the consolidated entities or through the payment of dividends or any similar distribution, or an unsecured advance or loan would be made to a stockholder, partner, sole proprietor, limited liability company member, employee or affiliate, such that the withdrawal, advance or loan would cause, on a net basis, a reduction in excess adjusted net capital (or, if the futures commission merchant is qualified to use the filing option available under § 1.10(h), excess net capital as defined in the rules of the Securities and Exchange Commission) of 30 percent or more, notice must be provided at least two business days prior to the withdrawal, advance or loan that would cause the reduction: *Provided, however,* That the provisions of paragraphs (g)(1) and (g)(2) of this section do not apply to any futures or securities transaction in the ordinary course of business between a futures commission merchant and any affiliate where the futures commission merchant makes payment to or on behalf of such affiliate for such transaction and then receives payment from such affiliate for such transaction within two business days from the date of the transaction.

* * * * *

■ 3. Section 1.17 is amended by revising paragraph (d)(1) introductory text; adding paragraph (d)(1)(ii)(D); revising paragraph (e) introductory text; and adding paragraph (g), to read as follows:

§ 1.17 Minimum financial requirements for futures commission merchants and introducing brokers.

* * * * *

(d) * * *

(1) Equity capital means a satisfactory subordination agreement entered into by a partner or stockholder or limited liability company member which has an initial term of at least 3 years and has a remaining term of not less than 12 months if:

* * * * *

(ii) * * *

(D) In the case of a limited liability company, the sum of its capital accounts of limited liability company members, and unrealized profit and loss.

* * * * *

(e) No equity capital of the applicant or registrant or a subsidiary's or affiliate's equity capital consolidated pursuant to paragraph (f) of this section, whether in the form of capital contributions by partners (including amounts in the commodities, options and securities trading accounts of partners which are treated as equity capital but excluding amounts in such trading accounts which are not equity capital and excluding balances in limited partners' capital accounts in excess of their stated capital contributions), par or stated value of capital stock, paid-in capital in excess of par or stated value, retained earnings or other capital accounts, may be withdrawn by action of a stockholder or partner or limited liability company member or by redemption or repurchase of shares of stock by any of the consolidated entities or through the payment of dividends or any similar distribution, nor may any unsecured advance or loan be made to a stockholder, partner, sole proprietor, limited liability company member, or employee if, after giving effect thereto and to any other such withdrawals, advances, or loans and any payments of payment obligations (as defined in paragraph (h) of this section) under satisfactory subordination agreements and any payments of liabilities excluded pursuant to paragraph (c)(4)(vi) of this section which are scheduled to occur within six months following such withdrawal, advance or loan:

* * * * *

(g)(1) The Commission may by order restrict, for a period up to twenty business days, any withdrawal by a futures commission merchant of equity capital, or any unsecured advance or loan to a stockholder, partner, limited liability company member, sole proprietor, employee or affiliate, if:

(i) Such withdrawal, advance or loan would cause, when aggregated with all other withdrawals, advances or loans during a 30 calendar day period from the futures commission merchant or a subsidiary or affiliate of the futures commission merchant consolidated pursuant to § 1.17(f) (or 17 CFR 240.15c3–1e), a net reduction in excess adjusted net capital (or, if the futures commission merchant is qualified to use the filing option available under § 1.10(h), excess net capital as defined in the rules of the Securities and Exchange Commission) of 30 percent or more, and

(ii) The Commission, based on the facts and information available, concludes that any such withdrawal, advance or loan may be detrimental to the financial integrity of the futures commission merchant, or may unduly jeopardize its ability to meet customer obligations or other liabilities that may cause a significant impact on the markets.

(2) The futures commission merchant may file with the Secretary of the Commission a written petition to request rescission of the order issued under paragraph (g)(1) of this section. The petition filed by the futures commission merchant must specify the facts and circumstances supporting its request for rescission. The Commission shall respond in writing to deny the futures commission merchant's petition for rescission, or, if the Commission determines that the order issued under paragraph (g)(1) of this section should not remain in effect, the order shall be rescinded.

* * * * *

Issued in Washington, DC, on January 5, 2007 by the Commission.

Eileen Donovan,

Acting Secretary of the Commission.

[FR Doc. E7–173 Filed 1–9–07; 8:45 am]

BILLING CODE 6351–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM06–4–001; Order No. 679–A]

Promoting Transmission Investment Through Pricing Reform

Issued December 22, 2006.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule; order on rehearing.

SUMMARY: In this order on rehearing, the Federal Energy Regulatory Commission (Commission) reaffirms its determinations in part and grants rehearing in part of *Promoting Transmission Investment through Pricing Reform, Order* No. 679. Order No. 679 amended Commission regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

DATES: *Effective Date:* This final rule and order on rehearing will be effective on February 9, 2007.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

Order on Rehearing

I. Introduction

1. On July 20, 2006, the Commission issued a Final Rule in this proceeding.[1] In the Final Rule, the Commission amended its regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities. These incentives are intended to benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. We took this action pursuant to section 1241 of the Energy Policy Act of 2005 (EPAct 2005),[2] which added a new section 219 to the Federal Power Act (FPA). The Final Rule identified ratemaking treatments available under section 219. The Final Rule did not grant incentives to any particular entity, but rather required each applicant to demonstrate that it could meet the requirements of section 219 and the Final Rule.

2. Many entities sought rehearing of the Final Rule.[3] The petitioners representing consumer interests argue that the Final Rule was too permissive in offering rate incentives. We have carefully reviewed these petitions and grant them in part in this order.

3. In doing so, we do not, however, depart from a fundamental commitment to provide incentives to support the development of transmission infrastructure. Section 219 was enacted

[1] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, 71 FR 43294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (Order No. 679 or Final Rule).

[2] Energy Policy Act of 2005, Pub. L. No. 109–58, 119 Stat. 594, 315 and 1283 (2005).

[3] The parties who filed the requests for rehearing and/or clarification are listed in Appendix A.

because of a long decline in transmission investment that is threatening reliability and causing billions of dollars in congestion costs. To reverse this historical trend, section 219 directed the Commission to ''establish, by rule, incentive-based (including performance-based) rate treatments'' that: ''Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and allow recovery of—(A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 and (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.'' [4] The Final Rule fulfilled that command by providing a range of rate treatments that remove impediments to new investment or otherwise attract that investment.

4. This order retains those rate treatments, but modifies the way in which they are applied in three principal respects to address the concerns of petitioners.

5. First, NARUC argues that we erred in rebuttably presuming that certain review processes (*e.g.*, state siting approvals and regional planning processes) satisfy section 219's requirement that a transmission project ensure reliability or reduce congestion. NARUC contends that these review processes do not, in all cases, establish the need for a particular facility. We grant rehearing in part on this issue. The Commission created the rebuttable presumption because we do not wish to duplicate the work of state siting authorities, regional planning processes, or the U.S. Department of Energy (DOE) under EPAct section 1221. However, we agree with NARUC to the extent that, if review processes do not include a determination of whether a project ensures reliability or reduces congestion, no rebuttable presumption should exist for that project. We will therefore require that each applicant explain whether any process being relied upon for a rebuttable presumption includes a determination that the project is necessary to ensure reliability or reduce congestion. Furthermore, we clarify that this rebuttable presumption applies only to whether the project reduces congestion or encourages reliability, not the additional requirements of the Final Rule. As discussed more fully elsewhere in this order, we also grant rehearing with respect to the Final Rule's rebuttable presumption concerning a National Interest Electric Transmission Corridor (NIETC) designation.

6. Second, the Final Rule required that each applicant demonstrate a nexus between the incentive being sought and the investment being made. Several petitioners argue that the nexus test is not sufficiently rigorous to protect consumers. We grant rehearing in part on this issue. The Final Rule stated that the nexus test is to be applied separately to each incentive, rather than to the package of incentives as a whole. We agree that this approach fails to protect consumers where an applicant both seeks incentives that reduce the risk of the project and seeks an enhanced rate of return on equity (ROE) for increased risk. We will therefore grant in part rehearing and require applicants to demonstrate that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project.[5] If some of the incentives in the package reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE.

7. Third, several petitioners argue that the Final Rule erred in its treatment of incentive returns on equity. Specifically, they fear the Commission will routinely grant ROEs at the top end of the zone of reasonableness. Although the Commission has broad discretion to establish returns on equity anywhere within the zone of reasonableness, we must be careful in the manner we exercise this discretion. The Commission clarifies below that we do not intend to grant incentive returns ''routinely'' or that, when granted, they will always be at the ''top'' of the zone of reasonableness. Rather, each applicant will, first, be required to justify a higher ROE under the required nexus test and, second, to justify where in the zone of reasonableness that return should lie. Furthermore, we recognize that some investors may desire up-front certainty regarding ROE before they invest in a particular project. Because our traditional ratemaking practice typically determines ROE in a hearing only after an investment is made and a facility is constructed, it does not provide such up-front certainty. We therefore clarify that we will entertain requests for a specific ROE determination in a petition for declaratory order.

8. In this order, the Commission denies in part and grants in part the requests for rehearing and/or clarification.

II. Background

9. Section 1241 of EPAct 2005 directed the Commission to establish, no later than one year after enactment of section 219, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[6] To that end, the Commission issued a Notice of Proposed Rulemaking (NOPR) [7] on November 18, 2005 seeking comment on the Commission's proposal to comply with section 219. In the NOPR, the Commission stated that the purpose of this rulemaking is to promote greater capital investment in new transmission capacity, recognizing that the need for capital investment in energy infrastructure is a national problem that requires a national solution. Inadequate transmission infrastructure results in transmission congestion that impedes competitive wholesale markets and impairs the reliability of the electric grid.[8]

10. After considering the comments on the NOPR, the Commission issued its Final Rule on transmission investment incentives to address the need for transmission capacity. In the Final Rule, the Commission provided incentives for transmission infrastructure investment that will help ensure the reliability of the bulk power transmission system in the United States and reduce the cost of delivered power to customers by reducing transmission congestion. The Final Rule identified specific incentives that the Commission will allow when justified in the context of individual declaratory orders or section 205 filings

[4] 16 U.S.C.A. 824s(a), (b)(1) (West Supp. 2006).

[5] The Commission will apply a rule of reason with respect to what is sufficient to meet the requirement of ''demonstrable'' risk or challenge. An applicant may provide specific evidence of a risk or challenge or a supported explanation of why it faces a particular risk or challenge.

[6] 16 U.S.C.A. 824s(a) (West Supp. 2006).

[7] *Promoting Transmission Investment Through Pricing Reform*, Notice of Proposed Rulemaking, 70 FR 71409 (Nov. 29, 2005), FERC Stats. & Regs., Proposed Regs. ¶ 32,593 (2005).

[8] *Id.* P 2.

by public utilities under the FPA.[9] The Commission stated that the Final Rule does not grant incentives to any public utility but instead permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219. Further, incentives will be permitted only if the incentive package as a whole results in a just and reasonable rate.[10]

III. Discussion

A. Procedural Matters

11. In response to the Final Rule, a number of parties submitted timely requests for rehearing and/or clarification. On August 22, 2006, the Attorney General of the State of Connecticut (Connecticut AG) filed a request for rehearing out of time, seeking to support and join in all aspects the New England Commissions' request for rehearing. On September 21, 2006, International Transmission Company (International Transmission) filed an answer to SoCal Edison's request for rehearing.

12. Pursuant to Rule 713(b) of the Commission's Rules of Practice and Procedure, 18 CFR 385.713(b) (2006), we will deny the request for rehearing of the Connecticut Attorney General because it was filed more than 30 days after issuance of the Final Rule.[11] Rule 713(d) of the Commission's Rules of Practice and Procedure[12] prohibits an answer to a request for rehearing. Therefore, we deny International Transmission's answer to SoCal Edison's request for rehearing.

B. Statutory Arguments

1. Rehearing Requests

13. APPA/NRECA argue that the Commission misinterpreted section 219 as requiring greater flexibility in ratemaking practices. According to APPA/NRECA, ''incentives'' are not necessary to attract capital because, under existing Supreme Court precedent, ''a public utility's rate of return should also be sufficient to attract investment in new transmission facilities.''[13] APPA/NRECA therefore conclude that section 219 merely ''codified the longstanding Commission and judicial interpretations of FPA section 205's requirement that rates be just and reasonable.''[14]

2. Commission Determination

14. We agree with APPA/NRECA that section 219 did not modify the requirement that rates be just and reasonable under section 205, but disagree that it did no more than restate that longstanding principle. Section 219 makes very clear that the Commission ''*shall* establish, by rule, incentive-based (including performance-based) rate treatments'' and that these rate treatments ''*shall* * * * promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities and allow recovery of—(A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 and (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.''[15] These words do far more than ''codify'' the just and reasonable standard; they command the Commission to use its discretion under section 205 to promote capital investment. Furthermore, Congress in section 219 even highlighted the importance of investment in economically or technologically efficient transmission infrastructure.[16] Section 219 was enacted against the backdrop of a long decline in transmission investment that is imposing substantial costs—in congestion and service interruptions—on consumers. If Congress had deemed our existing practices sufficient to reverse this trend, there would have been little need to enact section 219. Section 219 does not simply ''codify'' our legal authority; it requires us to take affirmative action to promote new investment. Although the resulting rates must be just and reasonable, the Commission has significant discretion under section 205 in making that determination and section 219 provides clear direction that we use that discretion to promote new infrastructure, not simply maintain the *status quo.*

15. While section 219 requires us to do more than maintain the *status quo* for transmission pricing, we recognize that our traditional ratemaking authority also requires us to establish a return on a public utility's assets that is ''reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties''[17] and ''should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.''[18] Thus, a base-level ROE sufficient to promote capital investment in transmission facilities historically has not been considered an ''incentive,'' but a requirement of establishing a just and reasonable rate.[19] In this regard, we

[9] Order No. 679, FERC Stats. & Regs ¶ 31,222 at P1.

[10] *Id.* P. 2. Also, in the Final Rule, the Commission agreed with comments that new transmission technologies will be adopted when they are cost effective. The Commission determined that incentives will be considered for advanced technologies through the same evaluation process as other technologies. The Commission declined to make generic determinations regarding the applicability of incentives to particular technologies. Rather, the Final Rule determined that to the extent that applicants seek additional incentives for advanced technologies, the Commission will consider the propriety of such incentives on a case-by-case basis. *Id.* P 288–93, 298–99. The Final Rule required applicants for incentive rate treatment to provide a technology statement that describes what advanced technologies have been considered and, if those technologies are not to be deployed or have not been deployed, an explanation of why they were not deployed. *Id.* P 302. No party sought rehearing concerning the Final Rule's determinations regarding advanced technologies.

