DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 385

[Docket Nos. RM95–8–000 and RM94–7–001; Order No. 888]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

Issued April 24, 1996.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing a Final Rule requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. The Final Rule also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Federal Power Act section 211 transmission services. The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.

EFFECTIVE DATE: This Final Rule will become effective on July 9, 1996.

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I. Introduction/Summary

Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.[1] The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce. A second critical aspect of the rules is to address recovery of the transition costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced.

In the year since the proposed rules were issued,[2] the pace of competitive changes in the electric utility industry has accelerated. By March of last year, 38 public utilities had filed wholesale open access transmission tariffs with the Commission. Today, prodded by such competitive changes and encouraged by our proposed rules, 106 of the approximately 166 public utilities that own, control, or operate[3] transmission facilities used in interstate commerce have filed some form of wholesale open access tariff. In addition, since the time the proposed rules were issued, numerous state regulatory commissions have adopted or are actively evaluating retail customer choice programs or other utility restructuring alternatives. These events have been spurred by continuing pressures in the marketplace for changes in the way electricity is bought, sold, and transported. Increasingly, customers are demanding the benefits of competition in the growing electricity commodity market.

The Commission estimates the potential quantitative benefits from the Final Rule will be approximately $3.8 to $5.4 billion per year of cost savings, in addition to the non-quantifiable benefits that include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. The continuing competitive changes in the industry and the prospect of these benefits to customers make it imperative that this Commission take the necessary steps within its jurisdiction to ensure that all wholesale buyers and sellers of electric energy can obtain non-discriminatory transmission access, that the transition to competition is orderly and fair, and that the integrity and reliability of our electricity infrastructure is maintained.

In this Rule, the Commission seeks to remedy both existing and future undue discrimination in the industry and realize the significant customer benefits that will come with open access. Indeed, it is our statutory obligation under sections 205 and 206 of the Federal Power Act (FPA) to remedy undue discrimination.

To do so, we must eliminate the remaining patchwork of closed and open jurisdictional transmission systems and ensure that all these systems, including those that already provide some form of open access, cannot use monopoly power over transmission to unduly discriminate against others. If we do not take this step now, the result will be benefits to some customers at the expense of others. We have learned from our experience in the natural gas area the importance of addressing competitive transition issues early and with as much certainty to market participants as possible.

Accordingly, in this proceeding and in the accompanying proceeding on OASIS, the Commission, pursuant to its authorities under sections 205 and 206 of the FPA:

- Requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce
- To file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;
- To take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs;
- To develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications;
- Clarifies Federal/state jurisdiction over transmission in interstate commerce and local distribution and provides for deference to certain state recommendations; and
- Permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services.

Open Access

The Final Rule requires public utilities to file a single open access tariff that offers both network, load-based service and point-to-point, contract-based service. The Rule contains a pro forma tariff that reflects modifications to the NOPR's proposed terms and conditions and also permits variations for regional practices. All public utilities subject to the Rule, including those that already have tariffs on file, will be required to make section 206 compliance filings to meet the new pro forma tariff non-price minimum terms and conditions of non-discriminatory transmission. Utilities may propose their own rates in a section 205 compliance filing.

The Rule provides that public utilities may seek a waiver of some or all of the requirements of the Final Rule. In addition, non-public utilities may seek a waiver of the tariff reciprocity provisions.

The Final Rule does not generically abrogate existing requirements contracts, but will permit customers and public utilities to seek modification, or termination, of certain existing requirements contracts on a case-by-case basis. As to coordination arrangements and contracts, the Rule finds that these arrangements and contracts may need to be modified to remove unduly discriminatory transmission access and/or pricing provisions. Such arrangements and agreements include power pool agreements, public utility

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[1] These rules are the rules on open access and stranded costs in the above dockets (FERC Stats. & Regs. ¶ 31,036), and an accompanying rule on Open Access Same-Time Information System and Standards of Conduct (OASIS Final Rule) (FERC Stats. & Regs. ¶ 31,037) being issued contemporaneously. The Commission also is issuing contemporaneously a notice of proposed rulemaking on capacity reservation open access transmission tariffs in Docket No. RM96–11–000, FERC Stats. & Regs. ¶ 32,517. These final rules and proposed rule are being published concurrently in the Federal Register.

[2] On March 29, 1995, the Commission issued two notices of proposed rulemaking concerning open access transmission and stranded cost recovery. Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 60 FR 17662 (April 7, 1995), FERC Stats. & Regs. ¶ 32,514 (1995). On December 13, 1995, the Commission issued a notice of proposed rulemaking on information systems. Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking, 60 FR 66182 (December 21, 1995), FERC Stats. & Regs. ¶ 32,516 (1995).

[3] The Commission's notice of proposed rulemaking in the above dockets proposed to apply the proposed requirements to public utilities that own and/or control facilities used for the transmission of electric energy in interstate commerce. "Own and/or control" is intended to include public utilities that "operate" facilities used for the transmission of electric energy in interstate commerce. However, we have modified the Final Rule regulatory text to remove any ambiguity.

holding company agreements, and certain bilateral coordination agreements. The Rule provides guidance and timelines for modifying unduly discriminatory coordination arrangements and contracts, and specifies when the members of such arrangements must begin to conduct trade with each other using the same open access tariff offered to others. The Rule also provides guidance regarding the formation of independent system operators (ISOs).

The Rule does not require any form of corporate restructuring, but will accommodate voluntary restructuring that is consistent with the Rule's open access and comparability policies.

