pennsylvania Commission asks that the Commission ensure that RTOs are large enough to support an open and transparent market in reactive power and other ancillary services. It states that RTO applicants should be able to demonstrate that the geographic area and diversity of ownership of generation and transmission facilities is sufficient to support such a market.

Commission Conclusion

We agree with the Pennsylvania Commission that one of the considerations in evaluating scope and regional configuration is whether the RTO can support open and transparent markets, including ancillary service markets.

3. Short-Term Reliability

The Final Rule required as the fourth minimum characteristic of an RTO that the RTO have exclusive authority for maintaining the short-term reliability of the grid. As part of this characteristic, the Commission stated that the RTO must have exclusive authority for receiving, confirming, and implementing interchange schedules; must have the right to order redispatch of generation for reliability purposes; must have authority to approve transmission maintenance schedules; and must report to us if any reliability standards it operates under hinder it from providing reliable, non-discriminatory and efficiently priced transmission service. We did not require that the RTO have authority over generation maintenance schedules or that the RTO be required to establish transmission facility ratings. We also stated that on the issue of the extent of RTO liability relating to its reliability activities, we would address that on a case-by-case basis.[42]

Rehearing Requests

Dynegy and TAPS are concerned with the information received by control area operators who are market participants when they are directed to implement interchange schedules by the RTO. Dynegy agrees with the protections provided in the rule for separation of reliability personnel and wholesale merchant personnel, but asks the Commission to clarify that it will actively monitor compliance and enforce appropriate penalties for violations. TAPS objects to limiting the shield from sensitive interchange information to the control operator's wholesale merchant personnel. It states that this would allow for a market participant control area operator to share with its retail merchant function to take improper advantage of the commercially sensitive information. It asks that the Commission make clear that such information must be kept from all personnel involved with making purchases on the wholesale market, whether on behalf of wholesale or bundled retail customers.

Dynegy asks that the Commission clarify that to the extent a generator is redispatched by an RTO, it will be fully compensated for the redispatch order, which may include lost opportunity costs. Metropolitan asks that the Commission clarify that if an RTO reschedules or cancels planned transmission maintenance, the compensation will be limited to direct costs, and will not include indirect costs such as opportunity costs, because they are too speculative.

TAPS argues that certain functions that Order No. 2000 does not require the RTO to have for reliability purposes in fact should be required. TAPS contends that the RTO should be required to have a greater voice in transmission facility ratings in order to have control over ATC and TTC calculations. TAPS also contends that the RTO should have, at least for reliability reasons, control over generation maintenance schedules.

Duke calls the Commission's decision to decide liability responsibility on a case-by-case basis arbitrary and capricious. It states that transmission owners cannot be expected to transfer control of their facilities to what could be a non-profit RTO with limited assets without resolving the issue of the RTO's liability for its errors. Duke asks that the Commission clarify that it will not permit RTO operations to begin without a final resolution of liability issues, and that the RTO would not be given unilateral authority to alter the liability provisions of its tariff.

Commission Conclusion

We agree with Dynegy that it may be necessary to monitor and enforce compliance with the requirement for separation of reliability and merchant personnel. We expect that any RTO proposal would address this issue and propose appropriate and specific procedures concerning monitoring and enforcing compliance with all RTO rules, including these.

We share TAPS concerns that, when the retail merchant function is purchasing wholesale power, it is participating in the wholesale market and should not be privy to commercially sensitive information that would give it a competitive advantage over other purchasers of wholesale power. We expect that any RTO proposal will reflect these concerns to the extent it involves a control area operator affiliated with a market participant who could obtain access to commercially sensitive information.

We agree with Dynegy that generators that are redispatched by an RTO should be fully compensated and that the compensation would consider, among other things, lost opportunity costs. We also agree with Metropolitan that, when the RTO reschedules or cancels planned transmission maintenance, compensation to the transmission owners would be limited to the actual, verifiable out-of-pocket transmission-related costs incurred (*e.g.,* additional labor costs caused by the rescheduling).

In the Final Rule, we explained why we believe it is appropriate not to require, as an initial matter, that the RTO have authority over equipment ratings and generation maintenance schedules. While we expect that some RTO proposals may initially exceed our requirements or may evolve over time to place greater responsibility with the

[41] *Id.* at 31,184.

[42] FERC Stats. & Regs. ¶ 31,089 at 31,103–05.

RTO, we will not impose the additional requirements proposed by TAPS.

We continue to believe that liability issues should be addressed on a case-by-case basis. We agree with Duke that it is important that issues concerning liability and how liability provisions can or cannot be changed over time should be addressed during the collaboration process and resolved before the RTO begins operation. In this regard, a public utility can seek a declaratory order or make an RTO filing and have the liability issues resolved before the commencement of operations.

C. Minimum Functions of an RTO

1. Tariff Administration and Design

In the Final Rule, we adopted the requirement that the RTO must be the sole provider of transmission services and the sole administrator of its open access tariff.[43] Included in this function 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.

Rehearing Requests

Duke and EEI request clarification that the requirement that the RTO be the sole provider of all transmission service is not intended to require unbundling of non-jurisdictional transmission service. Duke argues that given the Commission's lack of jurisdiction over bundled retail transmission, the Commission has no power to indirectly require the unbundling of retail energy sales through a rulemaking. Duke proposes the following change to section 35.34(k)(1)(i): ''The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for *wholesale* transmission service.''

Dynegy also seeks clarification from the Commission as to the requirement that the RTO be the provider of transmission service. Dynegy requests guidance as to the level of flexibility contemplated by the Commission for this requirement in situations where an umbrella RTO-transco structure is adopted. Dynegy envisions a paradigm where an interconnection-wide entity determines and/or arbitrates questions of system capacity and acts a scheduler, but the RTO actually owns and maintains the facilities and performs the dispatch. Under this scenario, Dynegy points out that depending on the perspective, either entity can be the provider of transmission service. In addition, SoCal Edison requests clarification that a two-tariff model (*e.g.*, RTO/ISO tariff and transmission owner tariff), whereby transmission owners continue to sell transmission service that is provided by an RTO, is an acceptable option for RTOs.

In addition, a number of entities requested rehearing or clarification on an RTO's authority over interconnections to the grid. For example, Metropolitan and SoCal Edison request that the Commission modify Order No. 2000 to clarify that an RTO has no interconnection authority over transmission facilities it does not own or have operational control of. Metropolitan is concerned that some systems within an RTO region that are not under the operational control of the RTO are already subject to arrangements with adjoining control areas and transmission owners. In addition, Metropolitan notes that public power systems may not be able to resolve legal or tax concerns in order to permit their facilities to be controlled by an RTO.

SoCal Edison also argues that the Commission erred to the extent it provided RTOs sole authority to approve requests for interconnections. SoCal Edison notes that FERC, not RTOs, has the authority to approve and evaluate interconnections, pursuant to sections 202(a) and 210 of the FPA. SoCal Edison asserts that transmission owners must remain an integral part of the interconnection process. According to SoCal Edison, the text of the Final Rule should be amended as follows: ''The Regional Transmission Organization must have the authority to *establish interconnection policies and to coordinate the interconnection process* for new interconnections.''

EPSA asserts that the Commission failed to expound upon the role of RTOs *vis-a-vis* other transmission owners in facilitating new interconnections. According to EPSA, in order to ensure non-discriminatory interconnection processes for all generators, the Commission should establish the RTO as the lead agency for new interconnections, with individual transmission owners' roles limited to performing studies on behalf of the RTO. EPSA contends that the RTO must be capable, within a reasonable time frame, of performing the necessary transmission studies and analyses that are required with respect to requests for new interconnections. EPSA also argues that new generators should not be required to commit to a particular level or type of transmission service in order to obtain interconnection service. In addition, EPSA proposes the development of a standardized interconnection agreement that would hasten the development of new generation and streamline the interconnection process. EPSA argues that this application process for evaluating interconnection requests and for processing the requests must be applied in a consistent and non-discriminatory manner.

Dynegy supports the positions set forth by EPSA in its request for rehearing on this issue. Dynegy urges the Commission to require, at a minimum, that any RTO proposal clearly address the nature and scope of the RTO's responsibility for the interconnection of new generators to the transmission grid, and clarify that new generators will not be required to negotiate separately with both the RTO and individual transmission owners.

Finally, EEI requests that the Commission clarify that any RTO authority over new interconnections does not interfere with the right to recovery of costs of new interconnections under section 205 of the FPA.

Commission Conclusion

We will not revise section 35.34(k)(1)(i) as proposed by Duke to limit it to wholesale transmission service. The proposed revision would disable the RTO from performing those retail transmission services that are already included in our *pro forma* tariff, *i.e.,* unbundled retail transmission that may occur, voluntarily or as the result of state action, on the system of the historical bundled retail supplier, or unbundled retail transmission service provided by other transmission providers that constitute more remote segments of a multi-system transmission transaction.