[11] We note, however, that the Connecticut Attorney General supports New England Commissions' request for rehearing, which we address in this order.

[12] 18 CFR 385.713(d) (2006).

[13] APPA/NRECA at 12.

[14] Id. at 12–13.

[15] 16 U.S.C.A. 824s(a), (b)(1)–(4) (West Supp. 2006).

[16] See id. at 824s(a) and (b)(3).

[17] *Bluefield Waterworks & Improvement Co.* v. *Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679, 693 (1923).

[18] *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[19] In contrast to a base-level ROE that reflects the financial and regulatory risks of an investment, an ''incentive'' has been more typically associated with specific basis point additions to a base ROE to satisfy discrete policy objectives. *See, e.g., Western Area Power,* 99 FERC ¶ 61,306, *reh'g denied,* 100 FERC ¶ 61,331 (2002) (*Western*), *aff'd sub nom. Public Utilities Commission of the State of California* v. *FERC,* 367 F.3d 925 (D.C. Cir. 2004); *Michigan Electric Transmission Co., LLC,* 105 FERC ¶ 61,214 (2003) (*METC*); *American Transmission Company, L.L.C.,* 105 FERC ¶ 61,388 (2003) (*American Transmission*); *ITC Holdings Corp.,* 102 FERC ¶ 61,182, *reh'g denied,* 104 FERC ¶ 61,033 (2003) (*ITC Holdings*); *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001)

Continued

recognize that our responsibilities under section 205 and our responsibilities under section 219 overlap in significant ways. We recognize that it may be difficult to meaningfully distinguish between an ROE that appropriately reflects a utility's risk and ability to attract capital and an ''incentive'' ROE to attract new investment. Notwithstanding this difficult distinction, consistent with Congress' direction in section 219, we are obligated to establish ROEs for public utilities that both reflect the financial and regulatory risks attendant to a particular project and that are sufficient to actively promote capital investment. We will do so within the zone of reasonableness, including above the midpoint where appropriate, to accomplish these regulatory responsibilities.[20] This end-result ROE, whether characterized as an incentive pursuant to section 219 or as a base-level ROE consistent with the just and reasonable standard of section 205, will take into consideration financial and regulatory risks attendant to the project and thereby satisfy Congress' direction that the Commission ''provide a return on equity that attracts new investment in transmission facilities * * *.''[21]

C. Nexus Requirement

16. In the Final Rule, the Commission stated that the applicant must demonstrate that: (1) The facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219; (2) there is a nexus between the incentive sought and the investment being made; and (3) the resulting rates are just and reasonable.[22] The Commission stated that an applicant is not required to show that, but for the incentives, the expansion would not occur because Congress did not require such a showing. Nevertheless, the Commission maintained that it will require applicants to show some nexus between the incentives being requested and the investment being made, *i.e.*, to demonstrate that the incentives are rationally related to the investments being proposed.[23]

3. Rehearing Requests

17. Industrial Consumers oppose allowing applicants to request multiple incentives, arguing that the Commission erred by determining that section 219 does not require applicants to demonstrate a relationship between an incentive proposal and transmission investment.[24] According to Industrial Consumers, the just and reasonable requirements of section 219(d) require that incentive rates must be based on a showing that there is a relationship between increased rates and the attraction of new capital.[25] They assert that customers should not be forced to pay for incentives unless those incentives are actually necessary to deliver additional transmission capacity. Therefore, Industrial Consumers claim that contrary to the Commission's conclusion, section 219 does not authorize the Commission to depart from judicial precedent on just and reasonable incentive rates.[26] Further, to the extent that the Commission relies on non-cost factors in determining just and reasonable incentive rates, the Commission must specify the nature of the relevant non-cost factors and offer a reasoned explanation of how the factors justify the resulting rates.[27] Industrial Consumers contend that the reasoned explanation must calibrate the relationship between increased rates and the attraction of new capital, ensure that the increase is in fact needed, and is no more than needed to accomplish the objective.[28]

18. APPA/NRECA also argue that applicants must demonstrate a need for the incentive rate treatments and make a showing sufficient for the Commission to find that a particular incentive rate treatment ''is in fact needed and no more than is needed'' under the FPA and the Administrative Procedure Act.[29] APPA/NRECA consider the nexus requirement to be inadequate because it fails to require applicants to show that a particular rate treatment is actually a lawful incentive under sections 205 and 219 of the FPA.[30] They assert that under the nexus requirement, an applicant could show a sufficient rational relationship merely by claiming that granting the incentive rate treatment will make the investment more profitable and thus more attractive to investors.[31] TDU Systems repeat these points and claim that the nexus requirement will have no effect on the granting or denying of incentive applications unless the Commission provides concrete examples of categories of asserted relationships between proposed incentives and facilities that will not satisfy the nexus requirement. They also do not consider the nexus requirement to be a reasonable substitute for a cost-benefit analysis.[32]

19. Likewise, TAPS argues that the nexus requirement is unduly vague because it fails to clearly require a causal connection between the incentive and consumer benefits. TAPS asserts that the nexus requirement should test whether a requested incentive would reasonably be expected to cause either a net decrease in delivered power costs even after considering incentive-increased transmission costs, or, where the expected net effect on delivered power costs is an increase, reliability gains that make that increase worthwhile.[33] To remedy the alleged deficiencies of the nexus requirement, TAPS proposes that the nexus requirement be revised to provide: ''That the incentive sought is designed to result in those facilities being invested in, completed, and placed into service.''[34] TAPS also recommends that the rule be amended to explicitly retain a reasonable calculation test, so that the Commission can determine which incentives return net consumer benefits and will be able to verify the accuracy of its prediction that granting incentives will spur increased investment.[35]

3. Commission Determination

20. Petitioners raise two related objections to the nexus requirement: (i) That it is too vague and therefore will be too easy to satisfy, and (ii) because it is not sufficiently rigorous, a different standard should be adopted. We address each in turn.

21. The required nexus test requires an applicant to demonstrate that the

(Order No. 2000). Section 219 addresses both situations. In addition to requiring the Commission to establish, by rule, incentive rate treatments to promote transmission investment generally, section 219 also requires the Commission to establish incentive-based rates to encourage transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities. Thus, Congress intended for us to establish an ROE sufficient to reflect financial and regulatory risks and also to consider discrete ROE incentives for, among other things, participation in transmission organizations, projects with particular benefits to reliability or reducing congestion, new technologies and efficiency enhancements.

[20] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 93.

[21] 16 U.S.C.A. 824s(b)(2) (West Supp. 2006).

[22] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 2, 26.

[23] *Id.* P 26, 48.

[24] Industrial Consumers at 3–7.

[25] *Id.* at 4, citing *Farmers Union Cent. Exch.* v. *FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984) (*Farmers Union*).

[26] *Id.* at 5.

[27] *Id.* at 6–7

[28] *Id.*

[29] 5 U.S.C. 556 (2000).

[30] APPA/NRECA at 22.

[31] *Id.* at 23, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91, 117, and 133.

[32] TDU Systems at 19–20.

[33] TAPS at 8–9.

[34] *Id.* at 11.

[35] *Id.* at 16, citing *City of Charlottesville* v. *FERC,* 661 F.2d 945, 955 (D.C. Cir. 1981).

incentives being requested are '' tailored to the risks and challenges faced'' by the project.[36] By this we mean that the incentive(s) sought must be tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project.[37] The required nexus test therefore satisfies the Industrial Consumers request that there be a relationship between the rate treatments sought and the attraction of new capital.[38] It also satisfies TAPS' request that ''the incentive sought is designed to result in'' new facilities being constructed.[39] We disagree with TAPS and APPA/NRECA, however, that the test is designed to be lenient or that it will necessarily be satisfied in every case. As we indicated in the Final Rule, ''[n]ot every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made.'' [40] In evaluating whether the applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project.

22. TDU Systems complain that we did not provide ''concrete examples'' of showings that would either satisfy or fail the nexus test. Although that was not the purpose of the Final Rule—the purpose was to enunciate the criteria to be applied in individual cases—we did provide certain illustrations. For example, we emphasized the need for incentives for new transmission projects that can integrate new generation and load and thereby improve reliability and reduce congestion:

> New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (*e.g.*, proximity to wind currents), not simply on a ''local'' basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be ''obligated'' to build such facilities. Indeed, many of these projects may be too large for a single load serving entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability.[41]

We also emphasized that ''this does not mean that every new transmission investment should receive a higher return than otherwise would be the case. For example, routine investments to meet existing reliability standards may not always * * *, qualify for an incentive-based ROE.'' [42]

23. The Commission reaffirms that the most compelling case for incentives are new projects that present special risks or challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service. We therefore reject the arguments of EEI and Southern Companies that such routine investments should be treated the same, for purposes of applying the required nexus test, as new projects that present special risks or challenges.[43]

24. We also believe that the guidance provided in the Final Rule is sufficient. The purpose of the Final Rule was to establish criteria to be applied in individual cases, not to provide an exhaustive list of situations where incentives will be granted or denied. The decision whether to grant or deny incentives to a particular project is appropriately the subject of an individual rate application (or declaratory order) where the Commission can evaluate whether the applicants have fully supported any incentive rate treatments being sought.

25. We now turn to the alternative tests advocated by petitioners, discussing the ''but for'' test in this section and the ''cost-benefit'' test in the following section. The Final Rule rejected a ''but for'' test as inconsistent with Congressional intent in enacting section 219.[44] We reaffirm that finding here. In doing so, we emphasize that both the required nexus test and the ''but for'' test share one thing in common: Their common objective is to ensure that incentives are not provided in circumstances where they do not materially affect investment decisions. They differ sharply, however, in the means by which they seek to achieve that objective. The ''but for'' test requires an applicant to show that a facility would not be constructed unless the incentive is granted. We reject that test because it erects an evidentiary hurdle that could only, in very rare cases, be satisfied. There are many impediments to investing in new transmission, including siting concerns, financing challenges, rate recovery concerns, etc. It is therefore unreasonable to expect or require an applicant to show that a facility could not be constructed ''but for'' the removal of a *single* impediment—*e.g.*, increased cash flow through 100 percent construction work-in-progress (CWIP) or an enhanced ROE. This test could rarely, if ever, be satisfied, particularly given that incentives are ordinarily sought *before* investment decisions are made and, hence, before any siting impediments are even confronted.

26. The Commission therefore reaffirms its rejection of the ''but for'' test as the appropriate test for applying section 219. It would erect a barrier that is nearly impossible to meet and is thereby fundamentally incompatible with Congressional intent in enacting section 219. In enacting EPAct 2005, Congress plainly understood that there are many impediments to new transmission investment. Congress therefore took a variety of actions to address that problem, including giving the Commission backstop siting authority, requiring that entities have long-term transmission rights to support new investment and, in section 219, providing appropriate rate incentives. We decline to render section 219 essentially an empty letter by requiring the demonstration of a negative—that absent an incentive rate treatment, under no circumstance would a transmission project possibly be built. This would be directly contrary to the intent of Congress to encourage the construction of needed transmission.

27. We will grant rehearing, however, in one respect. The Final Rule states that the nexus test is to be applied separately to each incentive, rather than to the package of incentives as a whole. We agree that this approach fails to protect consumers where an applicant seeks incentives that both reduce the risk of the project and offer an enhanced ROE for increased risk. Even though the applicant no longer has to apply the nexus requirement separately to each incentive, the applicant will be required to demonstrate that the *total* package of incentives is tailored to address the

[36] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26.

[37] We also note that the Commission retains its discretion to provide policy-based incentives. As the courts have said, even prior to our new authority in section 219, the Commission's incentive rate determinations ''involve matters of rate design * * * [and] policy judgments [that go to] the core of [the Commission's] regulatory responsibilities.'' *Maine Public Utilities Commission* v. *FERC,* 454 F.3d 278, 288 (D.C. Cir. 2006). *See also Permian Basin Area Rate Cases,* 390 U.S. 747 (1968) (*Permian*).

[38] Industrial Consumers at 4.

[39] TAPS at 11.

[40] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26.

[41] *Id.* P 25.

[42] *Id.* P 27.

[43] *See infra* P 52.

[44] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 48.

demonstrable risks or challenges faced by the applicant. In presenting a package to the Commission, applicants must provide sufficient explanation and support to allow the Commission to evaluate each element of the package and the interrelationship of all elements of the package. If some of the incentives would reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE. We are revising § 35.35(d) to reflect this clarification.

D. Cost-Benefit Analysis

28. In the Final Rule, the Commission adopted the proposal in the NOPR not to require applicants for incentive-based rate treatments to provide cost-benefit analyses. The Commission noted that courts have recognized that the Commission may consider non-cost factors in its ratemaking decisions.[45] Therefore, the Commission stated that it may consider non-cost factors as well as cost factors and that it will consider the justness and reasonableness of any proposal for incentive rate treatment in individual proceedings.

1. Rehearing Requests

29. TDU Systems and APPA/NRECA contend that the Final Rule's failure to require that incentive rates be justified by a cost-benefit analysis is inconsistent with sections 205 and 219 of the FPA. They assert that the Commission needs the information in the cost-benefit analysis to determine whether a particular incentive rate is just and reasonable, *i.e.* whether its cost is outweighed by the benefits customers will receive.[46] APPA/NRECA also contend that the Commission has no basis for concluding that a particular incentive provides consumers with a net benefit, as required under section 219(a), without a cost-benefit analysis.[47] TDU Systems also point out that the Commission and affected customers must have the information necessary to distinguish between proposed projects that would benefit customers a great deal and proposed projects that would benefit customers minimally if at all.[48] Further, in considering non-cost factors, these parties argue that the Commission cannot make a reasoned decision about the appropriateness of non-cost factors in approving an incentive rate without first knowing the costs and benefits of the incentive rate.[49] They assert that intervenors also need this information to evaluate the impact of the rate proposal on them and to understand how much the applicant is relying on non-cost considerations. Moreover, APPA/NRECA contend, if the applicant is not required to present any evidence that consumers obtain net benefits from an increase in their transmission rates, the Commission cannot strike a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable.[50] Further, TDU Systems and APPA/NRECA state that the plain language of section 219 demonstrates that Congress' intent is to promote only efficient investment, investment that benefits consumers. They assert that Congress' unqualified adoption in section 219(d) of the statutory just and reasonable standard demands a cost-benefit analysis.