As discussed in the NOPR, not all owners or controllers of interstate transmission facilities are subject to the Commission's jurisdiction under sections 205 and 206 of the FPA and therefore are not subject to this Rule's open access requirements. Therefore, the Final Rule retains the proposed reciprocity provision in the pro forma tariff. Without such a provision, non-open access utilities could take advantage of the competitive opportunities of open access, while at the same time offering inferior access, or no access at all, over their own facilities. Thus, open access utilities would be unfairly burdened. We note that some non-jurisdictional utilities have expressed an interest in a mechanism for obtaining a Commission determination that their transmission tariffs satisfy the reciprocity provisions in the pro forma tariffs, and we provide such a mechanism in the Rule.

The Final Rule does not generically provide for market-based generation rates. Although the Rule codifies the Commission's prior decision that there is no generation dominance in new generating capacity, intervenors in cases may raise generation dominance issues related to new capacity. In addition, to obtain market-based rates for existing generation, we will continue to require public utilities to show, on a case-by-case basis, that there is no generation dominance in existing capacity. Further, in all market-based rate cases, we will continue to look at whether an applicant and its affiliates could erect other barriers to entry and whether there may be problems due to affiliate abuse or reciprocal dealing.

Finally, contemporaneously with this Rule the Commission issues an NOPR on capacity reservation tariffs as an alternative, and perhaps superior, means of remedying undue discrimination.

Transmission/Local Distribution

The Rule clarifies the Commission's interpretation of the Federal/state jurisdictional boundaries over transmission and local distribution. While we reaffirm our conclusion that this Commission has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, we nevertheless recognize the very legitimate concerns of state regulatory authorities as they contemplate direct retail access or other state restructuring programs. Accordingly, we specify circumstances under which we will give deference to state recommendations. Although jurisdictional boundaries may shift as a result of restructuring programs in wholesale and retail markets, we do not believe this will change fundamental state regulatory authorities, including authority to regulate the vast majority of generation asset costs, the siting of generation and transmission facilities, and decisions regarding retail service territories. We intend to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies.

Stranded Costs

With regard to stranded costs, the Final Rule adopts the Commission's supplemental proposal. It will permit utilities to seek extra-contractual recovery of stranded costs associated with a limited set of existing (executed on or before July 11, 1994) wholesale requirements contracts and provides that the Commission will be the primary forum for utilities to seek recovery of stranded costs associated with retail-turned-wholesale transmission customers. It also will allow utilities to seek recovery of stranded costs caused by retail wheeling only in circumstances in which the state regulatory authority does not have authority to address retail stranded costs at the time the retail wheeling is required. The Rule retains the revenues lost approach for calculating stranded costs and provides a formula for calculating such costs.

Environmental Issues

The Commission has prepared a Final Environmental Impact Statement (FEIS) evaluating the possible environmental consequences of changes in the bulk power marketplace expected to occur as a result of the open access requirements of this Final Rule. The FEIS focuses, as do most commenters, on possible increases in emissions of nitrogen oxides (NO_X) from certain fossil-fuel fired generators, which could affect air quality in the producing region and in areas to which these emissions may be carried.

In response to comments on the Draft EIS, the Commission performed numerous additional studies. The FEIS finds that the relative future competitiveness of coal and natural gas generation is the key variable affecting the impact of the Final Rule. If competitive conditions favor natural gas, the Rule is likely to lead to environmental benefits. Both EPA and the Commission staff believe this projected scenario is the more likely one. If competitive conditions favor coal, the Rule may lead to small negative environmental impacts. However, even using the most extreme, unlikely assumptions about the future of the industry, the negative consequences are not likely to occur until after the turn of the century. Because the impacts will remain modest at least until 2010, there is no need for an interim mitigation program. In addition, even if the data showed more significant negative consequences requiring mitigation, the Commission does not have the statutory authority under the Federal Power Act or the expertise to address this possible far-term problem. The Commission believes, however, that there is time for federal and state air quality authorities to address any potential adverse impact as part of a comprehensive NO_X regulatory program under the Clean Air Act.[4]

Despite our conclusions regarding the lack of environmental impacts expected to result from the Rule, the Commission has examined a wide variety of proposals for mitigating possible adverse effects. We share the view of most commenters that the preferred approach for mitigating increased NO_X emissions generally is a NO_X cap and trading regulatory program comparable to that developed by Congress to address sulfur dioxide emissions in the Clean Air Act Amendments of 1990.[5] The Commission has examined various means of establishing such a program, including use of existing federal authorities under the Clean Air Act, cooperative efforts by state and federal air quality regulators, and development of a new emissions regulatory program administered by the Commission under the Federal Power Act. The Commission has concluded that a NO_X regulatory program could best be developed and administered under the Clean Air Act, in cooperation with interested states, and offers to lend Commission support

[4] 42 U.S.C. 7401, *et seq.*

[5] 42 U.S.C.A. 7651b–e.

to that effort should it become necessary.

Conclusion

The Commission believes that the Final Rule will remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets.

II. Public Reporting Burden

The Open Access Final Rule and the Stranded Cost Final Rule specify filing requirements to be followed by public utilities that own, control or operate transmission facilities in interstate commerce in making non-discriminatory open access tariff filings and filings to recover legitimate, prudent and verifiable stranded costs. The information collection requirements of the final rules are attributable to FERC–516 ''Electric Rate Filings.'' The current total annual reporting burden for FERC–516 is 828,300 hours.