However, we clarify that the Final Rule is not intended to require the unbundling of non-jurisdictional transmission service (*i.e.,* the transmission component of bundled retail sales of energy). That is, the requirement does not interfere in any way with whether retail open access and retail choice are provided, or with the pricing of retail bundled power sales which is a decision for appropriate state authorities. However, the requirement *is* intended to require that the RTO control all transmission facilities in the region. This is consistent with what the Commission has done with respect to ISOs in the past. As Duke notes, the Commission has addressed in the context of existing ISOs, issues surrounding the fact that a transmission owner's assets continue to be used to provide bundled retail power sales. For example, in *PJM,* the Commission noted that, when transmission owners engaged

[43] *See* FERC Stats. & Regs. ¶ 31,089 at 31,108.

in transactions under the PJM Tariff to meet retail load, they would be, at the same time, using their transmission system to make bundled retail sales and using the transmission system of the other transmission owners, *e.g.,* to import power to their system for the purpose of making bundled retail sales.[44] We note that, to date, according to one analysis,[45] approximately 40 percent of the nation's electricity sales to ultimate customers utilize transmission systems that are participating or have agreed to participate in Commission-approved ISOs without implicating the continuing jurisdiction of state commissions over bundled retail power sales. In short, we have accommodated ISOs that provide service at wholesale as well as at retail, and in states that have retail choice as well as states that do not have retail choice, and we have done so without a conflict between state and Federal authority.

In response to Dynegy's concerns, we do not see any inconsistency in our requirement that the RTO be the provider of transmission service and our flexibility to allow various RTO structures. We believe that some of this concern arises from the meaning of the term ''provider of transmission service.'' When we use the term provider of transmission service in this context, we are referring to the entity (*i.e.,* the RTO) that has the primary obligation to ensure that transmission service is provided, not the entity that may be operating the switches at the direction of the RTO.

In response to SoCal Edison's request for a clarification on the ''two-tariff'' model, it would be inappropriate to consider in the Final Rule the specifics of whether a particular aspect of an existing ISO arrangement would satisfy the RTO requirements. We emphasize, however, that we have created a Final Rule that provides clear guidance as to the RTO requirements and extensive flexibility in how to satisfy those requirements.

The concerns raised by Metropolitan and SoCal Edison with respect to an RTO's authority over interconnections to the grid have two facets. First, some facilities may not be under the control of the RTO because they are owned by an entity that has not placed any facilities under the control of the RTO, *e.g.,* a public power entity. We agree that the RTO would not have authority over interconnections to that portion of the grid. Second, some facilities may not be under the control of the RTO even though they are owned by an entity that has placed other facilities under the control of the RTO. For example, in the NEPOOL region, only Pool Transmission Facilities (PTF) were placed under the control of ISO–NE. However, ISO–NE nonetheless has authority over interconnections to non-PTF transmission facilities. We would expect similar arrangements to be part of any RTO proposal.

We disagree with SoCal Edison's point that RTOs can exercise no authority over interconnections because that authority resides only with the Commission under sections 202 and 210 of the FPA. An interconnection obligation is an element of transmission service and is already required to be provided under our *pro forma* tariff that will be administered by the RTO.[46] As EPSA notes, this is true, whether the interconnection request is tendered concurrently with a request for transmission service or in advance of a request for a specific transmission service.[47] It is therefore appropriate for the RTO to be the entity that reviews and approves interconnection requests. However, we agree with SoCal Edison that transmission owners must remain an integral part of the interconnection process. We also agree with Dynegy that new generators should not have to negotiate separately with the RTO and individual transmission owners. We expect one-stop shopping under any RTO.[48] Finally, we agree with EEI that the RTO's authority over new interconnections does not suggest that entities incurring costs to provide those interconnections will not be compensated.

2. Congestion Management

In the Final Rule, the Commission concluded that an RTO must ensure the development and operation of market mechanisms to manage congestion.[49] The market mechanisms must provide transmission customers with efficient price signals regarding the consequences of transmission use decisions. We asserted that these pricing proposals should ensure that (1) the generators 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. The Final Rule did not prescribe a specific congestion pricing mechanism; instead, RTOs have considerable flexibility to propose a congestion pricing method that is best suited to their circumstances.

Rehearing Requests

Dynegy argues that because congestion management is a ''hot'' topic, the Commission should hold a technical conference on issues surrounding congestion management and RTOs.

TDU Systems requests clarification that the Commission has not mandated or approved the auction of limited transmission capacity to the highest bidder in all circumstances. TDU Systems asks whether the market participant who can pay the most for the capacity is necessarily the one who will maximize the overall societal benefits of obtaining it and whether the entity that can afford to pay the most on that day is the supplier who can pay the going rate specifically because it has decided to avoid serving loads of poorer residential consumers. TDU Systems state that, while they do not expect the Commission to have immediate answers to these questions, they urge the Commission to make clear that the subject remains open for discussion. TDU Systems contends that, otherwise, unfettered reliance on market mechanisms in transmission pricing may become a recipe for new forms of undue discrimination.

Commission Conclusion

We deny Dynegy's request, as part of this rehearing order, to direct a technical conference on congestion management issues. We agree that congestion management issues may be significant and controversial and expect that parties will use the collaboration process to tackle these issues.

As requested by TDU Systems, we confirm that Order No. 2000 does not mandate or pre-approve any particular form of market mechanism for congestion management. Furthermore, we agree that congestion pricing must satisfy the same standards as any other rate, term or condition of service, *i.e.,* just, reasonable, and not unduly discriminatory or preferential. We encourage that parties use the collaborative process to identify their concerns about congestion pricing.

3. Ancillary Services

In the Final Rule, the Commission concluded that an RTO must serve as the provider of last resort of all ancillary services required by Order No. 888 and

[44] Pennsylvania-New Jersey-Maryland Interconnection, L.L.C., 81 FERC ¶ 61,257 at 62,281–82 (1997).

[45] *See* Initial Comments of Edison Electric Institute on the RTO NOPR, at Appendix B.

[46] PJM Interconnection, L.L.C., 87 FERC ¶ 61,299 (1999), *reh'g denied,* 89 FERC ¶ 61,186 (1999).

[47] *See* Ameren Operating Companies, 89 FERC ¶ 61,041 (1999), *order on reh'g,* 89 FERC ¶ 61,208 (1999); Central Hudson Gas & Electric Corporation, *et al.,* 88 FERC ¶ 61,138 (1999).

[48] *See id.;* New England Power Pool, *et al.,* 87 FERC ¶ 61,043 (1999).

[49] FERC Stats. & Regs. ¶ 31,089 at 31,126.

subsequent orders.[50] The Commission also allowed RTOs to propose other ancillary services in recognition of local or regional conditions. Moreover, the Commission concluded that real-time balancing markets are essential for the development of competitive power markets and 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.

Rehearing Requests

Steel Dynamics requests rehearing of the Commission's decision not to establish standard definitions for energy imbalance services, and requests a determination that an hourly assessment of such imbalances is the proper standard for FERC-approved ancillary services. In the alternative, Steel Dynamics requests that the Commission establish a generic proceeding to provide guidance on the development of real-time energy imbalance markets and energy imbalance services.

On rehearing, TDU Systems argues that backup and hour-to-hour load following service should be added to the mandatory ancillary services menu. In the alternative, TDU Systems requests that the Commission: (1) Clarify that proposals to augment the Order No. 888 menu of ancillary services offerings are appropriate subjects for negotiation during the collaborative process; (2) clarify that the Commission will entertain proposals by market participants as well as RTOs to augment the menu of RTO ancillary services, whatever the outcome of the regional process; and (3) clarify that additional ancillary services may be proposed on bases other than local or regional conditions.

Duke seeks clarification that in the discussion of balancing the Commission was not referring to inadvertent interchange. Duke notes that inadvertent interchange is the integration of all of the mismatches within a control area over a time period, typically a single hour, while energy and generation imbalances are the integration of a particular transmission customer's load mismatches for any particular scheduled transmission.

EEI requests that the Commission provide congruence in the deadlines for the deployment of both congestion management and real-time balancing markets, a year after an RTO commences initial operation. EEI argues that real-time information is needed to operate a real-time balancing market and this information requires investment and installation of metering equipment. In addition, EEI notes that operating a real-time balancing market encompasses full coordination across interconnections.

Commission Conclusion

We deny the request to establish a generic proceeding to provide guidance on the development of real-time energy imbalance markets and energy imbalance services. We agree with Steel Dynamics that these issues may be significant and controversial and expect parties to use the collaboration process to address these issues.