30. TDU Systems and APPA/NRECA also argue that elimination of the cost-benefit analysis will be harmful to customers because of the two-stage application procedure.[51] They assert that applicants should be required to provide the Commission and customers with all relevant facts concerning costs and benefits at the petition for declaratory order stage, where the applicant's right to the incentive will be decided, because the Final Rule precludes relitigation of these issues in the later section 205 proceeding.[52] They state that the interested parties must have the information needed to raise specific issues as to whether the likely customer benefits of the project justify the likely costs of the incentives to be awarded. They also argue that without a rigorous cost-benefit analysis at the initial stage, the benefits that formed the Commission's initial approval would be so amorphous that there would be little objective data for the Commission to assess in its periodic progress assessments. Allowing recipients of incentives to fix the term of their incentive-rate awards in the absence of a rigorous initial cost-benefit analysis would serve only to perpetuate the contravention of the statutory just and reasonable standard, according to APPA/NRECA. TDU Systems agree, stating that they can perceive no justification for allowing incentive awardees to define the duration of their own awards in the absence of a rigorous initial cost-benefit analysis.

31. Industrial Consumers argue that the Commission impermissibly departed from Order No. 2000,[53] without a reasoned explanation, by eliminating the cost-benefit analysis. They assert that the Commission wrongly concluded that the cost-benefit analysis is not necessary because customers will be protected by the Commission's review of applications pursuant sections 205, 206, and 219 of the FPA, which require that all rates be just and reasonable and not unduly discriminatory or preferential.[54] They state that in Order No. 2000, the Commission required applicants for innovative transmission rate treatments to demonstrate how the investment in the transmission system benefits consumers and to provide a cost-benefit analysis, including rate impacts. Such a disconnect with Commission precedent reflects an absence of reasoned decision making.[55]

32. Further, Industrial Consumers contend that, to successfully balance the competing interests of providing incentives to encourage transmission investment and its statutory responsibility of protecting customers from excessive rates, the Commission must narrowly tailor incentives that require a close calibration between the increased rates and a corresponding level of benefits. Without such a close calibration between the proposed incentive rates and the anticipated benefit, the Commission risks thwarting the just and reasonable requirements of the FPA. Thus, according to Industrial Consumers, applicants for incentive treatment must be required to demonstrate that incentives will actually yield a positive return in the form of otherwise unachievable reliability improvements and reduced congestion costs.[56]

33. SMUD contends that the nexus requirement is not sufficient to justify eliminating the cost-benefit analysis required under Order No. 2000. It asserts that there is no connection between the lawfulness of non-cost factors and the elimination of the cost-benefit test for incentive rates. SMUD states that, while the Commission recognized the non-cost-based nature of incentive ratemaking in the 1992 Policy

[45] *Id.* P 65, citing *Permian*, 390 U.S. 747, 815 (1968); *Pub. Utils. Comm'n of Cal.* v. *FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) (*CPUC* v. *FERC*); *Maine Pub. Utils. Comm'n.* v. *FERC*, 454 F.3d 278, slip op. at 19 (D.C. Cir. 2006) (*Maine PUC* v. *FERC*).

[46] APPA/NRECA at 26; TDU Systems at 11.

[47] APPA/NRECA at 26–27.

[48] TDU Systems at 12.

[49] *Id.* at 15; APPA/NRECA at 27.

[50] APPA/NRECA at 29, citing *Farmers Union*, 734 F.2d at 1502.

[51] Under the Commission's two-stage application procedure, an applicant can petition for a declaratory order seeking an incentive-based rate treatment for its project. After the Commission issues the declaratory order, the applicant must seek to put the rates into effect through a separate single-issue or comprehensive section 205 filing. *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 76–78.

[52] TDU Systems at 12–14; APPA/NRECA at 29–30.

[53] Order No. 2000, *supra* note 19.

[54] Industrial Consumers at 7–8.

[55] *Id.*

[56] *Id.* at 10.

Statement, the Commission, nonetheless concluded that benefits to consumers must be quantifiable, and SMUD asserts that nothing in section 219 alters the requirement for a cost-benefit test.[57] Further, SMUD contends that the nexus test results in a lower burden of proof for applicants without explaining why a cost-benefit test is no longer necessary. SMUD requests the Commission to clarify that the incentives for new construction to reduce congestion will be capped so that the delivered cost of power to the consumer is lower than what it was before the facilities were constructed, thereby ensuring that consumers will not pay incentive rates for congestion-reducing construction unless the result is a lower cost of delivered power. SMUD also requests clarification that incentives for reliability upgrades will not reward the construction of more transmission capacity than is reasonably necessary to meet new reliability standards, thereby ensuring that incentive payments for reliability improvements will not be awarded for more than what is needed to ensure reliability.

34. TAPS asserts that the Commission's authority to award above-cost incentives has always turned on whether the incentive's cost is outweighed by the benefits customers will receive.[58] TAPS advocates that the Final Rule be amended to explicitly retain a reasonable calculation test that analyzes which incentives spur increased investment, and require the Commission to use this test to replace the cost-benefit requirement.

2. Commission Determination

35. The Commission reaffirms the decision not to adopt a ''cost-benefit'' analysis for four principal reasons.

36. First, the arguments in favor of a cost-benefit analysis start from the premise that our traditional approach to setting transmission rates is fully sufficient to attract new transmission investment in all cases. This premise cannot be squared with section 219. As discussed above, section 219 was enacted to counteract a long decline in transmission investment. Its provisions are mandatory, not permissive, and they proceed from the premise that the Commission must use its full discretion under section 205 to ''promot[e] capital investment.'' It did not, as noted above, simply codify the status quo; it required the Commission to pass a new rule adopting incentive-based rate treatments.

37. These facts readily distinguish the Final Rule from prior instances where the Commission required a cost-benefit analysis.[59] None of those policies was adopted in response to a Congressional directive to use the Commission's discretion under section 205 to address a national problem—the decline in transmission investment that is threatening reliability and imposing billions of dollars in congestion costs on consumers.

38. Second, petitioners fail to recognize that applicants will be required to show that all rates are just and reasonable under section 205. For example, any ROE will remain within the range of reasonable returns. Further, many of the incentives described in the Final Rule only change the timing of cost recovery (e.g., 100 percent CWIP), not the level of cost recovery. Others reduce the risks of investment (e.g., abandoned plant recovery), rather than changing the cost levels. We reiterate that each of the incentives adopted by the Final Rule is fully consistent with our responsibility to ensure that rates are just and reasonable under section 205.

39. Third, those advocating a cost-benefit analysis fail to recognize that the courts have held that the Commission may consider non-cost factors in setting rates.[60] Our authority to consider non-cost factors applies equally in the development of incentive rate-treatments.[61]

40. Finally, although the Commission is rejecting a cost-benefit analysis for the reasons stated above, applicants will nonetheless be required, as discussed above, to demonstrate the required nexus between the incentive being sought and the investment being made. This requirement will ensure that incentives are granted only where the incentives are tailored to address the demonstrable risks or challenges faced by the applicant.

E. Rebuttable Presumptions

41. In the Final Rule, the Commission adopted a set of processes that, if an applicant satisfies them, its project will be afforded a rebuttable presumption that it qualifies for transmission incentives. First, it created a rebuttable presumption that an applicant has met the requirements of section 219 if that project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission.[62] Second, the Commission stated that regional planning processes can provide an efficient and comprehensive forum for evaluating transmission investments' qualifications under section 219 by looking at a variety of options across a large geographic footprint. For example, such a process has the ability to determine whether a given project is needed, whether it is the better solution, and whether it is the most cost-effective option among other alternatives.[63] The Commission also adopted a rebuttable presumption that an applicant has met the requirements of section 219 if a proposed project is located in a NIETC or has received construction approval from an appropriate state commission, agency or state siting authority.[64] The Commission also stated that ''other applicants not meeting these criteria may nonetheless demonstrate that their project is needed to maintain reliability or reduce congestion by presenting [to the Commission] a factual record that would support such a finding.'' [65]

1. Rehearing Requests

42. NARUC and TAPS contend that the Final Rule's rebuttable presumption is not consistent with the statutory requirements of section 219. They state that there was no showing in the Final Rule that assessments in the regional planning processes satisfy the

[57] SMUD at 2, citing *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities: Policy Statement on Incentive Regulation*, 61 FERC ¶ 61,168 at 61,590 (1992) (1992 Policy Statement).

[58] TAPS at 9, citing *CPUC* v. *FERC*, 367 F.3d at 929.

[59] Order No. 2000 required as a condition for any innovative transmission rate treatment that the applicant demonstrate ''a cost-benefit analysis, including rate impacts.'' 18 CFR 35.34(e)(ii) (2006). The Commission notes that in the 6 years since Order No. 2000 was issued, we have not received a single application seeking any of the innovative rate treatments that were provided for in that order. We believe that the requirement of a cost benefit analysis was perceived as an insurmountable hurdle which inhibited the utilities from seeking innovative rate treatments. Accordingly, in developing incentive rate treatments under section 219, the Commission expressly deleted the requirement for a cost-benefit analysis.

[60] See *Permian*, 390 U.S. 747 at 791–2; *CPUC* v. *FERC*, 367 F.3d 925 at 929.

[61] *Maine PUC* v. *FERC*, 454 F.3d at 289 (''particularly in view of the [Commission's] authority to consider non-cost factors in setting rates, the State Commissions' position on calibration demands too much'').

[62] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58.

[63] *Id.* The Commission noted that the value of regional planning was expressly recognized when it proposed to amend the *pro forma* Open Access Transmission Tariff of jurisdictional public utilities to require regional planning to ensure that transmission is planned and constructed on a nondiscriminatory basis to support reliable and economic service to all eligible customers in the region. *See Preventing Undue Discrimination and Preference in Transmission Service*, Notice of Proposed Rulemaking, 71 FR 32,536 (June 6, 2006), FERC Stats & Regs., Preambles ¶ 32,603 at P 36 (2006) (OATT Reform NOPR).

[64] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58.

[65] *Id.* P 57.

requirements of section 219 and there is no basis to assume that the criteria employed in regional planning processes utilize the criteria set out in section 219.[66] Therefore, they argue that it cannot be reasonably presumed that every project that is subject to regional planning will benefit customers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. NARUC further contends that incentives for using regional planning processes are inappropriate in view of the Commission's proposal in the OATT Reform NOPR to require all jurisdictional public utilities to engage in regional planning.[67] Under such a mandatory requirement, all projects will effectively qualify for the rebuttable presumption because all projects will, presumably, be included in approved regional plans.[68]

43. APPA/NRECA, NARUC, TDU Systems, and TAPS argue that the rebuttable presumption for state approvals should be deleted because there is no legal or logical basis to presume that projects falling into this category will ensure reliability or reduce the cost of delivered power.[69] They assert that the criteria applied by the state may not resemble the criteria that the Commission is required to apply under section 219 of the FPA. They argue that state commissions are mainly concerned with protecting retail customers in their respective states and state authorities apply state laws to construction-permit applications. Accordingly, states are not focused on public utility wholesale customers who may be in other states, or ensuring reliability or reducing transmission congestion. Therefore, APPA/NRECA assert that the Commission cannot delegate its responsibilities under section 219 to state authorities that may of necessity have a very different mission.[70]

44. NARUC also claims that projects receiving a designation as projects in NIETC should not receive a rebuttable presumption because such a designation, alone, cannot assure that the statutory prerequisites of section 219 have been satisfied when the criteria for NIETC designation do not mirror those set out for incentives under the statute.[71]

[66] NARUC at 5–6; TAPS at 7–8.

[67] *See* OATT Reform NOPR, FERC Stats & Regs., Preambles ¶ 32,603 at P 36.

[68] NARUC at 6.

[69] *Id.* at 7; TAPS at 6; APPA/NRECA at 37–39; TDU Systems at 25–27.

[70] APPA/NRECA at 38.

[71] NARUC at 7.

45. Additionally, NARUC, APPA/NRECA, and TDU Systems claim that the scope of the rebuttable presumption is ambiguous and needs to be clarified. They state that it is not clear to which part of the three-part showing that the rebuttable presumption applies to.[72] They state that the rebuttable presumption should only apply to the first part (ensure reliability or reduce the cost of delivered power by reducing transmission congestion) of the three-part showing because the only way an applicant can appropriately satisfy the statutory requirements of FPA section 219 is to demonstrate on the record that the project either ensures reliability or reduces the cost of delivered power and that the rates satisfy sections 205 and 206 of the FPA. Therefore, the applicant must still demonstrate with factual evidence that there is a nexus between the incentive sought and the investment being made and that the resulting rates are just and reasonable.[73] APPA/NRECA also request the Commission to clarify that this interpretation applies to both section 205 filings and petitions for declaratory order.[74] TAPS contends that the rebuttable presumptions conflict with the Commission's intended limitations on the receipt of incentives, such as routine investments, which may be included in a regional plan and required to receive state siting approval prior to construction, but may not always qualify for an incentive-based ROE.[75]

2. Commission Determination

46. We will grant rehearing and clarification in part. The Commission created the rebuttable presumption for the purpose of avoiding duplication in determining whether a project maintains reliability or reduces congestion. We do not wish to repeat the work of state siting authorities, regional planning processes, or the DOE in evaluating these issues. However, we agree with NARUC that if such processes do not in fact include such a determination, a rebuttable presumption would not be appropriate. Accordingly, we grant rehearing and are modifying § 35.35 in three ways.

[72] Under section 35.35(d) of the regulatory text, an applicant for incentive rates is required to make a three-part showing that: (1) The facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219; (2) there is a nexus between the incentive sought and the investment being made; and (3) resulting rates are just and reasonable. 18 CFR 35.35(d) (2006).

[73] APPA/NRECA at 35–36; NARUC at 7–8; TDU Systems at 24–25.

[74] APPA/NRECA at 36.

[75] TAPS at 8, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

47. First, we agree with NARUC that the NIETC process will not necessarily determine that every transmission project within a designated corridor will meet the section 219(a) requirements, nor is DOE required to make such a determination. However, we do not believe it is necessary to retain this particular rebuttable presumption in our regulations because any project which is proposed in a NIETC will of necessity have to go through a state or federal siting process. If an applicant's proposed project is within a NIETC, we expect that it will be sited in most instances by the appropriate state siting authority and the applicant will be able to rely on the state siting rebuttable presumption for meeting the requirements of section 219(a). In those cases where projects within a NIETC are sited by this Commission pursuant to our new authority in section 216, an applicant may rely on our findings in our siting process for meeting the requirements of section 219(a).[76] Thus, applicants with projects in a NIETC have an opportunity to rely upon the appropriate siting processes to meet the requirement that a project ensure reliability or reduce the cost of delivered power by reducing transmission congestion, and we need not include the NIETC process as a rebuttable presumption.[77]

48. We are amending our regulations to provide that an applicant that obtains Commission authorization under section 216 to site electric transmission facilities in interstate commerce shall be deemed to satisfy the requirements of section 219(a).[78]

[76] As stated in section 216, the Commission may exercise its new siting authority if inter alia it finds that the construction or modification of the facilities "significantly reduce transmission congestion in interstate commerce and protects or benefits consumers." Since the Commission is required to find that a project reduces transmission congestion before it can authorize the siting of a transmission facility within a NIETC, such facilities necessarily satisfy the requirement of section 219(a) and these regulations.