A. Docket No. RM95–8–000 (Open Access Final Rule)

The Open Access Final Rule requires public utilities filing non-discriminatory open access tariffs to provide certain information to the Commission. The Commission estimated that the public reporting burden for the information collection would average 300 hours per response. This estimate included time for reviewing the requirements of the Commission's regulations, searching existing data sources, gathering and maintaining the necessary data, completing and reviewing the collection of information, and filing the revised information. No comments on the burden estimate were received. Because the Final Rule adopts essentially the same information requirements that are contained in the proposed rule, we believe that the average filing burden is same for the Final Rule.

In the proposed rule, the Commission noted that there are approximately 328 public utilities, including marketers and wholesale generation entities. We initially estimated that 137 public utilities own, control or operate facilities used for the transmission of electric energy in interstate commerce, and would be subject to the filing requirements of the proposed rule. Upon further review, the Commission believes that approximately 166 public utilities will respond to the information collection. Accordingly, the public reporting burden is estimated to be 49,800 hours.

B. Docket No. RM94–7–001 (Stranded Cost Final Rule)

In the supplemental notice of proposed rulemaking, the Commission estimated that the information requirements of the proposed rule would not differ substantially from those contained in the initial proposed rule. In that notice, the Commission estimated that the public reporting burden for the information requirements contained in the proposed rule would be 50 hours per response with 10 responses annually. No comments on this filing burden were received. The information requirements adopted in the Stranded Cost Final Rule are not substantially different from those in the proposed rule. Therefore, the Commission concludes that there will be no additional public filing burden associated with the Stranded Cost Final Rule.

III. Background

In the NOPR, we set out a detailed statement of the events leading up to this rulemaking. We repeat that background here, updated to reflect what has happened since March 1995, and discuss why it is necessary to undertake regulatory reform in the electric industry at this time. We do so to provide the necessary backdrop to our action in adopting this Rule.

A. Structure of the Electric Industry at Enactment of Federal Power Act

The Federal Power Act was enacted in an age of mostly self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas. This structure of separate systems arose naturally due primarily to the cost and technological limitations on the distance over which electricity could be transmitted.

Through much of the 1960s, utilities were able to avoid price increases, but still achieve increased profits, because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices.[6] Thus, there was no pressure on regulatory commissions to use regulation to affect the structure of the industry.[7]

B. Significant Changes in the Electric Industry

In the late 1960s and throughout the 1970s, a number of significant events occurred in the electric industry that changed the perceptions of utilities and began a shift to a more competitive marketplace for wholesale power.[8] This was the beginning of periods of rapid inflation, higher nominal interest rates, and higher electricity rates.[9] During this time, consumers became concerned about higher electricity rates and questioned any price increases filed by utilities.[10]

During this same time frame, the construction of nuclear and other capital-intensive baseload facilities—actively encouraged by federal and some state governments—contributed to the continuing cost increases and uncertainties in the industry.[11] These investments were made based on the assumptions that there would be steady increases in the demand for electricity and continued large increases in the price of oil.[12] However, due to conservation and economic downturns, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity.[13] In addition, by the 1980s, the oil cartel collapsed, with a resulting glut of low-priced oil.[14] At the same time, inflation substantially increased the costs of these large

[6] Paul L. Joskow, Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation, 17 J. Law & Econ. 291, 312 (1974); *see also* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 11 (1988).

[7] *See* Joskow, *supra* at 312; *see also* Phillips, *supra* at 12.

[8] *See* Joskow, *supra* at 312; *see also* Phillips, *supra* at 12–13.

[9] *See* Joskow, *supra* at 312–13; *see also* Phillips, *supra* at 13. The Arab oil embargo resulted in significantly higher oil prices through the 1970s. *See* Richard J. Pierce, Jr., The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity, 132 U. Pa. L. Rev. 497, 501 (1984).

[10] *See* Joskow, *supra* at 313; *see also* Phillips, *supra* at 13.

[11] *See generally* Jersey Central Power & Light Company v. FERC, 810 F.2d 1168, 1171 (D.C. Cir. 1987).

[12] *Id.*

[13] *See* Pierce, *supra* at 503. By 1983, the Department of Energy had estimated that the sunk costs for canceled nuclear plants alone amounted to $10 billion. *Id.* at 498.

[14] *Id.*

baseload generating plants.[15] Surging interest rates further increased the cost of the capital needed to finance and capitalize these projects and completion schedules were significantly extended by, in part, more stringent safety and environmental requirements.[16]

As a result, expensive large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation.[17] Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation.[18] The rapidly increasing rates for electric power during this period, together with the opportunities provided by the Public Utility Regulatory Policies Act of 1978 (PURPA) (discussed *infra*), also prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers—primarily residential and commercial customers.

Consumers responded to these ''rate shocks'' by exerting pressure on regulatory bodies to investigate the prudence of management decisions to build generating plants, especially when construction resulted in cost overruns, excess capacity, or both. Between 1985 and 1992, writeoffs of nuclear power plants totalled $22.4 billion.[19] These writeoffs significantly reduced the earnings of the affected utilities.[20]

Delays in obtaining rate increases to reflect the effects of inflation further reduced investor returns. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.[21]

In addition to economic changes in the industry, significant technological changes in both generation and transmission have occurred since 1935. Through the 1960s, bigger was cheaper in the generation sector and the industry was able to capitalize on economies of scale to produce power at lower per-unit costs from larger and larger plants.[22] As a result, large utility companies that could finance and manage construction projects of larger scale had a price advantage over smaller utility companies and customers who might otherwise have considered building their own generating units. Scale economies encouraged power generation by large vertically-integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however, additional economies of scale in generation were no longer being achieved.[23] A significant factor was that larger generation units were found to need relatively greater maintenance and experience longer downtimes.[24] The electric industry faced the situation ''where the price of each incremental unit of electric power exceeded the average cost.'' [25] Bigger was no longer better.