We also decline to mandate additional ancillary services as part of this Final Rule, but we clarify that proposals for the RTO to offer additional services is an appropriate topic for discussion during the collaborative process. We expect that one of the benefits of RTOs is that they will be responsive to the needs of transmission users and consider additional services beyond those mandated in Order No. 888 for service on an individual system basis. While market participants are free to propose revisions to RTO proposals that are ultimately filed with the Commission, it is preferable that these issues be thoroughly raised and considered during the collaborative process.

We clarify that the RTO's responsibility for operating a balancing market is intended to address the energy and generation imbalances that are associated with customers' transactions. However, we did express our concern that transmission users had unequal access to balancing options depending on whether they also operate a control area. We recognize that inadvertent interchange among control areas is intended to address different operational matters, but there is some concern among industry participants that control area operators have the ability to use inadvertent interchange as a low cost source of energy imbalance service.[51]

We are not persuaded by EEI that we should extend the deadline for real-time balancing markets. We understand that such markets may require technological support and investment in metering equipment, but we believe that these issues can be resolved within the current deadline.

4. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)

The Final Rule provides that the RTO must independently calculate ATC and TTC values based on data developed partially or totally by the RTO. When data are supplied by others, the Final Rule stated that the RTO must create a system of checks and tests to ensure unbiased data and coordination. Also, the Commission concluded that issues relating to capacity benefit margin (CBM) were outside the scope of this proceeding and we noted that CBM issues can be addressed in Docket No. EL99–46–000.

Rehearing Requests

Conectiv requests clarification that a non-profit ISO, which is an RTO, shall accept equipment ratings and other verifiable transmission data from member transmission owners to be used in the calculation of ATC and TTC values. Conectiv is concerned that an RTO may deny the use of verifiable data such as equipment ratings and impose its own different standard. According to Conectiv, the non-use of transmission owners' verifiable data, such as equipment ratings by an RTO, may influence transmission investment and levels of reliability on the transmission owners' systems.

TAPS argues that the Commission should clarify that RTOs have the authority to independently review, verify and modify CBM in setting ATC and TTC with the RTO's CBM values controlling pending ADR. TAPS asserts that CBM is a key component that goes into the computation of ATC and failure to include CBM within RTO authority will make RTO authority over ATC meaningless.

Commission Conclusion

In the Final Rule, we concluded that the RTO should calculate ATC/TTC values based on data developed partially or totally by the RTO. In addition, the Commission required that RTOs independently verify data supplied by transmission owners for the calculation of ATC/TTC. Accordingly, we agree with Conectiv that an RTO can rely on data provided by the transmission owner provided that the data is verifiable by the RTO.

In response to TAPS, we recognize that CBM is an important component in calculating ATC. However, as noted in the Final Rule, issues relating to CBM are too detailed to be addressed at this time and should be addressed when RTO proposals are filed. We agree that these issues need to be resolved because

[50] *See* FERC Stats. & Regs. ¶ 31,089 at 31,140.

[51] We note that NERC is currently evaluating issues related to inadvertent interchange practices and the economic incentives of operating a control area as a source of low cost balancing options. *See* Report to Board of Trustees (Feb. 7–8, 2000).

the RTO cannot accurately compute ATC without also resolving CBM issues.

5. Market Monitoring

In the Final Rule, the Commission concluded that market monitoring is an important tool for ensuring that markets within RTOs do not result in transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power. In section 35.34(k)(6) of the regulatory text, we outlined the minimum standards that RTOs' market monitoring plans must satisfy. We also provided latitude to the RTO and market participants to design a market monitoring plan that best fits the circumstances of the RTO and the structure and design of its power markets. In addition, the Final Rule requires than an RTO propose an objective market monitoring plan to assess whether the RTO's involvement in markets favors its own economic interest.[52]

Rehearing Requests

PSE&G reiterates the concerns it raised in its NOPR comments about the need for and extent of a market-monitoring function for RTOs, and asks that it be eliminated as one of the RTO's functions. PSE&G also notes that, while the Final Rule declined to sunset the market monitoring function as PSE&G had proposed, it noted that as bulk power markets evolve and become more competitive, we may revisit the need for the type of monitoring the Rule requires. Pointing to this observation, PSE&G proposes that the Commission at least amend the regulation to allow the market participants the flexibility to evolve to a more competitive state where the intrusion of a market monitor is no longer necessary. To this end, PSE&G proposes the following language to section 35.34(k)(6): ''(iv) The market monitoring plan may provide for its automatic expiration within a fixed period of time, provided that the Commission finds that the markets administered by the RTO are operating competitively without regulatory supervision.''

Conectiv argues that the Commission erred in giving the authority to remedy market power abuses to RTOs. Instead, Conectiv asserts that RTOs should be limited to investigating and reporting market power abuses. Conectiv is concerned that if an RTO is permitted to take an enforcement role in punishing market power abuses, the RTO might create anticompetitive effects in the market by discriminating in punishments. Duke expresses the same concerns as Conectiv and argues that the monitoring arm of RTOs should not be provided policing authority over market participants. Duke contends that an RTO should only be permitted to administer penalties and sanctions to which parties have voluntarily agreed by contract with the RTO.

Dynegy continues to be concerned that RTOs are market participants and therefore, Dynegy requests that the Commission clarify that the market monitoring plans proposed by RTOs must include a plan to assess whether the RTO is able to favor its own interests over those of its customers or members via its involvement in markets in which it participates. Furthermore, Dynegy requests clarification that an objective market monitoring plan to assess an RTO's own involvement must be performed by an independent auditor.

PP&L requests rehearing of the Commission's decision to expand the role of RTO market monitoring to the investigation and determination of individual market participant behavior. PP&L argues that the Commission's responsibility to identify and address the existence and exercise of market power and other anticompetitive activity may not be delegated to private parties such as RTOs. PP&L asserts that the FPA contains no authority for the Commission to delegate to private parties the enforcement of Commission's obligations to prevent discrimination and to regulate the public interest, and furthermore, the delegation of investigatory and regulatory authority to private parties is disfavored under Federal law.

EEI requests that the Commission require that market monitoring plans evolve as market structures evolve and mature. EEI recommends that the Commission reconsider the need for a process through which each RTO and its market participants can regularly assess the scope of market monitoring, the responsibilities of the monitoring unit and the types of data and information that are necessary to effectively monitor.

Commission Conclusion

For the reasons given in the Final Rule, we reject PSE&G's request to eliminate the market monitoring function completely. We also reject PSE&G's proposed modification to the market monitoring requirement. While we agree with PSE&G that the market monitoring function may change over time, it would be premature to assume, as PSE&G proposes, that parties can now predict that, by a date certain, all market monitoring functions should terminate. The Commission will periodically assess the need and degree of market monitoring that should be done by the RTOs. Accordingly, we agree with EEI that an important element of any market monitoring plan may be a process that provides for the periodic evaluation of the plan's design and effectiveness. We believe that this is an issue that should be raised during the collaborative process.

We believe that Conectiv's, Duke's, and PP&L's concerns about enforcement are premature and should be addressed when specific RTO proposals are developed and filed with the Commission.[53] We are not delegating our statutory authority and responsibility; however, we believe RTOs can help us understand and identify market problems. RTOs will be permitted to take actions only within specified parameters that are contained in a Commission-approved tariff.

We provide the clarification requested by Dynegy that the requirement referenced in the Final Rule[54] concerning a monitoring plan to assess the RTO's involvement in markets would be proposed at the same time as the market monitoring plan related to the markets the RTO operates and administers.

6. Planning and Expansion

The Commission concluded that the RTO must have ultimate responsibility for planning, and for directing or arranging, necessary transmission expansions, additions and upgrades within its region that will enable the RTO to provide efficient, reliable and non-discriminatory service. The Final Rule recognized the statutory authority of the states to regulate siting of transmission facilities and we concluded that the RTO's planning and expansion process must be designed to be consistent with state and local responsibilities. In addition, the Commission encouraged the development of multi-state agreements or compacts to review and approve new transmission facilities. Moreover, the Commission recognized that the planning and expansion function may require coordination among multiple parties and regulatory jurisdictions and established a three year deadline for satisfying this function.

Rehearing Requests

TDU Systems agree that transmission planning and expansion is a vital

[52] FERC Stats. & Regs. ¶ 31,089 at 31,064 and 31,156.

[53] *See* New York Independent System Operator, Inc., *et al.*, 89 FERC ¶ 61,196 (1999); New England Power Pool, 85 FERC ¶ 61,379 (1998).

[54] FERC Stats. & Regs. ¶ 31,089 at 31,156.

function for RTOs to perform, and on rehearing, TDU Systems argue that RTOs should be required to be capable of performing its planning and expansion responsibilities on the first day of RTO operation.