[77] While DOE is not required to determine whether all projects within a NIETC meet the pre-requisites of section 219, we anticipate that DOE is likely to consider whether transmission projects within these corridors ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Thus, an applicant that does not rely upon a rebuttable presumption for meeting the pre-requisites of section 219 may nonetheless use the findings made by the DOE. Accordingly, the Commission will give due weight to the DOE's determinations concerning the ability of transmission projects within a NIETC to ensure reliability or reduce the cost of delivered power by reducing transmission congestion.

[78] Section 216(b)(4). *See also Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities*, Order No. 689, 71

49. Second, we will modify our regulations to require each applicant seeking to invoke the rebuttable presumption to explain in its filing how the applicable process (regional planning or state approval) in fact considered whether the project ensures reliability or reduce congestion. We continue to believe that, these approval processes will, in all likelihood, examine whether the project maintains reliability or reduces congestion. But in instances where this is not the case the applicant will bear the full burden of demonstrating such facts.

50. Third, we also clarify that the rebuttable presumption applies only to the requirement that an applicant demonstrate, that a project is needed to ensure reliability or to reduce congestion. It does not apply to any other requirement in 18 CFR 35.35, such as the requirement, that the applicant demonstrate the required nexus between the incentive sought and the investment being made [79] and that the resulting rates are just and reasonable in either the petition for declaratory order or section 205 filing. We will modify our regulations accordingly.

F. ROE Sufficient To Attract Investment

51. In the Final Rule, the Commission adopted the NOPR's proposal to allow, when justified, an incentive-based ROE to all public utilities (i.e., traditional public utilities and Transcos) for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing congestion.[80] By including this provision in the Final Rule, the Commission stated that it satisfied the requirement of section 219 to provide an ROE that attracts new investment in transmission facilities (including related transmission technologies). The Commission stated that it will provide ROEs at the upper end of the zone of reasonableness for transmission investments that meet the requirements of section 219. Further, the Commission clarified that it will continue to use the DCF analysis for ROE determinations.[81] The Commission also noted that not every investment that increases reliability or reduces congestion will qualify for an incentive-based ROE. For example, routine investments may continue to be assessed under traditional ROE determinations because there is an obligation to construct them and high assurance of recovery of the related costs.[82]

1. Rehearing Requests

52. EEI and Southern Companies take exception to the statement in the Final Rule that ''routine investments made to comply with existing reliability standards may not always qualify for an incentive-based ROE.'' [83] They argue that the statement discriminates against projects or upgrades that may be proposed to address reliability concerns, and therefore the statement should be deleted.[84] Southern Companies emphasize that the statutory requirement under 219 makes no distinction between routine or non-routine status; therefore, regardless of status, an investment that promotes reliability should be entitled to incentive rate treatment. In that respect, Southern Companies request the Commission to confirm that all reliability-related investments qualify for incentive-based ROEs.[85] Furthermore, Southern Companies request the Commission to clarify that a single incentive-based ROE should apply to all, not just new, transmission investment.[86]

53. TDU Systems contend that the Commission should reconsider its commitment to grant incentive applicants an ROE at the upper end of the zone of reasonableness. Specifically, TDU Systems claim that the Commission may have difficulty handling all the rate filings that seek extremely high ROEs because of the two-stage process. They contend that the Commission is placing too much reliance on its ability to protect consumer interests in the second stage, section 205 review, and recommends that the Commission relieve some of the pressures by giving incentive applicants a more specific message that the incentives have limits.[87] APPA/NRECA also assert that the Commission has not explained why such an increase in allowed ROEs is, or could be, either necessary to attract capital or otherwise just and reasonable and that the rule does not balance investor and consumer interests in setting incentive ROEs.[88] Accordingly, these parties assert that the Commission should permit incentives only if the package as a whole results in a just and reasonable rate. In so doing, they argue, the Commission should disavow any intent to allow ROEs near the top of the zone of reasonableness and ensure that companies in the proxy group with ROEs at the top of the zone of reasonableness do not become the basis for determining the zone, particularly to the extent incentive ROEs become the base case in future DCF analyses.

54. Similarly, TAPS argues that the Commission must be prepared to apply a much stricter scrutiny to the composition of the proxy group that determines the range of the zone of reasonableness to the extent the Commission continues to declare in favor of rates set at the top of a range that has not yet been established.[89] Also, TAPS recommends that the Commission modify its methodology for proxy results by first averaging the two results per proxy company so that there is one, average result per proxy company, as it does in gas cases,[90] thereby providing a more defensible basis for just and reasonable returns. TAPS requests the Commission to clarify that it will ensure that the top of the range does not become a self-

FR 69,440 at P 41 (Dec. 1, 2006) (''The Commission will review the proposed project and determine if it reduces the transmission congestion identified in DOE's study and if it will protect or benefit consumers. It will investigate and determine the impact the proposed facility will have on the existing transmission grid and the reliability of the system'').

[79] We note that the Final Rule's statement regarding routine investment cited by TAPS, applies to the nexus demonstration, and therefore there is no conflict between the rebuttable presumption and that statement.

[80] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91.

[81] This analysis, undertaken in individual rate applications, assesses representative proxy companies and the impact of other factors, including risk, on the zone of reasonableness for ROE. *Id.* P 92.

[82] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

[83] *Id.*

[84] EEI at 11; Southern Companies at 3.

[85] Southern Companies at 4.

[86] 86 Southern Companies argue that section 219(b)(2) should be read to require the Commission to re-examine its ratemaking methods and revise it current ROE policies for all transmission investment, and that the base ROE must be sufficient to attract new investment. It contends that Congress did not state that the Commission shall provide a return on equity *for* new investment in transmission. Instead, section 219(b)(2) states that the Commission shall ''provide a return on equity that attracts new investment in transmission.'' *See Id.* at 5 (emphasis provided by commenter).

[87] TDU Systems at 27–29.

[88] APPA/NRECA at 9, 47.

[89] TAPS explains that many transmission owners will request rates at the high end of the zone of reasonableness and that the main restraint on transmission rates will be the ceiling that is set by the placement of the top of the zone of reasonableness. The zone has been defined by taking a sample group that includes a large number of proxy companies and calculating two data points per proxy. Each pair of points represents the extreme values for each company. The zone of reasonableness is often characterized as reaching up to the higher data point for the most extreme company in the proxy set. Thus, when the top of the range sets the return, it becomes critical to ensure that every company included in the proxy group very closely resembles the utility whose return is being capped, i.e., its capital structure, business risk, financial risk, and associated capital costs. *See* TAPS at 18–22.

[90] *Id.* at 21, citing *High Island Offshore System, L.L.C.,* 110 FERC ¶ 61,043, at P 148 (2005).

escalating spiral with the highest proxy result reflecting an investor expectation that the proxy itself will garner above-cost incentive profits.[91]

55. Southern Companies consider the Commission's continued reliance on DCF analysis in the Final Rule to be contrary to Congressional intent and policy.[92]

Accordingly, Southern Companies request the Commission to clarify that it will allow the use of additional ROE estimation methodologies [93] because these methodologies will better ensure that an entity is ensured a reasonable rate of return. Southern Companies assert that failure to consider the results of more than one methodology, although there are other sound methods, constitutes arbitrary and capricious decision making.[94] Furthermore, Southern Companies consider the Final Rule's refusal to recognize the flaws in the current DCF analysis to be arbitrary and capricious and its finding that the DCF analysis yields just and reasonable results to be in error, particularly in light of the fact that the DCF analysis drives a utility's stock price to its book value while market values exceed book values by approximately 2.47 to 1 as of December 31, 2005 and the constant-growth DCF model often produces divergent and meaningless results.[95]

56. Southern Companies also argue that ROE adders should be provided to all new transmission construction. They assert that section 219 directs the Commission to promote investment of *all* facilities and therefore the Commission's determination in the Final Rule that it will not create specific ROE adders is contrary to EPAct 2005 and requiring applicants to go through a rate case prior to receiving any incentives would unnecessarily impede Congress' stated goal of encouraging new transmission investment.[96]

57. The California Commission claims that the Commission did not engage in reasoned decision making in the Final Rule because it failed to consider risk assessment and did not address its arguments about the relative low risk of transmission investment.[97] It argues that the Commission failed to explain why transmission entities should be eligible for a higher ROE given the low risk associated with transmission investments. The California Commission states that transmission businesses have a low financial risk because they generate a steady revenue stream as a regulated monopoly. Also, among the three functions of an integrated utility's electricity business, *i.e.* generation, distribution, and transmission, the transmission business carries the lowest risk.[98] Further, the California Commission argues that the Commission did not consider the effect the multiple incentives created by the Final Rule will have on lowering the risk, such as 100 percent recovery of CWIP before a transmission project is used and useful. Accordingly, it contends that above-average ROEs for transmission are not needed to effect new transmission facilities.[99]

58. New England Commissions argue that the Commission arbitrarily, capriciously, and without a reasonable factual foundation, determined that ROE incentives encourage investment and make transmission projects attractive.[100] They state that the New England ROE proceeding in *Bangor Hydro-Electric* [101] demonstrated that an enhanced ROE will not change transmission owners' performance in any material respect, but will merely give them an unjust and unreasonable windfall. Accordingly, New England Commissions assert that the Commission's finding that transmission incentives are necessary is not supported by the record in this rulemaking or in the *Bangor Hydro-Electric* proceeding.[102] According to the New England Commissions, it is contrary to the directive in section 219(d) that rates be just and reasonable to dispense with any showing of need before awarding ROE incentives.[103] New England Commissions requests the Commission to clarify that it will judge the justness and reasonableness of ROE adders in New England based on the record in *Bangor Hydro-Electric* proceeding and specify in the rule that only a case-by-case evaluation can determine whether an ROE incentive will produce justifiable benefits.

2. Commission Determination

59. We will grant rehearing and clarification in part on certain issues and deny rehearing on all other issues.

60. We reject the argument of investor-owned utilities that ROE incentives be applied without regard to the nature of the facility being constructed or the risks associated with it. Specifically, the Commission reaffirms that the most compelling case for incentive ROEs are new projects that present special risks or challenges, not routine investments made in the ordinary course. We therefore reject the arguments of EEI and Southern Companies that such routine investments should be treated the same, for purposes of applying the nexus test, as new projects that present special risks or challenges. Although we will consider applications for ROE incentives for all projects, we reiterate that not all projects will be able to meet the nexus requirement. EEI and Southern Companies have provided no compelling reason why a routine investment made in the ordinary course should, as a general matter, receive an incentive ROE.

61. We also reject the argument that incentive ROEs should apply to existing transmission rate base that has already been built. The purpose of section 219 is to attract investment in transmission. Southern Companies have not provided any evidence that higher ROEs for transmission rate base that has already been built are necessary to ensure reliability or to reduce congestion; nor have they shown why such ROEs are necessary to attract new investment in transmission.

62. We also reject the contentions of certain customer groups that incentive ROEs will ''destabilize'' the DCF methodology. First, as indicated above, all ROEs approved pursuant to section 219 will be within the range of reasonableness, as determined consistent with our precedents. Second, any incentive ROEs granted under 219 should have a minimal effect, if any, on the overall range of reasonableness derived from the appropriate proxy group. The DCF methodology uses proxy groups of entire companies, not individual transmission projects. In other words, the ''cash flows'' being measured in the DCF method are the cash flows of entire companies. These cash flows should not be significantly affected by an incentive return for any particular transmission project for one company within the proxy group. Moreover, to the extent there is any

[91] *Id.* at 22.

[92] According to Southern Companies, section 219's requirement that the Commission provide ROEs that are sufficient to attract new transmission investment is evidence of Congress' conclusion that the Commission's current ROE methodology is not producing adequate results. Therefore, the Commission should construe section 219(b)(2) as a mandate from Congress to re-examine its traditional ratemaking policies. Southern Companies at 5–6.

[93] Such methodologies include the risk premium approach, the capital asset pricing model and the comparable earnings approach. *Id.* at 7.

[94] They state that using multiple methodologies recognizes that no single approach can accurately predict an appropriate ROE level so as to satisfy the constitutional and statutory requirements. *Id.* at 8.

[95] *Id.* at 11.

[96] *Id.* at 18.

[97] California Commission at 7–10.

[98] *Id.* at 8.

[99] The California Commission states that even without the high ROE incentive, California IOUs have planned and constructed numerous transmission facilities in the last 10 years. *Id.* at 9.

[100] New England Commissions at 5.

[101] *Bangor Hydro-Electric Co.*, 106 FERC ¶ 61,280 (2004).

[102] New England Commissions at 6–10.

[103] *Id.* at 12.

small effect on the overall range of reasonableness, it will appropriately reflect the substantial risks associated with constructing new transmission, as discussed above.[104]

63. We also reject requests to cease our utilization of the DCF method. Inasmuch as the DCF method yields just and reasonable rates, as the Commission has recognized in numerous proceedings, we see no basis to require other methods for the evaluation of incentive applications. As we stated in the Final Rule, the Commission will consider on a case-by-case basis whether the application of the traditional DCF analysis should be modified.[105]

64. We also do not consider the process for approving incentive ROEs, i.e., setting a zone of reasonableness and a DCF analysis requirement, to be an unnecessary impediment to encouraging transmission investment. Generic adders, as recommended by Southern Companies, would still require the Commission to make a determination that the proposed ROEs are just and reasonable, and its findings would have to be based on reasoned decision-making. Therefore, the Commission necessarily would be required to establish a zone of reasonableness and a justification for the approved ROEs.

65. Responding to the California Commission, the Final Rule explained the basis for its decision to provide an incentive ROE, based on the need to attract investment in the context of long-term industry underinvestment and the need to re-evaluate the balance of investor and ratepayer interests, and therefore has provided the reasons for its decisions. The Commission is not, in this rule, setting the incentive ROE, but rather leaves that determination to future proceedings that will authorize a unique ROE appropriate to the facts and circumstances of each applicant. It is in those proceedings that the California Commission can raise its concerns regarding comparative returns within the energy industry and the specific characteristics of California utilities. However, we agree with the California Commission that utilities should consider the effect that certain incentives (*e.g.* CWIP in rate base, recovery of abandoned plant) may have on risk and that return on equity in the upper end of the zone of reasonableness may not be appropriate when combined with incentive rate treatments that lower overall risk.