Further dictating against larger generation units were advances in technologies that allowed scale economies to be exploited by smaller size units, thereby allowing smaller new plants to be brought on line at costs below those of the large plants of the 1970s and earlier. Such new technologies include combined cycle units and conventional steam units that use circulating fluidized bed boilers.[26]

The combined cycle generating plants generally use natural gas as their primary fuel. This technology has been made possible by the development of more efficient gas turbines, shorter construction lead times, lower capital costs, increased reliability, and relatively minimal environmental impacts.[27] Similarly, the circulating fluidized bed combustion boilers, fueled by coal and other conventional fuels, provide a more efficient and less polluting resource.

Today, ''the optimum size (of generation plants) has shifted from (more than 500 MW) (10-year lead time) to smaller units (one-year lead time) (in the 50- to 150–MW range).'' [28] Indeed, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost ranging from 5 cents per kWh to less than 3 cents per kWh.[29] This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.[30] Significant changes have also occurred in the transmission sector of the industry. Technological advances in transmission have made possible the economic transmission of electric power over long distances at higher voltages.[31] This has

[15] *See* Bernard S. Black & Richard J. Pierce, Jr., The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry, 93 Col. L. Rev. 1339, 1346 (1993) (''Actual costs of nuclear power plants vastly exceeded estimates, sometimes by as much as 1000%.'').

[16] *See* Phillips, *supra* at 13. Fossil fuel-fired plants became subject to increased regulation as a result of the Clean Air Act of 1970, and its 1977 amendments. 42 U.S.C. 7401–7642. In 1971, nuclear plant licensing became subject to the environmental impact statement requirements of the National Environmental Policy Act of 1969. 42 U.S.C. 4332. Following the 1979 accident at the Three Mile Island nuclear plant, nuclear plants also became subject to additional safety regulations, resulting in higher costs. *See* Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970–1991* (March 1993) 35. Between 1976 and 1980, most states and many localities instituted laws governing power plant siting.

[17] Based on retail prices reported in Energy Information Administration (EIA), Monthly Energy Review, January 1995, Table 9.9 (Prices adjusted for inflation using the GDP Deflator (1987 = 100)).

[18] *Id.*

[19] *See* Black & Pierce, *supra* at 1346 (These writeoffs were ''about 17% of the book value of total 1992 utility investment.'').

[20] *Id.*

[21] *Id.* (''The high perceived risk of future disallowances reversed utilities' incentives to overinvest, and made utilities extremely reluctant to build new power plants.'').

[22] *See* Preston Michie, Billing Credits for Conservation, Renewable, and Other Electric Power Resources: an Alternative to Marginal-Cost-Based Power Rates in the Pacific Northwest, 13 Environmental Law 963, 964–65 (1983).

[23] *Id.* at 965.

[24] Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970–1991* (March 1993) 37 (''As larger units were constructed, however, utilities discovered that downtime was as much as 5 times greater for units larger than 600 megawatts than for units in the 100-megawatt range.'')

[25] *Id.; see also* George A. Perrault, Downsizing Generation: Utility Plans for the 1990s, Pub. Util. Fort. 15–16 (Sept. 27, 1990) (''The large base-load generating units that form the backbone of utility systems are almost totally absent from capacity plans for the 1990s.'').

[26] ''From 1982 through 1991, the average capacity of fluidized-bed units increased rapidly to 72 megawatts for 4 units in 1991. The average capacity for the 19 units planned to begin operating in 1992 through 1995 increases to 83 megawatts.'' Energy Information Administration, *The Changing Structure of the Electric Power Industry 1970–1991* (March 1993) 38.

[27] *See* Charles E. Bayless, Less is More: Why Gas Turbines Will Transform Electric Utilities, Pub. Util. Fort. (Dec. 1, 1994) 21.

[28] *Id.* at 24. *See also* Wallace E. Brand, Is Bigger Better? Market Power in Bulk Power Supply: From FDR to NOPR, Pub. Util. Fort. (Feb. 15, 1996) 23 at 25 (while the optimal baseload unit size is about 500 MW for coal-fired steam turbines, the optimal size for gas fired combined-cycle units is about 150 to 200 MW).

[29] FERC staff calculations based in part on combined-cycle plant cost data reported in 1994 FERC Form No. 1 for a sample of units placed in service during 1990–94. Costs vary with regional fuel and construction costs, among other reasons.

[30] Coal and Nuclear plant cost data reported in 1994 FERC Form No. 1 and the EIA report, *Electric Plant Cost and Power Production Expenses 1991*, 1993 DOE/EIA–0455(91), for plants placed in service during 1986–94; *see also* The 1994 Electric Executives' Forum, Bakke (President and CEO of the AES Corporation), Pub. Util. Fort. (June 1, 1994) 45 (''New generation can be built at about 3 cents per kilowatt-hour (U.S. average). Old generation costs about twice that * * *'').

[31] *See* Black & Pierce, *supra* at 1345 (In the late 1960s and 1970s, improved transmission efficiency and development of regional transmission networks ''made it possible to build power plants up to 1000 miles from power users.'').

made it technically feasible for utilities with lower cost generation sources to reach previously isolated systems where customers had been captive to higher cost generation. In addition, the nature and magnitude of coordination transactions [32] have changed dramatically since enactment of the FPA, allowing increased coordinated operations and reduced reserve margins. Substantial amounts of electricity now move between regions, as well as between utilities in the same region. Physically isolated systems have become a thing of the past.