NY Transmission Owners seek three clarifications on planning and expansion issues: (1) Clarify that Order No. 2000 does not displace the legal rights of owners of the transmission assets, including the right to propose and build expansions to transmission systems to meet obligations under state law; (2) clarify that the Commission intends to require RTOs to adhere to the statutory requirements under FPA sections 210, 211 and 212 concerning any mandated interconnections or expansions, including statutory provisions respecting cost recovery; and (3) clarify that, if an RTO directs the construction of potentially uneconomic facilities, the transmission owners will not be required to bear the risk of any such facilities.

Duke notes that there may be situations where, regardless of the planning process used, and despite the best efforts of the RTO, transmission expansion cannot be effectuated. For example, Duke states that a state commission could choose not to participate in the multi-state process, or decide not to grant permission to construct. In these situations, Duke asserts that neither the Commission nor the RTO have legal or regulatory authority to compel the state commission to act in a different manner. Therefore, on rehearing, Duke asks that the Commission provide that in a situation in which, despite good-faith efforts by the RTO, certain transmission facilities cannot be built, the RTO consequently is relieved of the responsibility placed on it for directing or arranging necessary transmission additions and upgrades. Likewise, EEI asks that the Commission clarify that any obligation to upgrade or expand transmission is subject to good faith efforts to obtain the necessary approvals under federal, state or local law.

Commission Conclusion

We agree with TDU Systems that transmission planning and expansion are vital functions, but disagree that we can expect RTOs to be capable of performing these functions on the first day of RTO operation.

As we understand it, NY Transmission Owners are concerned on the one hand that they might not be compensated for any expansion that they undertake at the direction of the RTO, and on the other hand, that they might be precluded from expanding their systems on their own initiative without a directive by the RTO. We agree that a transmission owner is entitled to compensation for construction undertaken at the directive of an RTO, and we expect that these issues will be resolved systematically by the RTO. We also clarify that our Final Rule does not preclude a transmission owner from expanding its system on its own initiative; however, it would be prudent for the transmission owner in that case to resolve compensation issues in advance with the RTO.

In response to Duke, we clarify that the transmission expansion obligations are no greater than we established in the *pro forma* tariff.[55] States, of course, retain siting authority. However, among the benefits of an RTO is that expansion will reflect the result of a regional process that can involve regional regulatory authorities, and since the transmission system will be operated regionally, there may be more than one expansion alternative that could resolve the situation. We expect utilities to make good faith efforts to achieve the RTO's desired transmission expansion.

7. Interregional Coordination

In the Final Rule, the Commission added a general interregional coordination requirement as one of the minimum RTO functions.[56] Under this requirement, the RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions. The Final Rule envisioned some level of standardization and practices, including coordination and sharing of reliability data and data for TTC and ATC calculation, transmission reservation practices and congestion management.

Rehearing Requests

Dynegy requests expedited implementation of the interregional coordination function and proposes the creation of an interregional transmission system coordinator (ITSC) to accomplish the following functions:

(1) Resolving ''physics'' issues over broad geographic regions using flow-based modeling, thereby '' internalizing'' loop flow. This can be accomplished by:

• Expanding use of NERC's interchange distribution calculator (IDC) to determine and verify ATC calculations of existing transmission providers, whether they are individual utilities, ISOs or transcos and to determine and verify transfer capabilities at interfaces.

(2) Serving as a grid operations manager (similar to an air traffic controller).

The interregional transmission system coordinator could:

• Monitor and oversee the grid;
• Act as a seams coordinator;
• Serve as the Security Coordinator;
• Coordinate consistency of operating rules, *e.g.,* schedule deadline for submitting nominations;
• Oversee low-level market monitoring; and
• Enforce ATC and reliability rules

(3) Performing regional reliability functions on behalf of a Self-Regulatory Organization.[57]

Dynegy points out that the ITSC would not impinge on the majority of functions the Commission has assigned RTOs. Instead, Dynegy argues that the ITSC would complement RTOs by ensuring that ATC is calculated in a consistent manner or by ensuring tariffs and protocols do not conflict or cause unwanted market or reliability impacts.

Commission Conclusion

We will deny Dynegy's request for expedited implementation of the interregional coordination function. However, we continue to believe that the coordination of activities among regions is an important element in maintaining a reliable and efficient transmission system. We expect that the parties will use the collaborative process to discuss issues relating to interregional coordination and Dynegy's suggestions.

D. Open Architecture

In the Final Rule, we adopted the principle of open architecture in order that the RTO and its members have the flexibility to improve their organizations in the future. The Commission stated that an RTO must have the flexibility to unilaterally propose changes to its enabling agreements to meet changing market organization and policy needs.[58] We noted, however, that open architecture should not be interpreted to mean the unfettered ability for an RTO to modify its structure or processes. Under the Final Rule, proposed changes to the RTO's jurisdictional rate schedules and contracts will be subject to Commission review and approval under the FPA on a case-by-case basis.

Rehearing Requests

EEI states that transmission owners should have fundamental rights, such as

[55] *See, e.g., pro forma* tariff provisions at sections 15.4, 19.6, 20, and 28.2.

[56] FERC Stats. & Regs. ¶31,089 at 31,166–68.

[57] *See* Dynegy Request for Clarification and Rehearing at 13.

[58] *See* FERC Stats. & Regs. ¶ 31,089 at 31,170.

the right to terminate their participation in the RTO, the right to switch to another RTO, the right to merge RTOs, the right to recover their costs and a return on investment, and the right to protect their assets and employees from damages and injuries. EEI asks the Commission to clarify that these existing rights and obligations are recognizable and enforceable, and that the RTO should not be able to unilaterally abrogate these rights. NY Transmission Owners also request clarification that transmission owners' fundamental rights cannot be altered under the Final Rule's open architecture requirements. NY Transmission Owners are concerned that an RTO may be allowed to change the essential terms of the RTOs enabling agreements under the Final Rule's open architecture policy.

Commission Conclusion

On rehearing, some transmission owners restate their concern that open architecture places them at risk for being bound to an arrangement that is fundamentally different from the one they agreed to join. We believe that this is a legitimate concern that must be addressed in any RTO proposal. In addition, in the Final Rule we agreed that "the flexibility implied by open architecture should not be interpreted to mean unfettered ability on the part of the RTO to modify its structures or processes." [59] Accordingly, any RTO 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. All changes to an approved RTO will be examined on a case-by-case basis with interested parties having an opportunity to comment on any proposal. Open architecture is aimed at removing barriers to ongoing market improvements and is not intended to allow unilateral changes without a full airing of issues by all affected parties and review by the Commission.

E. Transmission Ratemaking

1. Pancaked Rates

The Final Rule noted that the elimination of pancaked rates within a region is a central goal of our RTO policy.[60] While it is acceptable to assess an access charge to recover capital costs, we stated that transmission customers should not be required to pay multiple access charges for crossing corporate utility boundaries in an RTO region.

Rehearing Requests

EEI contends that the Final Rule provides no analysis of the impact of the elimination of rate pancaking on wheeling rates and revenue. It argues that the policy ignores the impact of loop flows on transmission owners' property rights and infringes on state authority over service territory boundary setting. EEI goes on to suggest that the policy against pancaked rates be modified to allow an RTO to justify that its pancaked rates are just and reasonable.

Commission Conclusion

We deny rehearing of the Final Rule's policy prohibiting pancaked rates. Non-pancaked rates are a central attribute of RTO formation. We have found that pancaking of access charges acts as a major detriment to competition in the bulk power market. We believe that the allowance of transitional use of license plate rates and certain innovative rate provisions of the Final Rule will serve to protect transmission owners' property rights.

2. Uniform Access Charges

The Final Rule recognized that the pancaked rate prohibition can present problems for RTOs whose participants have divergent transmission cost structures.[61] An immediate move to a uniform access charge across the entire RTO could cause disruptive cost shifting among owners. We decided to apply flexibility in the use of license plate rates, echoing our approach in the ISO approvals to date. The Final Rule allowed RTO applicants to propose license plate rates for a fixed term of the applicant's choosing. Under Order No. 2000, license plate rates could be extended beyond the initial period if supported by the facts at that time.

Rehearing Requests

PSE&G complains that the Final Rule's policy on license plate rates is unfair to members of existing ISOs who will have to face uniform rates at a date certain established in the orders approving those ISOs. In light of the Final Rule's policy on license plate rates, PSE&G argues that PJM should be relieved of the requirement to file uniform access rates by July 1, 2002.[62]

TAPS contends that the policy on license plate rates should be amended to include an explicit requirement that all transmission owners be compensated for the use of their facilities.

Commission Conclusion

We deny rehearing of our policy on license plate rates. We shall not address in this rehearing order PSE&G's request that PJM be relieved of its obligation to file a uniform access charge by 2002. PJM's RTO compliance filing will be tendered well before that date and the Commission will consider any proposal to continue license plate rates proposed by the RTO as a whole in the context of the overall RTO proposal.