66. We do not address the issues raised by New England Commission with respect to the *Bangor Hydro-Electric* proceeding because they have been addressed in a recent Commission order and are now pending on rehearing.[106]

67. We will, however, grant clarification in part. Several petitioners express the fear that the Commission will routinely grant ROEs at the top end of the zone of reasonableness. Although the Commission has broad discretion to establish returns on equity anywhere within the zone of reasonableness, we must be careful in the manner in which we exercise this discretion. The Commission clarifies that we do not intend to grant incentive returns ''routinely'' or that, when granted, they will always be at the ''top'' of the zone of reasonableness. Rather, each applicant will, first, be required to justify a higher ROE under the revised nexus test and, second, to justify where in the zone of reasonableness that return should lie. In some instances, where the risks or challenges faced by a new investment are substantial, we may grant an ROE at the top end of the zone of reasonableness. However, we have no expectation of doing so in all cases or even routinely.

68. We also provide clarification on the timing of an ROE determination. In most instances, an ROE determination occurs in a hearing that considers the justness and reasonableness of the costs of the investment for purposes of setting rates under section 205. In that hearing, the overall range of reasonableness would be established, as well as a determination of where within that range the ROE should be set. If the Commission granted a request for an incentive ROE at the upper end of that range in a petition for declaratory order, the hearing would establish where in the upper end the ROE would fall—whether at the top end or at a different point in the upper end of the range. The Commission would then review any determination by an administrative law judge on that issue.

69. We recognize, however, that our hearing procedures for determining ROE can create uncertainty for investors. Under traditional ratemaking processes, the rates for a particular project, including the ROE for that project, are determined only *after* an investment decision is made and the facility is constructed. This may provide a disincentive to new investments that are sensitive to our ROE determinations. Although our processes are designed to provide a just and reasonable return, we recognize that there can be significant uncertainty as to the ultimate return because of the uncertainties associated with administrative determinations (*e.g.*, selection of the proxy group, changes in growth rates, etc.) This can itself constitute a substantial disincentive to new investment.

70. Recognizing this, we will clarify the approach adopted in the Final Rule. We will continue to allow applicants to request, in a petition for declaratory order, an ROE that is at the upper end of the zone of reasonableness and, in such instances, the ultimate ROE will be determined in the hearing process. However, if an applicant desires up-front certainty of the ROE it will receive, we clarify that we also will consider requests for declaratory orders that set the ROE for a particular project, and that include the appropriate support for the ROE, including, for example, a DCF analysis. An applicant seeking to use this process will have to meet the required nexus requirement, such as by showing that an up-front ROE determination is important for its investment decision. An applicant seeking such an up-front ROE determination also may request an ROE at the upper end of the zone of reasonableness; however, the fact that an up-front ROE determination is itself an incentive that tends to reduce risk will be taken into account in considering any such request.

G. Incentives Available to Transcos

71. In the Final Rule, the Commission approved incentive-based rate treatments applicable to Transcos to encourage Transco formation and attract investment.[107] Specifically, the Commission approved an ROE that encourages Transco formation and is sufficient to attract investment and an adjustment to book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal

[104] The Commission retains the discretion to adjust ROEs if we find that the results of a DCF analysis do not accurately reflect the risk of the applicant and its ability to attract capital.

[105] We agree with TAPS that averaging each company's low and high DCF return would result in a single average DCF result for each electric company, making it like the single DCF return for gas and oil pipelines, from which a median return on equity for the group can be calculated. While this is an acceptable method, we will not require use of that method in the Commission's DCF analysis because that issue is beyond the scope of this proceeding and is more appropriately addressed in the individual application proceedings.

[106] *Bangor Hydro-Electric Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006).

[107] Section 35.35(b)(1) defines Transcos as stand-alone transmission companies approved by the Commission that sell transmission services at wholesale and/or on an unbundled retail basis, regardless of whether they are affiliated with another public utility.

capital gains tax liabilities.[108] The Commission noted that its decision to approve such incentives for Transcos is based on the ''proven and encouraging track record of Transco investment'' in transmission facilities.[109]

1. Rehearing Requests

72. EEI argues that applicants seeking transmission incentives should be treated equally, without regard to their form of business. It argues that the incentives applicable to stand-alone transmission companies should be expanded to apply to all transmitting utilities.[110] EEI also urges the Commission to recognize that all forms of transmission business models can effectively provide transmission facilities and to reiterate that it will evaluate each applicant's proposed incentives, in particular the upper range of reasonable ROEs, without regard to the applicant's form of business and without bias as between forms of business.[111]

73. Southern Companies contend that additional incentives for Transcos are not justified on grounds that the Transcos have a good record of transmission investment.[112] They state that vertically-integrated utilities like Southern Companies have consistently invested significantly in transmission maintenance and expansion. Southern Companies also claim that special ROE incentives solely for Transcos would be discriminatory by favoring one corporate structure over another to the extent both business structures have similar transmission investment records [113] and the requirements of section 219 to promote investment regardless of the ownership of the facilities.

74. APPA/NRECA assert that because the Commission's definition of Transcos includes affiliated Transcos under the control of one or more parent public utilities, granting incentive rate treatment greater than that afforded to public utilities would constitute a financial windfall.[114] They argue that such affiliated Transcos should not be eligible for special incentive rate treatment because such a payment would neither induce new construction nor provide any new benefit to the customer paying the incentive rate.[115]

75. Furthermore, TDU Systems oppose passive ownership interests in Transcos and contend that, if authorized, passive ownership interests should only be authorized upon a showing that the option of investment in the Transco is open to all load-serving entities (LSEs) in the region up to their load ratio shares.[116] They also argue that the Commission must rigorously scrutinize and monitor relationships among the passive owners to deter the potential for abuse. TDU Systems also contend that the Commission should clarify that Transcos may only receive incentive rates if there are no interests within the Transco competing with transmission for capital. They recommend that the Commission condition the granting of incentives by imposing limits on business investments in other industries to avoid the dilution of capital funding from competing sources within the company.[117] They also claim that incentives for new investment in transmission infrastructure should not be necessary because, as the Commission noted in the Final Rule, such incentives are inherent in the corporate business model to encourage investment.[118] Therefore, encouraging additional incentives provides no incremental benefit to consumers.[119]

2. Commission Determination

76. We affirm the finding in the Final Rule that the Commission will not limit an applicant's ability to seek incentive-based rate treatments based on corporate structure or ownership.[120] The Commission will evaluate these applications to determine if incentive treatment is justified based on their demonstrations that the projects meet the requirements of section 219 and this rule. Certain types of incentives, such as the ADIT incentive may be more appropriate where transmission is being spun off or otherwise transferred to a new corporate entity, such as a Transco. But we see no basis for the claim that the Transco incentives are unduly discriminatory or contrary to the goals of section 219.

77. The Final Rule described at great length the very significant transmission investment that has been undertaken by Transcos, to date.[121] There is no reason to repeat those examples again here, but we disagree with comments that suggest that Transcos do not have a good record of transmission investment. Furthermore, their singular focus on transmission investment by transmission-only companies, the elimination of competition for capital between generation and transmission investments, and the access to capital markets have all been cited in support of the value of the Transco business model for getting new transmission built. For all of these reasons, the Commission adopted incentive-based rate treatments applicable to Transcos that would both encourage Transco formation and attract investment.

78. As we stated in the Final Rule, the Commission will consider concerns regarding affiliated Transcos in specific applications for incentive treatment.[122] We believe the Final Rule fulfills the requirements of section 219 by determining eligibility for Transco status and incentive-based rate treatment based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment in individual case proceedings. Therefore, we do not consider this proceeding to be the appropriate forum for adopting preconditions related to other issues, such as affiliation or passive ownership. Inasmuch as Transcos are subject to the Commission's market behavior rules, their activities will be monitored for any potential market abuse. Therefore, we affirm the availability of ROE incentives to Transcos. As stated in the Final Rule, we expect that the incentive ROE will be used for additional capital spending, and thereby provide consumer benefits, as demonstrated by the negative cash flow profiles of Transcos and their future capital spending plans.

[108] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 222–224. The incentive ROE does not preclude a Transco from applying for other incentives, including hypothetical capital structure, allowance for deferred income taxes (ADIT), acquisition premiums, formula rates or deferred cost recovery. *Id.* P 221.

[109] *See id.* P 221–23.

[110] EEI at 5, 7–9.

[111] *Id.* at 5. EEI claims that section 219(b) provides that the rule shall promote transmission investment ''regardless of the ownership of facilities'' and the Commission noted in the Final Rule that it will not limit incentives based on corporate structure or ownership. *Id.* at 7, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 4, 225.

[112] Southern Companies at 16–17.

[113] *Id.* at 17, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 225.

[114] APPA/NRECA at 31, 34–35. In the Final Rule, the Commission stated that the definition of Transco does not exclude affiliated Transcos with active ownership by market participants, or stand-alone transmission companies that own transmission and distribution facilities. The Commission said that it would consider the eligibility of such arrangements based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment and lead to increased transmission investment similar to Transcos the Commission already approved. *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 202.

[115] APPA/NRECA at 31.

[116] TDU Systems at 39.

[117] *Id.* at 40.

[118] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 204.

[119] TDU Systems at 41.

[120] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 4.

[121] *Id.* P 222–23.

[122] *See id.* P 202.

H. Transmission Organization Incentive

79. In the Final Rule, the Commission stated that it will authorize, when justified, an incentive-based rate treatment for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization.[123] Applicants for the incentive-based rate treatment must make a filing with the Commission under section 205 of the FPA. For purposes of section 35.35(e), an incentive-based rate treatment means an ROE that is higher than the ROE the Commission might otherwise allow if the public utility were not a member of a Commission-approved Transmission Organization. The Commission stated that it will not create a generic adder for such membership, but instead will consider appropriate ROE incentives on a case-by-case basis. The Commission also stated that transmitting utilities or electric utilities that join a Transmission Organization would be eligible to apply to recover prudently-incurred costs associated with joining the Transmission Organization, either through rates charged by transmitting utilities or electric utilities or through transmission rates charged by the Transmission Organization that provides services to such utilities.[124] Furthermore, the Commission stated that based on its interpretation of section 219, eligibility for this incentive flows to an entity that ''joins'' a Transmission Organization and is not tied to when the entity joined. Therefore, the Commission clarified that entities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive.[125] However, as the Commission noted, any public utility receiving an incentive ROE for joining a Transmission Organization but withdraws from such organization is no longer eligible for the ROE incentive.

1. Rehearing Requests

80. Petitioners contend that public utilities should not be eligible for the Transmission Organization incentive if the public utilities are already members because the payment would neither induce new construction nor provide any new benefit to the customer paying the incentive rate.[126] They argue that the Final Rule's determination that incentives may go to entities that are already members of a Transmission Organization is contrary to court and Commission precedent interpreting incentive rates as forward-looking inducements, not a reward for past behavior.[127] The California Commission claims that the Final Rule's interpretation of section 219 exceeds the Commission's authority by creating an incentive that is broader than specified in the FPA.[128] Furthermore, TDU Systems assert that many public utilities have already joined ISO or RTOs without ROE incentives and have benefited from such membership. Those public utilities that have not joined have chosen not to do so because their business interests would not be advanced by a reduction in transmission barriers and constraints. Therefore, they argue that ''recalcitrant utilities'' should not be awarded windfall profits for holding out on participating in Transmission Organizations because such action would only amount to rewarding the exercise of market power.[129]

81. Furthermore, the California Commission states that an incentive for utilities that have already joined a Transmission Organization and are planning to build transmission facilities provides no balancing of the consumer interests and represents an unjust windfall.[130] By continuing its membership in an ISO/RTO, a transmission company will not incur any additional risks and will still remain a monopoly. The California Commission and TDU Systems argue that the Commission did not provide any evidence that current RTO/ISO members may leave a Transmission Organization without the incentive of higher ROEs and therefore such a conclusion constitutes unreasonable, unlawful decision making.[131] APPA/NRECA assert that if a member leaves the Transmission Organization, the Commission can simply deny that utility a rate incentive.[132] Further, SMUD notes that there is no assurance that members will be permitted to leave since such a decision is subject to Commission review, and expresses concern that extending incentives to existing members of a Transmission Organization for not leaving may discourage parties legitimately dissatisfied with the Transmission Organization's performance and thereby make these organizations less accountable.[133] Finally, APPA/NRECA argue that the Commission's statement that it would be unduly discriminatory not to award all members of a Transmission Organization an incentive ROE has no basis because nothing in the FPA forbids different rates if these arrangements are necessary to carry out the provisions of the FPA and to serve the regulatory purposes contemplated by Congress.[134]

82. TDU Systems request clarification that the Commission will not consider single company entities as Transmission Organizations. They state that to ensure new transmission investment serves regional markets, a ''collaborative [and] open regional planning process'' is necessary. Therefore, TDU Systems claim that only entities that provide for, or participate in, regional planning that spans a number of public utility transmission systems should be eligible for incentives.[135]

83. TDU Systems recommend a reduction, i.e. negative 50 basis point penalty, in the authorized ROE for public utilities that withdraw from Transmission Organizations within the first five to ten years of participation to recognize the costs paid by consumers in anticipation of long-term savings. TDU Systems also argue that the incentive should not be allowed for public utilities ordered to join Transmission Organizations by statute, merger conditions or other regulatory requirements because there is no nexus between the incentive rates and demonstrated consumer benefits.[136] Finally, SMUD argues that the Final Rule offered no explanation for providing an incentive for utilities that are required to join Transmission Organizations as a merger condition.[137]

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[123] *Id.* P 326. Transmission Organization is defined as ''a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.'' *Id.* P 328.

[124] *Id.* P 329.

[125] *Id.* P 331.

[126] TDU Systems at 43; APPA/NRECA at 31–32, citing *Southern California Edison Company,* 114 FERC ¶ 61,018, at P 16 (2005) (''The rationale for this incentive is to encourage transmission owners to turn over the operational control of their transmission facilities to a regional transmission organization; therefore, it does not apply to transmission owners who have already done so, as they need no inducement to take such action'') (Southern California Edison).

[127] E.g., APPA/NRECA at 32; SMUD at 3–7; TDU Systems at 43. The California Commission argues that the courts have not permitted ROE adders for past conduct. California Commission at 18–19, citing *Maine PUC* v. *FERC,* 454 F.3d 278 (2006) and *Allegheny Power Systems Operating Co.,* 111 FERC ¶ 61,308 (2005).

[128] California Commission at 14–15.

[129] TDU Systems at 42.

[130] California Commission at 16.

[131] *Id.* P 17–18; TDU Systems at 43.