C. The Public Utility Regulatory Policies Act and the Growth of Competition

In enacting PURPA,[33] Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates and harming the economy as a whole.[34] To lessen dependence on expensive foreign oil, avoid repetition of the 1977 natural gas shortage, and control consumer costs, Congress sought to encourage electric utilities to conserve oil and natural gas.[35] In particular, Congress sanctioned the development of alternative generation sources designated as ''qualifying facilities'' (QFs) as a means of reducing the demand for traditional fossil fuels.[36] PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.[37]

PURPA specifically set forth limitations on who, and what, could qualify as QFs. In addition to technological and size criteria, PURPA set limits on who could own QFs.[38] Notwithstanding these limitations, QFs proliferated. In 1989, there were 576 QF facilities. By 1993, there were more than 1,200 such facilities.[39] For the same time period, installed QF capacity increased from 27,429 megawatts to 47,774 megawatts.[40] The rapid expansion and performance of the QF industry demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power.

During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. QFs were limited to cogenerators and small power producers.[41]

However, other non-traditional power producers who could not meet the QF criteria began to build new capacity to compete in bulk power markets, without such PURPA benefits as the mandatory purchase requirements. These producers, known as independent power producers (IPPs), were predominantly single-asset generation companies that did not own any transmission or distribution facilities. While traditional utilities were generally reluctant at that time to invest in new generating facilities under cost of service regulation, utilities increasingly became interested in participating in this new generation sector. They organized affiliated power producers (APPs), with assets not included in utility rate base, and sought to sell power in their own service territories and the territories of other utilities. At the same time, power marketers arose. These entities—owning no transmission or generation—buy and sell power.[42]

There were two major impediments to the development of IPPs and APPs. First, the ownership restrictions of the Public Utility Holding Company Act (PUHCA) [43] severely inhibited these new entities from entering the generation business.[44] Second, these entities needed transmission service in order to compete in electricity markets.

While the Commission had no authority to remove PUHCA restrictions,[45] it encouraged the development of IPPs and APPs, as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis and by encouraging more widely available transmission access. From 1989 through 1993, facilities owned by IPPs and other non-traditional generators (other than QFs) increased from 249 to 634 and their installed capacity increased from 9,216 megawatts to 13,004 megawatts.[46] Indeed, ''[i]n 1992, for the first time, generating capacity added by independent producers exceeded capacity added by utilities.'' [47]

Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs, which entail procedural delays in achieving tariff approvals and changes.

In approving these market-based rates, the Commission required, *inter alia,* that the seller and any of its affiliates lack market power or mitigate any market

[32] Coordination transactions are voluntary sales or exchanges of specialized electricity services that allow buyers to realize cost savings or reliability gains that are not attainable if they rely solely on their own resources. For sellers, these transactions provide opportunities to earn additional revenue, and to lower customer rates, from capacity that is temporarily excess to native load capacity requirements.

[33] Pub. L. No. 95–617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[34] See generally FERC v. Mississippi, 456 U.S. 742, 745–46 (1982).

[35] The Power Plant and Industrial Fuel Use Act of 1978. Pub. L. No. 95–617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

[36] QFs include certain cogenerators and small power producers. PURPA also added sections 210, 211, and 212 to the FPA, providing the Commission with authority to approve applications for interconnections and, in limited circumstances, wheeling. However, under section 211, as enacted in PURPA, the Commission could approve an application for wheeling only if it found, *inter alia,* that the order ''would reasonably preserve existing competitive relationships.'' Because of this and other limitations in sections 211 and 212 as originally enacted, the provision was virtually ineffective. Only one section 211 order was ever issued pursuant to the original provision, and it was pursuant to a settlement. *See* Public Service Company of Oklahoma, 38 FERC ¶ 61,050 (1987). As discussed *infra,* section 211 was subsequently revised by the Energy Policy Act of 1992.

[37] 456 U.S. at 750. Congress recognized that encouragement was needed in part because utilities had been reluctant to purchase electric power from, and sell power to, nonutility generators. *Id.* at 750–51.

[38] For example, PURPA provided that a cogeneration facility or small power production facility could not be owned by a person primarily engaged in the generation or sale of electric power (other than from cogeneration or small power production facilities). *See* 16 U.S.C.

[39] Energy Information Administration, *Electric Power Annual 1993* (December 1994) 124 (Table 77).

[40] *Id*. EIA data for 1989 through 1991 was for facilities of 5 megawatts or more and for 1992 and 1993 was for facilities of 1 megawatt or more. A comparison with Table 74 on page 121 for the years 1992 and 1993 reveals that this mixing of data bases is likely of minimal effect.

[41] Generally, the law has imposed an 80 MW cap on small power producers. A limited exception enacted in 1990 permitted small power facilities that could exceed 80 MW and still qualify as QFs under PURPA. This exception was limited to certain solar, wind, waste, and geothermal small power production facilities and only covered applications for certification of facilities as qualifying small power production facilities that were submitted no later than December 31, 1994 and for which construction commences no later than December 31, 1999. *See* Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990, Pub. L. No. 101–575, 104 Stat. 2834 (1990), *amended,* Pub. L. No. 102–46, 105 Stat. 249 (1991).

[42] The first power marketer in the electric industry was Citizens Energy Corporation. *See* Citizens Energy Corporation, 35 FERC ¶ 61,198 (1986). Power marketers take title to electric energy. Power brokers, on the other hand, do not take title and are limited to a matchmaking role.