As to TAPS' request that we modify the Final Rule's license plate policy, we agree with TAPS that all transmission owners should be compensated for the use of their facilities, although we cannot conclude in this rehearing order what types of compensation methods should be used in a particular circumstance. As we stated in the Final Rule, a certain level of detail in ratemaking matters is beyond the Final Rule's scope, including issues such as TAPS' concern, and we will decide these issues on a case-by-case basis.[63]

3. Service to Transmission-Owning Utilities That Do Not Participate in an RTO

In the Final Rule, we stated that 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.[64] The Commission concluded that each proposal will be examined on a case-by-case basis. In addition, we noted that some transmission owners may face legal obstacles to RTO participation that need to be taken into account in the proposals.

Rehearing Requests

NRECA argues that the Commission should not unjustly reward RTOs by allowing them to charge higher rates to non-participants where such non-participation results from the RTOs' failure to reasonably accommodate the needs of non-participation during the RTO formation process. NRECA requests that the Commission clarify that proposals to charge individual system rates to a transmission customer who is a non-participant of the RTO may not be made unconditionally and must account for the reasons underlying non-participation. Dairyland also asserts that the Commission must make clear that non-public utilities will not be penalized through the imposition of

[59] FERC Stats. & Regs. ¶31,089 at 31,170.

[60] FERC Stats. & Regs. ¶31,089 at 31,174.

[61] *Id.* at 31,177.

[62] *See* Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶61,257 (1997).

[63] FERC Stats. & Regs. ¶31,089 at 31,177.

[64] *See id.* at 31,180.

disadvantageous pricing, terms and conditions for transmission service from an RTO if solutions to the barriers non-public utilities face in joining RTOs cannot be developed through the collaborative process.

Metropolitan, EEI, SMUD and NY Transmission Owners argue that the Commission erred in permitting RTOs to charge individual rates to a transmission customer who is a non-participating transmission owner in the RTO region and that this provision should be deleted. These entities assert that this aspect of the Final Rule violates prohibitions against undue discrimination embodied in the Commission's comparability pricing principles requiring that differences in rates be based on differences in costs incurred to provide service. In addition, EEI asserts that this provision contravenes the Commission's determination to pursue a voluntary approach for RTO formation. South Carolina Authority and TANC/MID also argue that the Commission should grant rehearing and amend the Final Rule to prohibit discriminatory rates for utilities that do not join RTOs. South Carolina Authority asserts that because the Commission lacks the authority to require RTO participation directly, subjecting parties who do not participate in an RTO to less favorable rates, terms and conditions of service would be unlawfully discriminatory. TANC/MID contends that the Commission failed to adequately explain its decision to permit RTOs to propose rates that penalize non-participants.

Commission Conclusion

As we noted in the Final Rule, proposals to charge different rates to non-RTO participants must be demonstrated to be just and reasonable. We agree that such demonstration must account for the reasons underlying non-participation including, among other things, impediments to participation that could not be overcome through the collaborative process. We do not agree with the premise of some of the petitioners who conclude that rate differences of any type constitute undue discrimination. Finally, we disagree that the fact that we will entertain such proposals is inconsistent with our voluntary approach to RTO formation. The Final Rule neither requires nor pre-approves this type of rate treatment. Rather, we simply declined to prohibit these types of rate proposals entirely.

4. Performance-Based Rate Regulation

The Final Rule invited RTO applicants to file voluntary performance-based regulation (PBR) proposals.[65] We provided guidance as to what constitutes a good PBR design in the RTO context. Under Order No. 2000, PBR plans can be filed subsequent to the filing or approval of the RTO proposal. The Commission concluded that proposals for PBR should be fully documented with the necessary information to evaluate costs and benefits.

Rehearing Requests

Industrial Consumers argue that the Commission does not have sufficient basis to abandon traditional cost-of-service principles in favor of PBR. They contend that the Commission may not have met legal requirements to enact such a policy shift. Further, Industrial Consumers complain that the Commission has not inquired sufficiently into the impact of PBR on customers of transmission service.

Commission Conclusion

As we noted in the Final Rule, we are not abandoning the fundamental underpinnings of our traditional transmission pricing policies, *i.e.,* that transmission prices must reflect costs of transmission service.[66] The fact that performance-based pricing mechanisms rely, in part, on benchmarks other than the transmission provider's own costs (*e.g.,* industry performance indices or normative goals) does not constitute a departure from cost-of-service principles. Moreover, we have not in the Final Rule approved any specific PBR. Any entity proposing a PBR mechanism would have to include in its request, as required by section 35.34(e)(1), explanations of how the rate would help achieve the goals of RTOs, including efficient use of and investment in the transmission system and reliability benefits to consumers; a cost-benefit analysis including rate impacts, and why the rate treatment is appropriate for the RTO. The Final Rule also discussed a number of principles relating to PBR design.[67] We will analyze the merits of specific PBR mechanisms when they are proposed.

5. Other RTO Transmission Ratemaking Reforms

a. Levelized Rates

One of the innovative rate options we discussed in the Final Rule is flexibility in the use of levelized rates to recover the cost of transmission assets. Commission policy does not normally allow changes from non-levelized to levelized rates when customer rates are impacted. The Final Rule allowed more flexibility in the use of levelized rates in RTO tariffs.[68] We believed that this flexibility is reasonable because the rates will be offered in a restructured market and will represent a new service in many ways.

Rehearing Requests

Metropolitan, TANC/MID, NRECA and Dairyland argue that the Commission's policy on levelized rates for RTOs will double charge existing transmission customers who have been paying depreciation charges in existing rates. These entities take issue with Order No. 2000's determination that an RTO's transmission tariff would be for a new service to new customers. They claim that many existing customers would be forced to pay twice for the same facility.

EPSA suggests that the double charging of existing customers may be largely avoided by allowing levelized rates only on the net, depreciated plant costs.

TDU Systems argues that the policy in Order No. 2000 on levelized rates is arbitrary and capricious because the need for flexibility does not justify a policy change that would require existing customers to pay twice for the same investment. TDU Systems says that the Commission's policy in *Kentucky Utilities*[69] should be applied to RTO transmission rates.

Commission Conclusion

We deny rehearing of our use of increased flexibility in considering rates based on levelized recovery of capital costs. We disagree that our decision on levelized rates reflects a policy change. Our prior cases dealt with rates charged by a single utility for service over its system. The customers did not change and the service did not change materially over time. Under an RTO, customers will receive service over multiple systems at a single, non-pancaked rate. Different customers will be served by the multiple systems and different services will be provided. This is a material change that warrants appropriate transmission ratemaking reform.

Finally, we do not agree that allowing levelized rates constitutes the payment for the same facilities twice. We reaffirm the explanation for considering levelized rates set out in Order No. 2000.[70] Customers do not buy facilities; they buy service. Moreover, the notion

[65] FERC Stats. & Regs. ¶31,089 at 31,183.

[66] *Id.* at 31,173.

[67] *Id.* at 31,185.

[68] *See id.* at 31,193–94.

[69] 85 FERC ¶61,274 (1998).

[70] FERC Stats. & Regs. ¶31,089 at 31,193–94.

that any RTO customer who paid rates for past services based on the cost of facilities that now comprise a portion of the RTO grid is somehow entitled to RTO rates based on the same ratemaking treatments is not only unjustified, but also unworkable.

Going forward, customers will be paying rates for expanded and more flexible services at rates that, in total, are significantly lower than the rates offered under individual tariffs. Moreover, going forward, levelized rates have the beneficial effect of charging customers the same rates for use of the same system regardless of when they take service. The sweeping reorganization of the transmission grid that will occur as the result of the Commission's RTO initiative and the industry's own movement towards unbundling of the assets themselves is the best time to consider what type of rate treatments, going forward, will best serve the needs of competitive energy markets.

b. Return on Equity

Several of the innovative rate options in the Final Rule involve adjustments to the return on equity allowed in the calculation of transmission rates.[71] These options include: formulary rates, risk adjustments and rates of return that do not vary with changes in the capital structure. We offered these options because they remove some of the disincentives that may accompany joining an RTO, they recognize changes in risk involved in restructuring and they take some account of the changes in the industry that have an impact on owners' risk.

Rehearing Requests

NRECA and TDU Systems ask that the Commission clarify its position on the increased risk that RTOs will be expected to experience. They are concerned that the Commission may have prejudged the issue and determined that RTOs will experience greater risk entitling them to a higher rate of return. They ask the Commission to clarify that the Commission will assess the risk of each RTO based on evidence brought to bear on a case-by-case basis.