[132] APPA/NRECA assert that the Commission rejected such a remedy without a reasoned explanation in the Final Rule. APPA/NRECA at 32.

[133] SMUD at 3–7.

[134] APPA/NRECA at 33.

[135] TDU Systems at 41–42.

[136] *Id.* at 42–43.

[137] SMUD at 7.

84. MISO TOs state that the Final Rule was unclear on the mechanics of requesting incentives by RTO members and request clarification that transmission owners may seek this incentive without opening up a Commission-accepted ROE or additional rates or formulas.[138] Specifically, they state that the Commission did not clarify that such a single-issue filing will not open up the already Commission-accepted ROE.

85. Finally, APPA/NRECA argues that the Final Rule does not comply with section 219(c) to provide incentives to each transmitting utility or electric utility that joins a Transmission Organization because it disregards incentives to non-jurisdictional utilities.[139] The Commission reasoning that it does not have jurisdiction to provide incentives for non-public utilities joining Transmission Organizations is unjustified when it has asserted jurisdiction in other proceedings.[140] APPA/NRECA recommend the Commission to consider incentives for non-public utilities such as assurances that these entities will fully recover all their costs of joining and participating in the Transmission Organization.

2. Commission Determination

86. We affirm the finding in the Final Rule that the incentive applies to all utilities joining transmission organizations, irrespective of the date they join, based on a reading of section 219 in its entirety. Section 219 specifically provides that ''the Commission shall * * * provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization.'' The stated purpose of section 219 is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power. We consider an inducement for utilities to join, and remain in, Transmission Organizations to be entirely consistent with those purposes. The consumer benefits, including reliability and cost benefits, provided by Transmission Organizations are well documented,[141] and the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of Transmission Organizations and is effective for the entire duration of a utility's membership in the Transmission Organization. To limit the incentive to only utilities yet to join Transmission Organizations offers no inducement to stay in these organizations for members with the option to withdraw, and hence risks reducing Transmission Organization membership and its attendant benefits to consumers. Because the incentive is applicable to utilities that join Transmission Organizations and is consistent with the requirements of section 219 of the FPA, the incentive complies with EPAct 2005 and the FPA.[142]

87. We consider the claim of APPA/NRECA that the incentive is inappropriate because it does not induce construction to be misplaced. Section 219(c), applicable to the Transmission Organization incentive, is separate from the construction incentives in subsection (b), and therefore was not intended to directly encourage construction.[143] However, we note that regional transmission organizations provide a platform for regional planning and cost allocation associated with transmission expansion and planning [144] and therefore can help support the identification and construction of transmission needed to ensure reliability and to reduce congestion.

88. We will not specify a particular method for establishing the appropriate ROE for entities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization in this generic proceeding. For example, the mechanics of setting an incentive ROE is an issue best addressed in a proceeding evaluating the Transmission Organization incentive for transmission owners that belong to the particular Transmission Organization. We recognize that the issue was remanded to the Commission with respect to Midwest ISO.[145] In the order on remand, the Commission observed that Midwest ISO or the MISO TOs can make a filing under section 205 to include an incentive adder.[146]

89. We affirm the Final Rule finding that this incentive applies to public utilities, as required by section 219, and therefore does not apply to non-public utilities and that non-public utilities may be permitted incentive-based rate treatments under section 211(a) of the FPA.

90. We will not make determinations on acceptable Transmission Organization structures and affiliations in this proceeding. The Commission will consider applications to form Transmission Organizations, based on the requirements of § 35.35(b), and make its determinations on the facts and circumstances of each filing.

I. Hypothetical Capital Structure

91. In the Final Rule, the Commission found that hypothetical capital structures can be an effective tool available to public utilities to foster transmission investment in appropriate circumstances. The Commission stated that it has allowed the use of hypothetical structures to improve access to capital markets for transmission investment and for specific projects when shown to be necessary for

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[138] MISO TOs at 2–3.

[139] APPA/NRECA at 53–54.

[140] *Id.* P 54, citing *City of Vernon, California and CAISO,* Opinion No. 479, 111 FERC ¶ 61,092, *reh'g granted in part and denied in part,* 112 FERC ¶ 61,207 (2005), *reh'g denied,* 115 FERC ¶ 61,297 (2006).

[141] In Order No. 2000, in which the Commission's goal was to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service, the Commission stated that:

These benefits [of RTOs] will include: Increased efficiency through regional transmission pricing and the elimination of rate pancaking; improved congestion management; more accurate estimates of ATC; more effective management of parallel path flows; more efficient planning for transmission and generation investments; increased coordination among state regulatory agencies; reduced transaction costs; facilitation of the success of state retail access programs; facilitation of the development of environmentally preferred generation in states with retail access programs; improved grid reliability; and fewer opportunities for discriminatory transmission practices. All of these improvements to the efficiencies in the transmission grid will help improve power market performance, which will ultimately result in lower prices to the Nation's electricity consumers.

Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,024.

[142] In light of our determination here, we reverse the policy adopted in our decision in *Southern California Edison.* Our decision in *Southern California Edison* failed to recognize that incentives are equally important in inducing utilities to join and remain in Transmission Organizations. *Southern California Edison Co.,* 114 FERC ¶ 61,018, at P 16 (2005).

[143] We note that a more accurate interpretation of section 219(c) must recognize that an important component of section 219(c) is ensuring cost recovery, and therefore this section differs from the rest of section 219 that only address incentive-based rate treatments. We note that the Midwest ISO tariff provisions governing pass-through of transmission costs are consistent with this section, and this section would provide the basis for approval of pass-through of costs in other ISOs.

[144] *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,218 (2006); *Midwest Independent Transmission System Operator, Inc.,* 114 FERC ¶ 61,106 (2006), *order denying reh'g,* 117 FERC ¶ 61,241, (2006); *Midwest Independent Transmission System Operator, Inc., et al.,* 113 FERC ¶ 61,194 (2005); *Midwest Independent Transmission System Operator, Inc.,* 109 FERC ¶ 61,168, *order granting clarification,* 109 FERC ¶ 61,243 (2004), *reh'g pending.*

[145] *Midwest Independent Transmission System Operator, Inc.,* 100 FERC ¶ 61,292 (2002), *order on reh'g,* 102 FERC ¶ 61,143 (2003), *order on remand,* 106 FERC ¶ 61,302 (2004), *aff'd in part and reversed in part,* 397 F.3d 1004 (D.C. Cir. 2005).

[146] *Midwest Independent Transmission System Operator, Inc.,* 111 FERC ¶ 61,355, at P 5 (2005).

project financing.[147] To encourage the development of new transmission investment, the Commission noted that it will evaluate each proposal on a case-by-case basis and will not prescribe specific criteria or set target debt/equity ratios for evaluating hypothetical capital structures. As with other incentives, the applicant is required to demonstrate the required nexus between its proposed incentive and the facts of its particular case.[148]

1. Rehearing Requests

92. The California Commission considers the hypothetical capital structure incentive-based rate treatment unnecessary for regulated utilities. According to the California Commission, when a company increases its actual debt ratio to a level higher than its optimal capital structure, the company will expose itself to financial risks at the expense of ratepayers, or will unnecessarily increase ratepayer costs. The California Commission also faults the Commission for not mandating the degree of rigorous scrutiny necessary for all cases before they are approved.[149] TDU Systems urge the Commission to adhere to *Allegheny Power* precedent that rejected hypothetical capital structures unless the utility's actual capital structure was so far out of line with the market-driven capital structures of representative proxy companies so as to be anomalous.[150]

2. Commission Determination

93. We repeat our finding in the Final Rule that hypothetical capital structures can be an appropriate ratemaking tool for fostering new transmission in certain relatively narrow circumstances. Historically, those circumstances have been somewhat unique, such as consortiums that require a special capital structure or projects that need project financing. As with other incentive ratemaking treatments, the Commission will require any applicant to demonstrate the required nexus between the need for a hypothetical capital structure and the proposed investment project. We would not normally expect traditional regulated utilities to propose incentives based on hypothetical capital structures (as was suggested by the California Commission) and we note that the Commission and state commissions have the ability to prevent any regulated company from increasing its debt ratio to a level that unnecessarily exposes wholesale or retail customers to unnecessary risk.

J. Single-Issue Ratemaking

94. The Commission concluded in the Final Rule that single-issue ratemaking can provide a significant incentive for new investment in transmission infrastructure because it can provide assurance that the decision to construct new infrastructure is evaluated on the basis of the risks and returns of that decision, rather than the additional uncertainty associated with re-opening the applicant's entire base rates to review and litigation.[151] The Commission stated that single-issue ratemaking applicants are only required to address cost and rate issues associated with the investment in the section 205 proceeding to approve rates. The applicant, however, is still required to fully develop and support any transmission rate design to recover the costs of a particular transmission system facility or upgrade, including cost allocation and rate design.[152] Further, the Commission noted that each application will be evaluated by balancing the need for new infrastructure, and the importance of permitting single-issue ratemaking in support of that infrastructure, with the concerns over whether a specific mechanism is required to re-open existing rates or whether the traditional complaint processes are sufficient for that purpose.[153]

1. Rehearing Requests

95. Petitioners claim that single-issue ratemaking, as described in the Final Rule fails to balance shareholders' and consumers' interests and permits transmission owners to earn an unjust and unreasonable return on their overall transmission assets. They also assert that the Commission ignored its long-standing policy of rejecting single-issue ratemaking based on precedent that shows that single-issue ratemaking can lead to transmission providers earning super-normal returns while using single-issue rate filings to shield that fact from Commission scrutiny.[154] They argue that the Final Rule allows public utilities to increase their transmission rates on a piecemeal basis without providing procedures, short of section 206 complaints, to ensure that the public utility's steadily increasing rates do not become unlawful. They also contend that the Commission failed to consider reasonable alternatives such as a mandatory full transmission rate case every three years or allowing utilities to use formula rates that ensure a balance between risks borne by shareholders and ratepayers.[155]

96. Xcel states that the Final Rule anticipates the possibility of placing the applicant at risk for being ordered to file a section 205 rate case for its existing investments and contend that this potential risk will have the practical effect of discouraging limited section 205 incentive proposals. Accordingly, Xcel recommends that the Final Rule be modified so that it can achieve its stated purpose of providing assurance that the decision to construct new infrastructure is evaluated on the basis of the risks and returns of that decision, rather than the additional uncertainty associated with re-opening the applicant's entire base rates to review and litigation.[156] According to Xcel, to the extent the Commission believes the new single-issue rate must be harmonized with existing rates, the burden of proof should remain on the Commission, or the utility's customers, to show the existing filed rates are unjust and unreasonable and not shift the burden to the public utility.[157]

2. Commission Determination

97. The Final Rule recognized that requiring transmission owners to open up their existing rates for review and litigation anytime they sought recovery of costs associated with a new transmission project could discourage new investment. Accordingly, the Final Rule permits an applicant to propose transmission rates associated with a particular project without proposing any changes to its existing transmission rates under section 205. We disagree with TDU Systems and APPA/NRECA that single-issue ratemaking will permit transmission owners to earn an unjust and unreasonable return on their overall

[147] The Commission noted that *American Transmission* and *Trans-Elect* are examples of the use of hypothetical capital structure to foster the development of transmission investment. Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 131.

[148] *Id.* P 133.

[149] California Commission at 11–14.

[150] TDU Systems at 35–36, citing *Allegheny Power Co.* 103 FERC ¶ 63,001, at P 28 (2003), *aff'd,* 106 FERC ¶ 61,241, at P 27 (2004) (*Allegheny Power*).

[151] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 191.

[152] *Id.* P 192.

[153] *Id.*

[154] APPA/NRECA argue that, if a public utility has experienced load growth but has not invested in new transmission facilities, the public utility will have a strong disincentive not to file a section 205 rate case, because it will be earning a high rate of return on its highly depreciated rate base. They further assert that it has been their members' general experience that when public utility transmission providers believe they are undercollecting their transmission revenue requirements, they are quick to address the situation through a section 205 filing. APPA/NRECA at 41.

[155] *Id.* at 40–43; TDU Systems at 21–23.

[156] 156 Xcel at 4–5.

[157] *Id.* at 5.

transmission investment and we specifically committed that the Commission would consider the need to combine or reconcile any project-specific transmission rate proposal with any existing transmission rate, where necessary.

98. Indeed, the Final Rule specifies that the Commission may require the applicant to file a full rate case for existing transmission rates when evaluating a single-issue rate application, and therefore provides a procedure for additional rate review. However, we agree with Xcel that further clarification is necessary.[158] As indicated in the Final Rule, applicants for single-issue ratemaking are only required to address cost and rate issues associated with the new investment and therefore are not obligated to justify the reasonableness of unchanged rates.[159] As *PSC of N.Y.* and *Winnfield* make clear, if intervenors or the Commission seek to challenge the applications beyond the limited issues raised in their applications, the intervenors or the Commission bear the burden of proof under section 206 in establishing that the existing, unchanged components of the rate are unjust and unreasonable. We further clarify that Commission review of the single-rate application will not be delayed in the event a separate section 206 investigation is initiated, thereby ensuring that new investments are not impeded because of existing-system rate issues.[160]

99. Based on the precedent cited above, we disagree with the conclusion that acceptance of single-issue rate filings would represent a dramatic shift in the historic balance between interests, and we therefore see no need to require additional consumer protections such as mandatory rate cases.