[43] 15 U.S.C. 79 *et seq.*

[44] As discussed *infra,* Congress eventually provided a means to avoid the PUHCA restrictions by creating exempt wholesale generators (EWGs) in the Energy Policy Act.

[45] The industry was successful to some extent in developing ownership structures that permitted such investment. *See, e.g.,* Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 at 62,240 and n.20 (1990).

[46] Energy Information Administration, *Electric Power Annual 1993* (December 1994) 124 (Table 77).

[47] Black & Pierce, *supra* at 1349 n.25.

power that they may have possessed.[48] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing.[49] As we have previously explained:

> The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive *ownership* of the facilities. However, market power also may be gained without ownership. Contracts can confer the same rights of control. Entities with contractual control over transmission facilities can withhold supply and extract monopoly prices just as effectively as those who control facilities through ownership.[50]

As entry into wholesale power generation markets increased, the ability of customers to gain access to the transmission services necessary to reach competing suppliers became increasingly important.[51] In addition, beginning in the late 1980s, in order to mitigate their market power to meet Commission conditions, public utilities seeking Commission approval of mergers or consolidations under section 203 of the FPA or Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA, filed ''open access'' transmission tariffs of general applicability.[52] The Commission applied its market rate analysis to IOUs, as well as IPPs, APPs, and marketers, and allowed IOUs to sell at market-based rates only if they opened their transmission systems to competitors.[53] The Commission also approved proposed mergers on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing ''open access'' tariffs. These early ''open access'' tariffs required only that the companies provide point-to-point transmission services, which is a much narrower requirement than that being imposed in this Rule and did not require transmission owners to provide to others the same quality of service that they themselves enjoyed.

Following PURPA, the economic and technological changes in the transmission and generation sectors helped give impetus to the many new entrants in the generating markets who could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, it became increasingly clear that the potential consumer benefits that could be derived from these technological advances could be realized only if more efficient generating plants could obtain access to the regional transmission grids. Because many traditional vertically integrated utilities still did not provide open access to third parties and still favored their own generation if and when they provided transmission access to third parties, barriers continued to exist to cheaper, more efficient generation sources.

D. The Energy Policy Act

In response to the competitive developments following PURPA, and the fact that PUHCA and lack of transmission access remained major barriers to new generators, Congress enacted Title VII of the Energy Policy Act of 1992 (Energy Policy Act).[54] A goal of the Energy Policy Act was to promote greater competition in bulk power markets by encouraging new generation entrants, known as exempt wholesale generators (EWGs), and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services.[55]

An EWG is defined as

> Any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly through one or more affiliates as defined in [PUHCA] section 2(a)(11)(B), and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale.[56]

If the Commission, upon an application, determines that a person is an EWG, that person will be exempt from PUHCA.[57] This provision removed a significant impediment to the development of IPPs and APPs by allowing them to develop projects as EWGs free from the strictures of PUHCA or the QF PURPA limitations.

While sections 211 and 212, as enacted by PURPA, were intended to provide greater access to the transmission grid, the limitations placed on these sections made them unusable in virtually all circumstances.[58] However, as amended by the Energy Policy Act, these sections now give the Commission broader authority to order transmitting utilities to provide wholesale transmission services, upon application, to any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale.

The Energy Policy Act also added section 213 to the FPA. Section 213(a) requires a transmitting utility that does not agree to provide wholesale transmission service in accordance with a good faith request to provide a written explanation of its proposed rates, terms, and conditions and its analysis of any

[48] *See, e.g.,* Ocean State Power, 44 FERC ¶ 61,261 (1988); Commonwealth Atlantic Limited Partnership, 51 FERC ¶ 61,368 (1990); Citizens Power & Light Company, 48 FERC ¶ 61,210 (1989); Orange and Rockland Utilities, Inc., 42 FERC ¶ 61,012 (1988); Doswell Limited Partnership, 50 FERC ¶ 61,251 (1990) (*Doswel*); and Dartmouth Power Associates Limited Partnership, 53 FERC ¶ 61,117 (1990).

[49] *See, e.g., Doswell,* 50 FERC at 61,757.

[50] Citizens Power & Light Corporation, 48 FERC ¶ 61,210 at 61,777 (1989) (emphasis in original); *see also* Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corporation, 45 FERC ¶ 61,095 at 61,287–89 (1988), *order on reh'g,* 47 FERC ¶ 61,209, *order on reh'g,* 48 FERC ¶ 61,035 (1989), *remanded in part sub nom.* Environmental Action, Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991), *order on remand,* 57 FERC ¶ 61,363 (1991).

[51] In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the Supreme Court's decision in *Otter Tail Power Company v. United States,* 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with federal power marketing agencies. *See, e.g.,* Consumers Power Company, 6 NRC 887, 1036–44 (1977) and The Toledo Edison Company and Cleveland Electric Illuminating Company, 10 NRC 265, 327–34 (1979). *See* Florida Municipal Power Agency v. Florida Power and Light Company, 839 F. Supp. 1563 (M.D. Fla. 1993). *See also* Electricity Transmission: Realities, Theory and Policy Alternatives, The Transmission Task Force Report to the Commission, October 1989, 197.