Industrial Consumers argue that the Commission cannot assume that participation in an RTO increases risks for transmission owners. On the contrary, they argue that evidence shows that risks involved in RTO participation and divested transmission operation will actually be lower. Industrial Consumers point to findings of the California Public Utilities Commission and commentaries of utility investment analysts to support its proposition. They state further that risks are lower for RTO participants because of the statutory requirement that regulators allow a reasonable rate of return, unbundling will shield transmission owners from prudence reviews on the generation side, and more competitive generation will reduce bypass opportunities.

Commission Conclusion

The Final Rule draws no conclusions about the risks of a transmission-only business. It simply observes that the uncertainty created during the restructuring transition may increase risk. We have not prejudged the risk issue, and that issue will be determined case-by-case.

c. Accelerated Depreciation and Incremental Pricing for New Transmission Investments

The Final Rule recognized that new transmission investment may need innovative rate treatment to make necessary enhancements viable in the RTO context. For that reason, we stated that we would consider proposals to allow accelerated depreciation of new transmission assets and proposals to charge incremental rates for new investment while charging embedded rates for existing investment.[72]

Rehearing Requests

TANC/MID claims that the Commission's willingness to consider accelerated depreciation and incremental pricing for new investment is arbitrary and capricious and is not supported by substantial evidence. It claims that transmission projects are impeded more by siting and environmental concerns than by inadequate financing. TANC/MID also argues that incremental pricing for new investment while applying average pricing for existing facilities violates the Commission's policy against ''and'' pricing.

TDU Systems disagrees with the Commission that accelerated depreciation and incremental pricing are needed for new transmission investment. It finds them unwarranted deviations from established pricing policy. If the Commission adopts such rate policies for RTOs, it should require that any affected new facilities be put out for competitive bid.

Commission Conclusion

With respect to accelerated depreciation for new transmission investment, as with the other innovative rate treatments discussed in the Final Rule, we did not guarantee that it would be allowed in every situation. Rather, we stated that we were willing to provide the flexibility to permit RTOs to propose non-traditional depreciation schedules. All such proposals will be required to be supported by the explanations and analyses set forth in section 35.34(e)(1). We do not believe that our willingness to consider such proposals is arbitrary and capricious.

We disagree that we have departed from our policy against ''and'' pricing. The form of ''and'' pricing that the Commission has prohibited is described in the Transmission Pricing Policy Statement.[73] There we addressed ''and'' pricing at the corporate level, *i.e.,* proposals by individual transmission providers to assess certain customers both an embedded cost rate and an incremental cost rate, while assessing only an embedded cost rate to their own uses of the transmission system. While the pricing proposals we will entertain for RTOs may combine elements of embedded cost rates and incremental cost rates, they do not constitute corporate ''and'' pricing. Indeed, we have already approved these rate forms for most existing ISOs, noting for example, that it is acceptable to charge both a non-pancaked access fee based on embedded costs and an incremental charge reflecting opportunity costs or expansion costs. Significantly, unlike the corporate ''and'' pricing prohibited under our Transmission Pricing Policy Statement, the objective of this pricing proposal is not to make the cost faced by one group of transmission users (*i.e.,* the wholesale customer) higher than another's (*i.e.,* native load). Rather, this type of pricing is intended to (1) reduce the cost of transmission over multiple utility systems in both constrained and unconstrained situations and (2) rely on congestion charges to provide a uniform price signal to all users in constrained situations.

We shall not dictate that an RTO put transmission projects out for competitive bid. As we noted in the Final Rule, the Commission will not mandate any specific approach in how an RTO satisfies the function of planning and expansion.[74]

[71] *Id.* at 31,192–93.

[72] *Id.* at 31,194.

[73] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Public Utilities Under the Federal Power Act, Policy Statement, FERC Stats. & Regs. ¶ 31,005 (1994), *clarified,* 71 FERC ¶ 61,195 (1995).

[74] FERC Stats. & Regs. ¶ 31,089 at 31,165.

d. Other Innovative Rate Issues

Rehearing petitions were filed on other innovative rate issues as described below.

Rehearing Requests

NRECA is concerned that some of the innovative rate proposals discussed in Order No. 2000 may produce rates significantly higher than the rates that would be approved under existing cost-of-service principles. NRECA asks that the Commission clarify that the reasonableness of innovative rates offered by an RTO must be measured against established cost of service principles.

EEI suggests that the innovative ratemaking treatments be extended to all transmission-owning public utilities, even to non-RTOs. TAPS contends that the Commission should require RTOs seeking rate incentives to make them available to entities, other than existing transmission owners, who are willing to invest in transmission.

SoCal Edison requests that the Commission clarify that transmission owners who participate in an ISO type of RTO may file for innovative rate treatments. SoCal Edison states that the language in the Final Rule seems to imply that only an RTO can seek innovative rate treatment. It contends that there is no rationale for precluding transmission owners from seeking innovative rates if the desired rate treatment otherwise comports with Order No. 2000's requirements. Further, it states that the ROE-based innovative rate treatments are more appropriate for the revenue requirement filing that can be made by transmission owners. Therefore, SoCal Edison asks the Commission to clarify that transmission owners as well as RTOs can seek innovative rate treatment.

Commission Conclusion

In response to NRECA, we reaffirm our statement in the Final Rule that the innovative rate treatments we have offered do not depart from cost of service principles, *i.e.,* that transmission prices must reflect the costs of providing the service.[75]

We reject EEI's request to extend the innovative rate treatments to public utilities that do not participate in RTOs. The Final Rule addresses RTOs; the innovative rate treatments discussed in the Final Rule must be justified in terms of how the proposed rate treatment would help achieve RTO goals.[76] It is outside the scope of this rulemaking to address the extent to which such innovative rate treatments could be justified in the absence of RTO benefits.

We agree with SoCal Edison that some of the ROE-based innovative rate treatments relate most directly to the revenue requirement and, in the ISO context, the transmission owner may be responsible for filing the revenue requirement under section 205 of the FPA. A proposed innovative ROE treatment for a transmission owner's revenue requirement can best be evaluated in the context of any other innovative rate treatments proposed for the RTO. In addition, the justification required by section 35.34(e) involves an evaluation of factors related to the RTO as a whole, not only the revenue requirement of an individual owner. The collaborative process provides an important opportunity for the parties to consider the procedures that will apply to the filing of innovative rate treatments.

6. Additional Ratemaking Issues

There were several ratemaking issues not discussed above that were introduced in the Final Rule and addressed in petitions for rehearing. In the Final Rule, we determined that these issues, while important, were at a level of detail that they were better considered in individual RTO proposals.[77]

Rehearing Requests

Duke asks for clarification as to how RTO development and operating costs will be recovered. Duke asserts that such costs can be quite high, and even though the Commission is apparently committed to allowing such reasonable costs in transmission rates, Duke is concerned about what happens if state regulators do not authorize charging such costs to bundled retail transmission customers. Duke seeks clarification that if certain non-jurisdictional customers cannot be charged, the Commission will allow wholesale and unbundled retail customers to bear all the costs.

TAPS suggests that the Commission should require RTOs seeking rate incentives to make them available to other market participants.

SoCal Cities requests that the Commission clarify our description of its position on time-differentiated rates[78] to state: ''Metropolitan and Cal DWR favor the use of time-of-use pricing or off-peak rates for transmission; SoCal Cities oppose any generalized requirement for time-differentiated transmission rates.''

Commission Conclusion

We decline to make any generic rulings, in the abstract, on the recovery of RTO development and operating costs. We do not agree that the benefits of RTOs flow only to wholesale markets. For example, retail suppliers will benefit by access to regional markets at non-pancaked rates under an RTO. However, we are cognizant that there may be limitations on the ability of transmission providers to provide for recovery of these costs from all retail ratepayers in the near-term. We encourage parties to raise these issues during the collaboration process and to involve state regulators and representatives of retail consumers in these discussions. We expect that any RTO proposal will address these matters.

In response to TAPS, there is nothing in our Final Rule that precludes an RTO from involving entities other than existing transmission owners in transmission expansion. Indeed, we expect that the innovative rate treatments we have adopted will provide greater flexibility to RTOs in ensuring timely and efficient expansion.

We accept SoCal Cities' clarification of its position.

7. Filing Procedures for Innovative Rate Proposals

As articulated in the Final Rule, the Commission will 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.[79] We also required that applicants 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, the Final Rule stated that 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.

Rehearing Requests

EEI and SoCal Edison argue that the Commission should eliminate the requirement of a cost-benefit analysis in order to receive innovative rates. These entities note that cost-benefit analyses

[75] *Id.* at 31,173.

[76] *Id.* at 31,172. *See also* section 35.34(e)(1)(i).

[77] FERC Stats. & Regs. ¶ 31,089 at 31,196.

[78] *Id.* at 31,195.

[79] *Id.* at 31,196.

are difficult to perform, speculative in nature, and are likely to result in expensive and time-consuming litigation of competing hypotheticals and models.