K. Public Power

100. In the Final Rule, the Commission noted that ratemaking incentives are generally not directly available to non-jurisdictional entities, i.e. public power entities, because they do not file their rates with the Commission.[161] However, the Commission recognized that public power participation can play an important role in the expansion of the transmission system and stated that public power participation in new transmission projects are encouraged. The Commission stated that the Commission will review appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project.[162]

1. Rehearing Requests

101. TAPS requests the Commission to clarify that any approved incentive will be equally available to all owners of facilities that are found to merit incentives, regardless of the entity's form or business model and that the Commission will look with disfavor on incentive rate treatment applications by vertically-integrated utilities that exclude other utilities from co-owning a facility located in their common footprint.[163] TAPS contends that it is unduly discriminatory to allow large utilities to veto transmission incentives by refusing to participate in inclusive ownership arrangements. TDU Systems request the Commission to clarify that the option to participate in planning, financing and construction of new investment belongs to the public power system and that public utilities should not be allowed to use the availability of this option to avoid their obligation to construct needed network upgrades. TDU Systems urge the Commission to reconsider its determination that the Commission will not require public power or other joint participation in a transmission project in order for investment in a project to be eligible for incentives. They assert that conditioning a grant of any incentive rate treatments upon a robust, collaborative and open joint and regional planning process with all LSEs in the region and mandating compensation or credits for public power systems transmission facilities would better promote the Commission's goal under section 219.[164] Similarly, APPA/NRECA state that public power participation ensures that the lowest cost facilities are built, provide cash flow, and reduce uncertainty, thereby reducing the overall need for incentive rate treatments.[165] NECOE and APPA/NRECA also argue that public utilities should be required to offer joint ownership opportunities as a condition to receiving incentives. NECOE asserts that merely encouraging transmission owners to seek participation by public power has not worked in New England, thereby denying ratepayers the low cost benefits of public power. NECOE further contends that the exclusion of non-transmission owner investment from network upgrades violates Order No. 2000's open-architecture principles.[166] At a minimum, NECOE recommends that the Commission should require incentive applicants to state whether they have sought potential LSE co-investors, including public and consumer-owned utilities and where co-investors were sought but not permitted to participate, the proponent of an incentive should be required to explain why this was the case.[167]

2. Commission Determination

102. The Final Rule determined that the Commission would not condition recovery of incentives on the type of business structure and stated that the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates as part of a proposal for incentives for a particular joint project.[168] While the Commission encourages public power participation, we will not require such participation as a condition of any proposed incentive rate treatment. As we state elsewhere in this order, the Commission cannot compel investment or *certain* types of investment. Our focus in this rule is to provide incentives that will facilitate voluntary investments by utilities. However, the Commission will look favorably on an

[158] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 192.

[159] *Public Service Comm'n of New York* v. *FERC*, 642 F.2d 1335 (D.C. Cir. 1980) (''we cannot accept the proposition that because a company files for higher rates, it bears the burden of proof on those portions of its filing that represent no departure from the status quo* * *. The emphasis is on making the petitioner justify the changes in rates, not the constant elements'') (*PSC of N.Y.*); *City of Winnfield, La.* v. *FERC*, 744 F.2d 871 (D.C. Cir. 1984) (''The statutory obligation of the utility * * * is not to prove the continued reasonableness of *unchanged* rates or *unchanged* attributes of its rate structure'') (*Winnfield*).

[160] This clarification is also consistent with Commission precedent:

Protesters object to this option because of a concern that it may permit certain transmission owners to continue to overrecover their cost-of-service. However, this option provides just and reasonable cost recovery for the RTEP upgrades, and provide the necessary incentive for TOs to complete quickly the construction of RTEP projects that are essential to the efficient operation of PJM. As we said in the NYISO proceeding, if a concern arises regarding over-recovery of transmission costs, such parties are free to seek relief by filing a complaint with the Commission pursuant to section 206 of the FPA *Allegheny Power System Operating Co.*, 111 FERC ¶ 61,308, at P 46 (2005), *order on reh'g and clarification*, 115 FERC ¶ 61,156 (2006).

[161] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354.

[162] *Id.* The Commission did not require a consortium approach that includes public power and other entities for new investment because it would be more appropriate for applicants to fashion proposals tailored to the specific circumstances and needs of a particular project. *Id.* P 356–57.

[163] TAPS at 22.

[164] TDU Systems at 34–35.

[165] APPA/NRECA at 51.

[166] NECOE at 9, citing *Carolina Power and Light Cos.*, 95 FERC ¶ 61,282 at 61,995 (2001).

[167] NECOE at 5.

[168] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354.

incentive request that includes public power joint ownership. A wide variety of entities, such as merchant companies, private equity participants, and pool administrators can potentially build transmission infrastructure. In the context of a rule to provide rate incentives for the construction of new transmission and to encourage deployment of technologies to increase the capacity and efficiency of existing transmission facilities, we do not believe that mandating an opportunity for public power participation is necessary nor do we believe that failure to do so would be unduly discriminatory. However, we note that the Commission has initiated a rulemaking in Docket Nos. RM05–17–000 and RM05–25–000 to investigate necessary reforms to its existing pro *forma* OATT.[169] Among the reforms under consideration is to require all jurisdictional public utilities to establish regional transmission planning open to all participants in a region—including public entities. We believe that the OATT reform rulemaking is a more appropriate forum to consider any issues or allegations regarding undue discrimination with regard to public power participation in transmission expansion decisions. Accordingly, we will not restrict eligibility for incentive rate treatment to projects that allow public power participation.

L. Other Issues

103. Parties request rehearing on a number of other issues discussed below.

1. Recovery of Costs of Abandoned Facilities

104. In the Final Rule, the Commission allowed applicants to seek recovery of 100 percent of prudently-incurred costs associated with abandoned transmission projects due to factors beyond the control of the public utility. The purpose of the incentive was to reduce the risk associated with potential upgrades or other improvements to the transmission system.

105. TDU Systems assert that the Commission should clarify that it would allow prudently incurred abandoned plant costs under limited circumstances. They contend that applicants for the incentive rate treatment that allows recovery of prudently-incurred abandoned plant costs should be required to demonstrate that, as a precondition to receiving the incentive, they will suffer cash flow problems if such a recovery was not allowed.[170] APPA/NRECA argue that the Commission should allow the incentive of abandoned cost recovery only on the condition that the public utility has engaged in open, regional transmission planning process to ensure some balance between the interests of shareholders and ratepayers. They claim that the Commission wrongly relied on its granting of incentive rate treatment to American Transmission Company as a basis for this incentive without recognizing that the project was the result of joint planning.[171] Therefore, they assert that the Commission should not ask customers to pay for abandoned projects that they never had an opportunity to consider in the first instance.

106. We decline to specify any particular demonstration that an applicant must make to justify recovery of abandoned plant cost beyond the required nexus test described earlier. Also, as discussed in the prior section on public power participation, we do not intend to mandate public power participation as a pre-requisite for any particular transmission rate treatment in this rule—including recovery of abandoned plant costs. We note that in a recent case involving incentives,[172] the Commission expressly conditioned its approval of incentives (including a request for recovery of costs associated with any abandonment of the project) upon the project being included in the PJM regional transmission expansion plan.[173] For these reasons, we deny rehearing on this issue.

107. According to TDU Systems, the Commission must ensure that there is no double recovery of costs in instances in which other incentives are allowed for an abandoned project. In the event the applicant receives the ROE incentive and the abandoned plant incentive rate treatment, TDU Systems argue there should be an offset of the rate impacts of these incentives to avoid over-recovery of costs so that the incentive can be provided at the least reasonable cost to consumers.[174] As described earlier in this order, we intend to evaluate any incentives requested as a package. To the extent that certain requested rate treatments have the effect of lowering the risk of a particular project, the Commission will take that into account in establishing an appropriate equity return for the project.

2. Prudently Incurred Costs

108. MISO TOs request clarification that limited section 205 filings are permissible for the recovery of costs of prudently-incurred costs necessary to comply with mandatory reliability standards in section 215.[175] MISO TOs argue that these costs may be imposed on transmission owners pursuant to statutory requirements and that without this clarification, they may be subject to extensive and expensive litigated cases, thereby discouraging utilities from recovering these costs that Congress authorized them to recover.

109. We agree that rapid processing of the recovery of mandatory reliability costs will facilitate more timely investment in these important projects. Therefore, we clarify that applicants may file to recover these costs in limited section 205 filings.

3. Regional Planning

110. Parties contend that any public utility seeking incentive rates for its new transmission project should be required to demonstrate that the project was formulated through an open, regional planning process. Industrial Consumers assert that conditioning the granting of incentives upon the inclusion of a proposed transmission project in a regional planning process is critical to satisfying section 219's requirements to demonstrate customer benefit and promote economically efficient transmission. They claim that a coordinated regional planning process that considers the relative costs and benefits of multiple projects provides an optimal forum for determining least-cost solutions and avoiding unnecessary duplication of expenditures.[176] Similarly, NARUC and TAPS argue that no incentive should be available for projects that are to be sited in regions that plan regionally but which bypass the regional planning processes, noting that the Commission is proposing to require all jurisdictional public utilities to engage in regional planning in other Commission proceedings.[177] Further, TDU Systems argue that nothing in section 219 suggests that the Commission may not impose a regional planning requirement and that making regional planning process a threshold requirement for incentive applications would be congruent with the mandate of section 219 to promote reliable and economically efficient transmission and

[169] *See* OATT Reform NOPR, *supra* note 63.

[170] TDU Systems at 38.

[171] APPA/NRECA, 44–45. *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 1, 116, 122, 131; *American Transmission Co., LLC*, 105 FERC ¶ 61,388 (2003).

[172] *Allegheny Energy, Inc.*, 116 FERC ¶ 61,059 (2006), *reh'g pending*.

[173] *American Electric Power Service Corp.*, 116 FERC ¶ 61,059 (2006), *reh'g pending*.

[174] TDU Systems at 38.

[175] MISO TOs at 4–5.

[176] Industrial Consumers at 11.

[177] NARUC at 6; TAPS at 7.

generation of electricity.[178] APPA/NRECA also contend that the Commission has broad discretion in deciding particular incentives and that a regional planning requirement would harmonize section 219 with the objectives of section 217(b) to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of LSEs. They also argue that the imposition of regional planning as a threshold requirement for incentive applicants is required by the mandate of section 219.[179]

111. The Final Rule grants a rebuttable presumption that projects resulting from regional planning qualify for incentive rate treatments, and we affirm that finding as discussed above. We will not, however, limit incentive rate treatments to projects that result from regional planning processes. While the Commission agrees that there are substantial benefits to be derived from regional planning, there may be transmission projects that arise outside of the context of a regional plan that help to ensure reliability or reduce the costs of delivered power and which deserve incentive rate treatment. Although the Commission has proposed to require regional planning as part of its OATT reform effort,[180] we note that many utilities are in regions in which no formal regional planning process exists at this time. However, as we stated in the Final Rule, and as modified by this order, projects are not entitled to a rebuttable presumption if they have not gone through a regional planning process, or have not received construction approval from an appropriate state commission or siting authority.[181] Applicants seeking incentives for such projects must independently demonstrate that the project will maintain reliability or reduce congestion.

4. CWIP

112. Because the long lead times required to plan and construct new transmission can negatively affect cash flow and the ability of a utility to attract capital at reasonable prices, the Final Rule allows public utilities to propose including 100 percent CWIP in rate base and expensing pre-commercial operations costs associated with new transmission investment.[182]

[178] TDU Systems at 9–10.

[179] APPA/NRECA at 16–19.

[180] OATT Reform NOPR, supra note 63.

[181] In addition, and as modified by this order, an applicant may also rely upon the Commission's siting authority for meeting the requirements of section 219(a).

[182] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 115–22.

113. TDU Systems assert that the Commission should only allow 100 percent recovery CWIP and pre-commercial operations costs in the event the applicant shows that the transmission project will take more than four years to complete and that the applicant should have to demonstrate a regional need for the project to ensure that consumers receive measurable benefits.[183] In addition, TDU Systems contend that, with respect to pre-commercial expenses, the Commission should: (1) Ensure that these costs are not later capitalized in subsequent rate filings; and (2) limit the pre-commercial costs to be expensed to planning, siting and environmental costs so that costs that raise inter-generational equity concerns, such as the design and construction of facilities, are not included.[184]

114. We decline to establish any generic restrictions on the types of transmission projects or construction periods in order for a project to qualify for CWIP treatment under this rule. We leave to the applicant's discretion whether the construction project is of sufficient size to merit making a rate request to the Commission seeking to include CWIP in rate base or to expense pre-commercial operations costs. There may be reasons that justify seeking CWIP for projects with relatively short construction schedules e.g., a project may take only a few years to build but rates will not go into effect for a number of additional years because the project can not recover costs until other projects are built, and therefore CWIP recovery is justified. We clarify that the Commission's review process under section 205 will include a review to determine that the applicant does not double recover these costs. The Final Rule's definition of costs approved by the Commission to be recoverable as pre-certification costs in account 183, *i.e.*, preliminary survey and investigation costs,[185] does not include facility costs and therefore should not raise the inter-generational issues of concern to TDU Systems.

115. Finally, while CWIP and abandoned plant are characterized as ''incentive-based rate treatments'' in the Final Rule, we clarify that both of these rate mechanisms have been found previously to be just and reasonable under the Commission's authority pursuant to section 205.[186] More importantly, these are rate treatments which may be needed (and requested) in advance of a project being approved through a regional planning process or receiving any necessary siting approvals. To the extent an applicant demonstrates that the incentives sought (i.e., CWIP and abandoned plant) are tailored to address the demonstrable risks and challenges of the applicant, we will permit recovery of such prudently-incurred costs.

[183] TDU Systems at 9–10.

[184] *Id.* at 37.

[185] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 122 and n 82.

[186] *See, e.g., American Electric Power Service Corp.*, 116 FERC ¶ 61,059, at P 55 (2006), *reh'g pending* (allowing recovery of 100 percent CWIP); *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058, at P 74 (2006), *reh'g pending; American Transmission Co., L.L.C.,* 105 FERC ¶ 61,388, at P 27 (order establishing hearing and settlement judge procedures concerning, inter alia, the company's proposal for recovery of 100 percent CWIP), *order dismissing reh'g and approving settlement,* 107 FERC ¶ 61,117 (2004); *Boston Edison Co.,* 109 FERC ¶ 61,300 (2004), *order on reh'g,* 111 FERC ¶ 61,266 (2005) (recovery of 50 percent CWIP); *Southern California Edison Co.,* 112 FERC ¶ 61,014, at P 58–61, reh'g denied, 113 FERC ¶ 61,143, at P 9–15 (2005) (granting recovery of 100 percent of prudently incurred abandoned or cancelled plant costs); *New England Power Co.,* Opinion No. 295, 42 FERC ¶ 61,016, at 61,068, 61,081–83 (recovery of 50 percent of prudently incurred cancelled plant costs), *order on reh'g,* 43 FERC ¶ 61,285 (1988); *Public Service Co. of New Mexico,* 75 FERC ¶ 61,266, at 61,859 (1996), *order approving settlement,* 87 FERC ¶ 61,040 (1999) (50 percent recovery of cancelled plant costs).