[52] *See, e.g.,* Public Service Company of Colorado, 59 FERC ¶ 61,311 (1992), *reh'g denied,* 62 FERC ¶ 61,013 (1993); Utah Power & Light Company, *et al.,* Opinion No. 318, 45 FERC ¶ 61,095 (1988), *order on reh'g,* Opinion No. 318–A, 47 FERC ¶ 61,209 (1989), *order on reh'g,* Opinion No. 318–B, 48 FERC ¶ 61,035 (1989), *aff'd in relevant part sub nom.* Environmental Action Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991); Northeast Utilities Service Company (Public Service Company of New Hampshire), Opinion No. 364–A, 58 FERC ¶ 61,070, *reh'g denied,* Opinion No. 364–B, 59 FERC ¶ 61,042, *order granting motion to vacate and dismissing request for rehearing,* 59 FERC ¶ 61,089 (1992), *affirmed in relevant part sub nom.* Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993).

[53] *See, e.g.,* Public Service of Indiana, Inc., 51 FERC ¶ 61,367 (1990), *reh'g denied,* 52 FERC ¶ 61,260 (1990), *appeal dismissed sub nom.* Northern Indiana Public Service Company v. FERC, 954 F.2d 736 (D.C.Cir. 1992).

[54] Pub. L. No. 102–486, 106 Stat. 2776 (1992), codified at, among other places, 15 U.S.C. 79z–5a and 16 U.S.C. 796 (22–25), 824j–l.

[55] *See* El Paso Electric Company and Central and South West Services Inc., 68 FERC ¶ 61,181 at 61,914 (1994) *(CSW); see also* Paul Kemezis, FERC's Competitive Muscle: The Comparability Standard, Electrical World 45 (Jan. 1995) (''In EPAct, Congress made it clear that the electric-power industry was to move toward a fully competitive market system, but left most of the implementation to FERC.'').

[56] 15 U.S.C. 79z–5a.

[57] 15 U.S.C. 79z–5a(e).

[58] *See supra* note 36.

physical or other constraints.[59] Section 213(b) required the Commission to enact a rule requiring transmitting utilities to submit annual information concerning potentially available transmission capacity and known constraints.[60]

E. The Present Competitive Environment

Following the Energy Policy Act, the Commission established rules: (1) For certain generators to obtain EWG status and thus an exemption from PUHCA;[61] and (2) that required transmission information availability. The Commission also pursued a number of initiatives aimed at fostering the development of more competitive bulk power markets, including aggressive implementation of section 211, a new look at undue discrimination under the FPA, easing of market entry for sellers of generation from new facilities, and initiation of a number of industry-wide reforms. As stated by the Commission, in recognition of the Congressional goal in the Energy Policy Act of creating competitive bulk power markets:

> Our goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa.[62]

1. Use of Sections 211 and 212 to Obtain Transmission Access

The Commission has aggressively implemented sections 211 and 212 of the FPA, as amended by the Energy Policy Act, in order to promote competitive markets.[63] When wheeling requests under sections 211 and 212 have been made, the Commission has required wheeling in almost all of the requests it has processed. To date, the Commission has issued orders (proposed or final) requiring wheeling in 12 of the 14 cases it has acted on.[64]

As a general matter, section 211 has permitted some inroads to be made by customers in obtaining transmission service from public utilities that historically have declined to provide access to their systems, or have offered service only on a discriminatory basis. Under section 211, the Commission has granted requests for the broader type of service that most utilities historically have refused to provide—network service. Although transmission owners have provided limited amounts of unbundled point-to-point transmission service, third-party customers have not been able to obtain the flexibility of service that transmission owners enjoy.

In *Florida Municipal*, a section 211 case, the Commission ordered ''network,'' rather than the narrower ''point-to-point,'' service.[65] Network service permits the applicant to fully integrate load and resources on an instantaneous basis in a manner similar to the transmission owner's integration of its own load and resources. At the same time, the Commission made the generic finding that the availability of transmission service will enhance competition in the market for power supplies and lead to lower costs for consumers. The Commission explained that as long as the transmitting utility is fully and fairly compensated and there is no unreasonable impairment of reliability, transmission service is in the public interest.[66]

As discussed *infra*, based on the mounting competitive pressures in the industry and rapidly evolving markets, we have concluded that section 211 alone is not enough to eliminate undue discrimination. The comments received on the proposed rules, discussed in detail *infra*, confirm this conclusion. The significant time delays involved in filing an individual service request for bilateral service under section 211 place the customer at a severe disadvantage compared to the transmission owner and can result in discriminatory treatment in the use of the transmission system. It is an inadequate procedural substitute for readily available service under a filed non-discriminatory open access tariff. As the Commission noted in *Hermiston Generating Company*, ''[t]he ability to spend time and resources litigating the rates, terms and conditions of transmission access is not equivalent to an enforceable voluntary offer to provide comparable service under known rates, terms and conditions.''[67]

2. Commission's Comparability Standard

In the Spring of 1994, the Commission began to address the problem of the disparity in transmission service that utilities provided to third parties in comparison to their own uses of the transmission system. In the seminal case in this area, *American Electric Power Service Corporation* (*AEP*), the company voluntarily proposed a tariff of general applicability that would offer firm, point-to-point transmission service for a minimum of one month.[68] The Commission accepted the proposed transmission tariff for filing and suspended its effectiveness for one day, subject to refund.[69] Rehearing requests challenged the Commission's summary approval of the restriction of service to point-to-point as being discriminatory and anticompetitive.[70] The rehearing

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[59] *See* Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Sections 211(a) and 213(a) of the Federal Power Act, as Amended and Added by the Energy Policy Act of 1992, 58 FR 38964 (July 21, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,975 (1993) (Policy Statement Regarding Good Faith Requests for Transmission Services).

[60] *See* New Reporting Requirements Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities Under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC–714, 58 FR 52420 (October 8, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,980 (Order No. 558), *reh'g denied*, Order No. 558–A, 65 FERC ¶ 61,324 (1993), *regulations modified*, 59 FR 15333 (April 1, 1994), FERC Stats. & Regs., Regulations Preambles ¶ 30,993.