Alliance Companies contend that the choice of January 1, 2005 is arbitrary and capricious, and unlikely to accomplish the Commission's goal of encouraging voluntary formation of RTOs. Alliance Companies requests that the Commission eliminate the sunset provision, and permit transmission owner participants in an RTO to address these issues in their RTO applications. Likewise, EEI is concerned with the sunset provision of January 1, 2005. EEI asserts that the Commission should not sunset innovative rate methods, but review them on a case-by-case basis instead.

Commission Conclusion

We shall not eliminate the cost-benefit analysis requirement. Those urging us to consider the transmission rate reforms we adopted in the Final Rule argued that innovative rate treatments would create tangible benefits for electric markets. Moreover, we expect that an evaluation of the impacts of any proposed rate treatment on electric markets would be an integral part of the process that filing parties would undertake before selecting and filing a specific innovative rate treatment.

We disagree that our selection of the sunset date is arbitrary and capricious. As we noted in the Final Rule, the innovative rate treatments which are available for a limited time are appropriate during a transitional period only. The transition period we selected reflects a reasonable balance of the benefits to RTO formation provided by mechanisms such as a rate moratorium and the inability to rely on these mechanisms for an extended period of time.

F. Other Issues

1. Public Power and Cooperatives

The Final Rule concluded that a properly formed RTO should include all transmission owners in a specific region, including municipals, cooperatives, Federal Power Marketing Agencies, Tennessee Valley Authority and other state and local entities.[80] Section 35.34(d)(4) of the regulatory text required that an RTO proposal filed with the Commission include a description of ''efforts made to include public power entities in the proposed Regional Transmission Organization.''

[80] FERC Stats. & Regs. ¶ 31,089 at 31,200–02.

Rehearing Requests

NRECA and Dairyland seek clarification and revision of section 35.34(d)(4) of the regulatory text. These entities assert that the Commission inadvertently failed to include the term ''cooperatives'' in the regulatory text, while the corresponding text of the preamble repeatedly referred to public power entities and cooperatives separately.

East Texas Cooperatives assert that although the Final Rule directs RTOs to include public power and cooperatives in the planning process, it does not require RTOs to allow small transmission owners to place their facilities under the RTO tariff and recover a portion of their annual transmission revenue requirements through the RTO tariff. East Texas Cooperatives argue that it does little good to require RTOs to include cooperatives in the development process if the RTO may refuse to allow the cooperative to place its facilities under the RTO tariff and receive an allocation of revenue.

Commission Conclusion

As requested by NRECA and Dairyland, we clarify that section 35.34(d)(4) should include cooperatives consistent with the text of the preamble. In fact, our intent was for those proposing RTOs to consult with all non-public utility transmission owners in its region. We will revise section 35.34(d)(4) to read as follows, with the addition to the text underlined: ''Any proposal filed under this paragraph (d) must include an explanation of efforts made to include public power entities *and electric power cooperatives* in the proposed Regional Transmission Organization.''

In response to East Texas Cooperatives, the Commission explained in the Final Rule that participation by public power entities and cooperatives is vital to ensure that each RTO is appropriate in size and scope. We continue to expect public power entities and cooperatives to join RTOs and to participate fully in RTO formation and operation.[81] Furthermore, we agree that all transmission owners should be compensated for the use of their facilities, although we cannot conclude in this rehearing order what types of compensation methods should be used in a particular circumstance.

[81] While the filing requirements of section 35.34(c) apply only to public utilities, we will permit submittals by non-public utilities if they wish to inform the Commission of their views.

2. Existing Transmission Contracts

In the Final Rule, the Commission concluded it is not appropriate to order generic abrogation of existing transmission contracts at this time.[82] We adopted the measured approach of addressing the issue of existing transmission contracts on an RTO-by-RTO basis and we stated that each RTO can propose whatever contract reform is necessary. The Commission stated that its goal in review of existing transmission contracts 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.

Rehearing Requests

Metropolitan, PSE&G and TANC/MID request rehearing on this issue. Metropolitan and TANC/MID argue that the Commission failed to provide a reasonable explanation for encouraging RTOs to propose piecemeal abrogation of existing contracts and that this policy is a departure from Order No. 888. PSE&G asserts that the Commission erred in refusing to address treatment of existing contracts on a generic basis and that the Commission should allow existing contracts to remain in effect following the formation of an RTO.

Commission Conclusion

We clarify that Order No. 2000 did not order abrogation of existing transmission contracts. We continue to recognize that existing contracts represent negotiated agreements. However, this issue has arisen in every ISO filing tendered to date, and we intend to address the issue of existing transmission contracts on an RTO-by-RTO basis when it arises again. RTOs may propose whatever contract reform they conclude is necessary to convert from existing contracts to RTO service. The circumstances faced by each region may differ significantly and the likelihood that parties can reach agreement on how to resolve this issue is enhanced if they have the flexibility to design region-specific solutions. As we stated in the Final Rule: ''[O]ur 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.'' [83]

[82] FERC Stats. & Reg. ¶ 31,089 at 31,205.

[83] *Id.*

3. Lighter Handed Regulation

In the Final Rule, the Commission concluded that a properly structured RTO would reduce the need for Commission oversight and scrutiny, which would benefit both the industry and the Commission.[84] We stated that some degree of deference could be granted on certain issues to independent RTOs that have appropriate procedural mechanisms in place to ensure adequate representation of all viewpoints. In the Final Rule, the Commission noted that we cannot delineate the appropriate degree of deference, or on what issues. We believe, however, to the extent an issue can be resolved fairly within a region without Commission involvement, benefits accrue to all parties.

Rehearing Requests

Dynegy argues that the Commission's deference standard has the potential to confer broad unilateral powers on RTOs. Dynegy requests that the Commission: (1) clarify that if a party challenges the bona fides of an alleged consensus, the Commission will independently examine the facts and circumstances to determine if there was a true consensus; and (2) clarify that if an RTO seeks deference on the adoption of a particular rule, the Commission will ensure that the rule is promulgated in advance pursuant to appropriate internal procedures and subject to Commission review.

Commission Conclusion

At the outset, we note 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. We confirm that our purpose is not to rely solely on consensus as the basis for accepting RTO provisions. However, we intend to give considerable weight to those aspects of an RTO proposal that result from good faith efforts and an inclusive collaboration process. We encourage all parties to participate in the collaborative process and to consider the diverse interests and needs of the other participants. In this rehearing order, we will not dictate the procedures that RTOs must follow in adopting and promulgating rules. We expect, however, that these procedures will be clearly defined in any RTO proposal that is filed with the Commission.

[84] *Id.* at 31,027.

G. Implementation Issues

1. Filing Requirements

In the Final Rule, the Commission required 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.[85]

Rehearing Requests

NRECA notes that some entities (small utilities as defined by the Small Business Association and entities with only limited and discrete transmission facilities that do not form an integrated transmission grid) have been granted waivers of some of the requirements of Order Nos. 888 and 889. NRECA requests that the Commission clarify that utilities with such waivers also be granted waivers from the filings mandated by section 35.34(c). NRECA argues that the transmission facilities owned by a utility holding waivers from Order Nos. 888 and 889 are not critical to an RTO and that the costs associated with making the section 35.34(c) filing will exceed the benefits.

Commission Conclusion

We deny NRECA's request to waive the filing requirements of section 35.34(c) to entities that have been granted waivers from some of the requirements of Order Nos. 888 and 889. We note that the Final Rule only requires 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. In any filing explaining why they are not participating in an RTO, we will allow entities that previously have been granted waiver from some or all of the requirements of Order Nos. 888 and 889 to make an abbreviated filing.[86] However, we expect that all utilities, including those transmission-owning utilities that received waivers, will participate in the collaborative process. Moreover, during the collaborative process, we expect those utilities to consider their involvement in an RTO, *e.g.,* to ensure that formation of an RTO is not impaired by the exclusion of their limited transmission facilities.

[85] *See id.* at 31,226.

[86] We also clarify that we are not precluding such entities from participating in joint filings with other public utilities or having other public utilities file on their behalf.

2. Deadline for RTO Operation

In the Final Rule, the Commission retained 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 2004).[87]

Rehearing Requests

Duke is concerned that it will not be able to comply with the time schedule set forth in Order No. 2000 for formation of an RTO without infringing on state jurisdiction over retail electric service. Duke requests clarification that the timetables set forth in Order No. 2000 are merely benchmarks and that Commission will permit public utilities to transition to RTO membership in a manner that is coordinated with state retail service restructuring and unbundling. In addition, EEI argues that the time schedules for RTO implementation are unreasonable and unrealistic given the record of RTO formation to date. EEI requests that the Commission modify the time schedules consistent with the flexibility shown throughout the Final Rule and to reflect a reasonable timetable for the development and implementation of an RTO.