116. For example, where an applicant has satisfied our nexus requirement and has been granted authority to recover CWIP or abandoned plant, and subsequently the applicant's project is, for example, unable to obtain state or federal siting authority (and thus no showing is made with respect to ensuring reliability or reducing the cost of delivered power by reducing congestion because the applicant was relying upon those processes) we would not require refunds for the costs already prudently-incurred by the applicant. To require refunds in such circumstances would be contrary to our long-standing policy, which permits recovery of all prudently-incurred costs.[187]

5. Reporting Requirement: FERC–730

117. The Final Rule adopted an annual reporting requirement, FERC–730, for utilities that receive incentive rate treatment for specific transmission projects. The annual reporting requirement includes projections and

[187] The Commission ''has applied the 'prudence' test to determine the recoverability of a utility's expenses. Under this test [a utility] is entitled to recover its costs from consumers if it acted 'prudently' in incurring those costs, or stated conversely, [a utility] may not recover its costs if those costs were incurred 'imprudently.' '' *Connecticut Yankee Atomic Power Co.*, 108 FERC ¶ 61,212, at P 42 (2004), quoting *Violet* v. *FERC*, 800 F.2d 280, 282 (1st Cir. 1986). *See also, e.g., City of New Orleans* v. *FERC*, 67 F.3d 947 (D.C. Cir. 1995) (citing *Violet* v. *FERC*)).

related information that detail the level of transmission investment.[188]

118. TAPS argues that FERC–730's tracking of capital spending is misdirected by failing to identify how much consumers are spending as incentive rate treatments and what they are getting in return. TAPS recommends that the Commission expand FERC–730 to include budgeted amounts by project on an annual basis, segregation of generation or distribution investments, a listing of which network service customers are predominantly paying for the project costs and the expected differential cost to consumers of each project's approved above-cost incentives.[189]

119. As the Commission explained in the Final Rule, the purpose of the FERC–730 reporting requirement is not to provide a quantitative measure of the consumer benefits that result from transmission infrastructure investments. In the proceeding approving incentives and recovery of the costs of incentives in rates, the Commission will determine whether proposed projects meet the requirements of section 219 and thereby provide consumer benefits and also set metrics to ensure those benefits are justified on an on-going basis. Therefore no further quantitative tracking of consumer benefits or expected differential costs to consumers is necessary. We repeat and affirm the Final Rule's statement that year-by-year capital spending estimates are not necessary for each individual project listed since the goal of the rule is not to ensure the achievement of annual capital spending targets but rather to ensure the overall projects are completed, and if not, the reasons for delay.

120. We will not limit the capital spending information requested from account numbers 350 through 359[190] to only investment in the transmission function, and exclude transmission investment in the generation or distribution functions. Capital investment in transmission facilities that interconnect generation facilities are ensuring reliability, and therefore are meeting the requirements of section 219. Accordingly, it is appropriate to include these amounts in transmission investment. Likewise, capital investment in lower voltage transmission facilities that are classified as part of the distribution function also accomplish the reliability and congestion reduction requirements of section 219 and therefore should be included in the survey of transmission investment. We see no need to require additional information on which customers pay for investment projects and the differential cost impact of the incentives. The purpose of FERC–730 is restricted to information on progress toward meeting the requirements of section 219. Customer allocation of cost responsibility is beyond the scope of that provision, and therefore that information does not need to be collected.

6. Miscellaneous

121. TDU Systems and APPA/NRECA argue that no incentives should be approved for projects that already have a binding commitment to build, including commitments under RTO arrangements, or for which applicants are obligated to build by statute, regulation or order.[191]

122. In general, we do not consider that contractual commitments or mandatory projects, such as section 215 reliability projects, disqualify a request for incentive-based rate treatment. Provided applicants are able to demonstrate they meet the requirements of section 219, including establishing the required nexus between the requested incentive and the investment, they may qualify for incentive-based rate treatments. A prior contractual commitment or statute may have a bearing on our nexus evaluation of individual applications.

123. EEI requests clarification that an applicant or group of applicants may propose rate incentives for a group of interrelated projects rather than for each single project individually, and thereby reduce the Commission burden.[192]

124. We clarify that applicants may propose incentives as a group, and note that such a group application process has been used by groups of transmission owners that are members of RTOs. With this clarification, we believe that revision of § 35.35(d) is unnecessary.

125. TAPS asserts that the Final Rule failed to explicitly provide that applicants' proposed incentives will be modified when doing so will advance the customer-benefiting objectives of section 219. For example, TAPS argues that in order to modify the investment to which incentives will apply, an applicant may propose an incentive-worthy, congestion-reducing, new line packaged with mundane existing facility replacements that have already been committed to and do not advance the objectives of section 219.[193] In such a case, TAPS argues that the Commission should be able to modify the proposal to target incentives to the new line alone.

126. We do not consider this rulemaking to be the proper forum to assess whether a hypothetical application would meet the requirements of section 219 and Order No. 679. The Commission will determine whether incentive applications are just and reasonable based on the specific facts and circumstances of each proposal.

127. TDU Systems request clarification that metrics are required because certain statements in the Final Rule imply metrics are optional.[194] To the extent the use of metrics determines that a project does not provide the anticipated benefits, ratepayers should receive refunds based on the monetary value of the incentive, according to TDU Systems.

128. We clarify that applicants are required to propose metrics in their incentive applications. However, it is not the Commission's intention to approve incentive rate treatments ''subject to refund.'' To the extent that a customer has a reason to believe that any rate that has been approved by the Commission is no longer just, reasonable, and not unduly discriminatory or preferential, they will need to file an appropriate complaint under section 206.

129. TAPS contends that the Commission is not statutorily free to rule out symmetrical, *i.e.* performance-based approaches to setting an appropriate return regardless of whether they are sponsored by incentive applicants or recommended with appropriate support by intervenors. TAPS states that section 219 expressly provides that incentive programs may be performance-based and has long been a foundation for Commission incentive rate policy.[195] SMUD asserts that the Commission failed to explain its departure from the 1992 Policy Statement that symmetry is an inherent part of all incentive ratemaking.[196]

130. The purpose of this rule is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. The primary focus of the rule is necessarily on

[188] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 367–76.

[189] TAPS at 29–31.

[190] 18 CFR part 101.

[191] APPA/NRECA at 4; TAPS at 35.

[192] EEI at 6.

[193] TAPS at 12.

[194] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 36 (''an applicant may propose periodic progress assessments * * *'').

[195] TAPS at 28.

[196] SMUD at 9–10.

investment. However, while the Final Rule declined to adopt generic performance-based ratemaking measures, we did encourage the industry to work on developing performance-based ratemaking proposals. While we agree that section 219 does not rule out symmetrical approaches to return, to the extent applicants or intervenors propose performance-based rate treatments under section 219, they must justify their proposals in terms of their capability to attract investment and either ensure reliability or reduce the cost of delivered power by reducing congestion.

131. TAPS asserts that the Commission cannot determine if an incentive will be non-discriminatory, as required under section 219(d), unless it ascertains what ratepayer classes are subject to paying for the incentive. TAPS also claims the Commission needs to consider whether an incentive request should be conditioned on geographically broadened cost spreading in order to determine whether the requested incentives can be better formulated to advance the consumer benefits of section 219. TAPS further argues that the Commission should state its willingness to consider in declaratory petition proceedings how costs will be allocated for the subject facilities and whether altering that treatment should be part of the incentive program.[197] TDU Systems assert that the Commission must require roll-in of new and existing rates to encourage investment.

132. We repeat the finding in the Final Rule that the section 205 proceedings addressing recovery of the costs of incentive-based rate treatments are the appropriate forum for determining whether the resulting rates are just, reasonable and non-discriminatory, and therefore are the appropriate proceedings to consider cost allocation and rate design issues.[198] The primary purpose of the declaratory petition proceeding is to determine if the proposed incentives meet the requirements of section 219, and therefore cost allocation and rate design issues will not be considered. Finally, we consider rate design issues, such as roll-in of rates to beyond the scope of this proceeding, and therefore affirm the Final Rule's determination to not require roll-in of rates.[199]

133. Southern Companies assert that the Commission's routine imposition of a five-month suspension of rates is a disincentive to the construction of new transmission infrastructure, claiming that delaying the effective date of a rate change forces the utility to absorb costs associated with new facilities and reduces the utility ROE.[200]

134. The Commission addressed this concern in the Final Rule by stating that we will not revise our suspension policy in this proceeding. We affirm the Final Rule's finding that utilities should raise concerns with the Commission's suspension policy in our pre-filing process.

135. Energy Financing requests clarification that its proposed performance-based financing option for transmission investment is not excluded as an alternative method of achieving the Commission's and Congress' goal of encouraging more transmission investment, or in the alternative, it seeks rehearing arguing that alternative financing methodologies are viable vehicles to increase transmission investment, in lieu of or in addition to the incentives identified in the Final Rule.[201] Energy Financing's proposal concerns how a project is financed rather than an incentive-based rate treatment. We do not consider it an alternative to the incentive-based rate treatments specified in § 35.35. Also, we can not make a determination as to whether the option will increase transmission investment because Energy Financing has not provided any information to indicate that its option is having the purported effect on investment. For these reasons, we deny rehearing on this issue.

136. Finally, the introductory text in § 35.35(d)(1) is revised to delete redundant language.

IV. Information Collection Statement

137. Order No. 679 contains information collection requirements for which the Commission obtained approval from the Office of Management and Budget (OMB). The OMB Control Number for this collection of information is 1902–0203. This order denies most rehearing requests, clarifies the provisions of Order No. 679, and grants rehearing on only three minor issues. This order does not make substantive modifications to the Commission's information collection requirements and, accordingly, OMB approval for this order is not necessary. However, the Commission will send a copy of this order to OMB for informational purposes.

V. Document Availability

138. 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.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

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

140. User assistance is available for eLibrary and the FERC's Web site during normal business hours from our Help line at (202) 502–8222 or the Public Reference Room at (202) 502–8371 Press 0, TTY (202) 502–8659. E-Mail the Public Reference Room at *public.referenceroom@ferc.gov.*

VI. Effective Date

141. Changes to Order No. 679 made in this order on rehearing will become effective on February 9, 2007.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Magalie R. Salas,

Secretary.

■ In consideration of the foregoing, the Commission amends part 35 of Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 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. Section 35.35 is amended by:
■ a. Revising the third sentence in paragraph (d) introductory text ,
■ b. Revising paragraph (d)(1) introductory text;
■ c. Revising paragraph (i); and
■ d. Adding a new paragraph (j) to read as follows:

§ 35.35 Transmission infrastructure investment.

* * * * *

[197] TAPS at 17–18.

[198] *E.g.*, Order No. 679, FERC Stats. & Regs. ¶ 31,622 at P 81.

[199] *Id.* P 192.

[200] Southern Companies at 19–20.

[201] Energy Financing at 4–5.

(d) *Incentive-based rate treatments for transmission infrastructure investment.* * * * The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that the *total* package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that resulting rates are just and reasonable. * * *

(1) For purposes of this paragraph (d), incentive-based rate treatment means any of the following:

* * * * *

(i) *Rebuttable presumption.* (1) The Commission will apply a rebuttable presumption that an applicant has demonstrated that its project is needed to ensure reliability or reduces the cost of delivered power by reducing congestion for:

(i) A transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or

(ii) A project that has received construction approval from an appropriate state commission or state siting authority.

(2) To the extent these approval processes do not require that a project ensures reliability or reduce the cost of delivered power by reducing congestion, the applicant bears the burden of demonstrating that its project satisfies these criteria.

(j) *Commission authorization to site electric transmission facilities in interstate commerce.* If the Commission pursuant to its authority under section 216 of the Federal Power Act and its regulations thereunder has issued one or more permits for the construction or modification of transmission facilities in a national interest electric transmission corridor designated by the Secretary, such facilities shall be deemed to either ensure reliability or reduce the cost of delivered power by reducing congestion for purposes of section 219(a).

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix A

Requests for Rehearing

American Public Power Association and National Rural Electric Cooperative Association (together, APPA/NRECA)
Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition, Southeast Electricity Consumers Association, and Southwest Industrial Customer Coalition (collectively, Industrial Consumers).
Connecticut Department of Public Utility Control, the Massachusetts Municipal Wholesale Electric Company, the Connecticut Municipal Electric Energy Cooperative, the New Hampshire Electric Cooperative, the Maine Public Utility Commission, and the New England Conference of Public Utility Commissioners (collectively, New England Commissions).
Edison Electric Institute (EEI).
Energy Financing, Inc. (Energy Financing).
Midwest ISO Transmission Owners (MISO TOs).
National Association of Regulatory Utility Commissioners (NARUC).
New England Consumer-Owned Entities (NECOE).
Public Utilities Commission of the State of California (California Commission).
Sacramento Municipal Utility District (SMUD).
Southern California Edison Company (SoCal Edison).
Southern Company Services, Inc., on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company (collectively, Southern Companies).
Transmission Access Policy Study Group (TAPS).
Transmission Dependent Utility Systems (TDU Systems).
Xcel Energy Services, Inc. (Xcel).

[FR Doc. E6–22693 Filed 1–9–07; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 510, 520, and 558

New Animal Drugs; Change of Sponsor

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule; technical amendment.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect a change of sponsor for 14 approved new animal drug applications (NADAs) from ADM Animal Health & Nutrition Division to ADM Alliance Nutrition, Inc.

DATES: This rule is effective January 10, 2007.

FOR FURTHER INFORMATION CONTACT: David R. Newkirk, Center for Veterinary Medicine (HFV–100), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–827–6967, e-mail: *david.newkirk@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION: ADM Animal Health & Nutrition Division, 1000 North 30th St., Box 1C, Quincy, IL 62305–3115 has informed FDA that it has transferred ownership of, and all rights and interest in, the following 14 approved NADAs to ADM Alliance Nutrition, Inc., 1000 North 30th St., Quincy, IL 62305–3115:

Application No.	Trade name(s)
048–480	Chloratet 50
065–256	Chlortet-Soluble-O
091–582	Gilt Edge TYLAN Mix
107–957	TYLAN 20 Sulfa-G, TYLAN 40 Sulfa-G
108–484	HFA Tylosin–10 Plus Sulfa
110–045	Good-Life TYLAN 10 Premix
110–439	HFA Hygromix 2.4 Medicated Premix
118–877	Ban-A-Worm Pyrantel Tartrate Ton Pack
128–411	TYLAN 5 Sulfa Premix
131–956	TYLAN Sulfa-G
131–957	TYLAN 10, TYLAN 20, TYLAN 40, TYLAN 5
132–448	FLAVOMYCIN
133–490	Ban-D-Wormer II BANMINTH
140–842	Hygromix 2.4 Premix

Accordingly, the agency is amending the regulations in 21 CFR 520.445b, 558.95, 558.128, 558.274, 558.485, 558.625, and 558.630 to reflect the transfer of ownership and a current format.

In addition, ADM Animal Health & Nutrition Division is no longer a sponsor of an approved application. Accordingly, 21 CFR 510.600(c) is being amended to remove entries for the firm.

This rule does not meet the definition of ''rule'' in 5 U.S.C. 804(3)(A) because it is a rule of ''particular applicability.'' Therefore, it is not subject to the congressional review requirements in 5 U.S.C. 801–808.

List of Subjects

21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

21 CFR Part 520

Animal drugs.