Commission Conclusion

We will deny EEI's request to modify the time schedules adopted in the Final Rule. We will also reject Duke's clarification that the RTO operational deadlines in the Final Rule are merely benchmarks. We continue to believe that the timetable for RTO formation and implementation established in the Final Rule is feasible and realistic. First, we note that all industry participants and the Commission have learned a great deal during the formation of the five ISOs under Commission jurisdiction and this knowledge should facilitate RTO formation. Second, the Final Rule provided flexibility that enables an RTO to satisfy the minimum characteristics and functions in a cost efficient manner. Moreover, we adopted a longer phase-in period for functions that may be difficult to establish, such as congestion management, parallel path flow measures, and transmission planning and expansion. In response to Duke, we stated in the Final Rule that ''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

[87] *See* FERC Stats. & Regs. ¶31,089 at 31,229.

directly 'push all of the buttons.' '' [88] In sum, we continue to think that the phased startup and other implementation deadlines are reasonable.

IV. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act requires rulemakings to either contain a description and analysis of the effect that a proposed or Final Rule will have on small entities or to contain a certification that the rule will not have a significant economic impact on a substantial number of small entities. In Order No. 2000, the Commission certified that the Final Rule would not impose a significant economic impact on a substantial number of small entities. No rehearing requests of Order No. 2000 were filed on this issue and the Commission finds no reason to alter its previous findings on this issue.

V. Public Reporting Burden and Information Collection Statement

Order No. 2000 contained an information collection statement that the Commission submitted to the Office of Management and Budget (OMB).[89] Given that this order on rehearing makes only minor revisions to Order No. 2000, OMB approval for this order will not be necessary. However, the Commission will send a copy of this order to OMB for informational purposes.

The information reporting requirements under this order are unchanged from those contained in Order No. 2000. 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].

VI. Effective Date and Congressional Notification

Changes to Order No. 2000 made in this order on rehearing will become effective on April 7, 2000.

[88] *See id.* at 31,229.

[89] The OMB control numbers for this collection of information are 1902–0096 and 1902–0082.

VII. 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, NE, Room 2A, Washington, DC 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.
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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 revising § 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 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;

(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 and electric power cooperatives 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.* Any 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; see 61 FR 21540, May 10, 1996), 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.

(iv)(A) The Regional Transmission Organization must provide:

(*1*) With respect to any Regional Transmission Organization in which market participants have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after approval of the Regional Transmission Organization, and every three years thereafter, unless otherwise provided by the Commission.

(*2*) With respect to any Regional Transmission Organization in which market participants have a role in the Regional Transmission Organization's decision making process but do not have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after its approval as a Regional Transmission Organization.

(B) The compliance audits under paragraph (j)(1)(iv)(A) of this section must be performed by auditors who are not affiliated with the Regional Transmission Organization or transmission facility owners that are members of the Regional Transmission Organization.

(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; see 61 FR 21540, May 10, 1996), 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) through (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 Petitioners

Abbreviation—Petitioner

1. AEP—American Electric Power System
2. Alliance Companies—American Electric Power Service Corporation, Consumers Energy Company, Detroit Edison Company, FirstEnergy Corp. and Virginia Electric and Power Company
3. CCEM—Coalition for a Competitive Electricity Market
4. CFA—Consumer Federation of America
5. Conectiv—Conectiv
6. CTA—Competitive Transmission Association, Inc.
7. Dairyland—Dairyland Power Cooperative
8. Duke—Duke Energy Corporation
9. Dynegy—Dynegy Inc.
10. 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.
11. EEI—Edison Electric Institute
12. Entergy—Entergy Services, Inc.
13. EPSA—Electric Power Supply Association
14. Independent Companies—New England Power Company, Montaup Electric Company, National Grid Group, plc, Jersey Central Power and Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Vermont Electric Power Company and NSTAR Services Company
15. Industrial Consumers—Electricity Consumers Resource Council, American Iron & Steel Institute and Chemical Manufactures Association
16. ISO Participants—Baltimore Gas and Electric Company, Conectiv, Consolidated Edison Company of New York, Inc., Northeast Utilities Service Company, PP&L,Inc., Potomac Electric Power Company, Public Service Electric and Gas Company
17. Metropolitan—Metropolitan Water District of Southern California
18. Midwest ISO Participants—Alliant Utilities, 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, Northern States Power Company, Southern Indiana Gas & Electric Company, Southern Illinois Power Cooperative, Wabash Valley Power Association, Inc. and Wisconsin Electric Power Company
19. New Orleans—Council of the City of New Orleans
20. NRECA—National Rural Electric Cooperative Association
21. PECO—PECO Energy Company
22. Pennsylvania Commission—Pennsylvania Public Utility Commission
23. PP&L Companies—PP&L, Inc., PP&L EnergyPlus Co., LLC and PP&L Montana, LLC
24. PSE&G—Public Service Electric and Gas Company
25. Puget Sound—Puget Sound Energy, Inc.
26. SMUD—Sacramento Municipal Utility District
27. Snohomish—Public Utility District No. 1 of Snohomish County, Washington
28. SoCal Cities—Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California
29. SoCal Edison—Southern California Edison Company
30. South Carolina Authority—South Carolina Public Service Authority
31. 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
32. SRP—Salt River Project Agricultural Improvement and Power District
33. Steel Dynamics—Steel Dynamics, Inc.
34. TANC/MID—Transmission Agency of Northern California/Modesto Irrigation District
35. TAPS—Transmission Access Policy Study Group
36. 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
37. Transmission Owners of NY—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 & Electric Corporation, Power Authority of the State of New York

38. United Illuminating—United Illuminating Company

[FR Doc. 00–5021 Filed 3–7–00; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 157

[Docket No. RM81–19–000]

Natural Gas Pipelines; Project Cost and Annual Limits

Issued February 7, 2000.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to the authority delegated by 18 CFR 375.308(x)(1), the Director of the Office of Energy Projects (OEP) computes and publishes the project cost and annual limits for natural gas pipelines blanket construction certificates for each calendar year.

EFFECTIVE DATE: January 1, 2000.

FOR FURTHER INFORMATION CONTACT: Michael J. McGehee, Division of Pipeline Certificates, (202) 208–2257.

Section 157.208(d) of the Commission's Regulations provides for project cost limits applicable to construction, acquisition, operation and miscellaneous rearrangement of facilities (Table I) authorized under the blanket certificate procedure (Order No. 234, 19 FERC ¶ 61,216). Section 157.215(a) specifies the calendar year dollar limit which may be expended on underground storage testing and development (Table II) authorized under the blanket certificate. Section 157.208(d) requires that the ''limits specified in Tables I and II shall be adjusted each calendar year to reflect the 'GDP implicit price deflator' published by the Department of Commerce for the previous calendar year.''

Pursuant to § 375.308(x)(1) of the Commission's Regulations, the authority for the publication of such cost limits, as adjusted for inflation, is delegated to the Director of the Office of Energy Projects. The cost limits for calendar year 1998, as published in Table I of § 157.208(d) and Table II of § 157.215(a), are hereby issued.

List of Subjects in 18 CFR Part 157

Administrative practice and procedure, Natural gas, Reporting and recordkeeping requirements.

Daniel M. Adamson,

Director, Office of Energy Projects.

Accordingly, 18 CFR Part 157 is amended as follows:

PART 157—[AMENDED]

1. The authority citation for part 157 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7352.

2. Table I in § 157.208(d) is revised to read as follows:

§ 157.208 Construction, acquisition, operation, and miscellaneous rearrangement of facilities.

* * * * *

(d) * * *

Year	Limit	
	Auto proj. cost limit (Col. 1)	Prior notice proj. cost limit (Col. 2)
1982	$4,200,000	$12,000,000
1983	4,500,000	12,800,000
1984	4,700,000	13,300,000
1985	4,900,000	13,800,000
1986	5,100,000	14,300,000
1987	5,200,000	14,700,000
1988	5,400,000	15,100,000
1989	5,600,000	15,600,000
1990	5,800,000	16,000,000
1991	6,000,000	16,700,000
1992	6,200,000	17,300,000
1993	6,400,000	17,700,000
1994	6,600,000	18,100,000
1995	6,700,000	18,400,000
1996	6,900,000	18,800,000
1997	7,000,000	19,200,000
1998	7,100,000	19,600,000
1999	7,200,000	19,800,000
2000	7,300,000	20,200,000

* * * * *

3. Table II in § 157.215(a)(5) is revised to read as follows:

§ 157.215 Underground storage testing and development.

(a) * * *

(5) * * *

TABLE II

Year	Limit
1982	$2,700,000
1983	2,900,000
1984	3,000,000
1985	3,100,000
1986	3,200,000
1987	3,300,000
1988	3,400,000
1989	3,500,000
1990	3,600,000
1991	3,800,000
1992	3,900,000
1993	4,000,000