[61] *See* Order No. 550, Filing Requirements and Ministerial Procedures for Persons Seeking Exempt Wholesale Generator Status, 58 FR 8897 (February 18, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,964, *order on reh'g*, Order No. 550–A, 58 FR 21250 (April 20, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,969 (1993). As recognized by Congress and the Commission, availability of transmission information is critical in developing competitive markets. *See supra* notes 59 and 60. This opened the ''black box'' of information that previously was available only to transmission owners.

[62] *See* Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), FERC Stats. & Regs., Proposed Regulations ¶ 32,507 at 32,866 (Stranded Cost NOPR); American Electric Power Service Corporation, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994).

[63] 16 U.S.C.A. 824j–824k (West 1985 and Supp. 1994).

[64] *See, e.g.*, final orders issued in City of Bedford, 68 FERC ¶ 61,003 (1994), *reh'g denied*, 73 FERC ¶ 61,322 (1995); Florida Municipal Power Agency v. Florida Power & Light Company, 67 FERC ¶ 61,167 (1994), *order on reh'g*, 74 FERC ¶ 61,006 (1996); Minnesota Municipal Power Agency, 68 FERC ¶ 61,060 (1994); and Tex-La Electric Cooperative of Texas, 69 FERC ¶ 61,269 (1994); *see also* Appendix A.

[65] *See* Florida Municipal Power Agency v. Florida Power & Light Company, 65 FERC ¶ 61,125, *reh'g dismissed*, 65 FERC ¶ 61,372 (1993), *final order*, 67 FERC ¶ 61,167 (1994), *order on reh'g*, 74 FERC ¶ 61,006 (1996). The Commission has ''characterized point-to-point service as involving designated points of entry into and exit from the transmitting utility's system, with a designated amount of transfer capability at each point.'' El Paso Electric Company v. Southwestern Public Service Company, 68 FERC ¶ 61,182 at 61,926 n.9 (1994) (*citing* Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,768 (1993), *reh'g dismissed*, 68 FERC ¶ 61,399 (1994)). Network service allows more flexibility by allowing a transmission customer to use the entire transmission network to provide generation service for specified resources and specified loads without having to pay multiple charges for each resource-load pairing.

[66] *Florida Municipal*, 67 FERC at 61,477.

[67] 69 FERC ¶ 61,035 at 61,165 (1994), *reh'g denied*, 72 FERC ¶ 61,071 (1995); *see also* Southwest Regional Transmission Association, 69 FERC ¶ 61,100 at 61,398 (1994), *order on compliance filing*, 73 FERC ¶ 61,147 (1995) (*SWRTA*).

[68] 64 FERC ¶ 61,279 (1993), *reh'g granted*, 67 FERC ¶ 61,168, *clarified*, 67 FERC ¶ 61,317 (1994).

[69] The Commission explained that AEP could limit the service it was offering because it was ''providing the service voluntarily under a tariff of general applicability.'' 64 FERC at 62,978.

[70] *AEP*, 67 FERC at 61,489.

requests argued that the tariff should be expanded to include network services such as those used by the transmission owner. On rehearing, the Commission announced a new standard for evaluating claims of undue discrimination.

The Commission found that a voluntarily offered, new open access transmission tariff that did not provide for services comparable to those that the transmission owner provided itself was unduly discriminatory and anticompetitive.[71] In reaching that conclusion, the Commission broadened its undue discrimination analysis (which traditionally had focused on the rates, terms, and conditions faced by similarly situated third-party customers) to include a focus on the rates, terms, and conditions of a utility's own uses of the transmission system:

(A)n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system.[72]

Refocusing the analysis was necessitated by the changing conditions in the electric utility industry, including the emergence of non-traditional suppliers and greater competition in bulk power markets. Because a transmission provider may use its system in different ways (*e.g.*, to integrate load and resources when serving retail native load, to make off-system sales or purchases, or to serve wholesale requirements customers), the Commission set for hearing the factual issues associated with identifying those uses, as well as any potential impediments or consequences to providing comparable services to third parties.[73]

After *AEP*, the Commission applied this comparability standard to a proposed open access transmission tariff that was filed by Kansas City Power & Light Company (KCP&L) in support of a proposal to sell generation at market-based rates.[74] The Commission explained that, in light of *AEP*, the utility's proposed open access transmission tariff (which provided only for point-to-point service) did not adequately mitigate its transmission market power so as to justify allowing the requested market-based rates. KCP&L could charge market-based rates for sales only if it modified its proposed transmission tariff to reflect the *AEP* comparability standard.

Since then, the Commission has required comparable service in a variety of contexts, and has set for hearing the factual issues associated with comparable service. For example, the Commission found that market power can be adequately mitigated only if a merged company offers transmission services in accordance with the *AEP* comparability standard.[75] The Commission further held that, even if a merger does not result in an increase in market power, the merger would not be consistent with the public interest under section 203 of the FPA unless the merged company offers comparable transmission services, as defined in *AEP*.[76] The Commission therefore announced a transmission comparability requirement for all new mergers:

Given the transition of the electric utility industry as a whole, we conclude that, absent other compelling public interest considerations, coordination in the public interest can best be secured only if merging utilities offer comparable transmission services.[77]

In *Heartland Energy Services, Inc.*,[78] the Commission applied its comparability standard to an affiliated electric power marketer seeking blanket authorization to sell electricity at market-based rates. The Commission explained that

For all future cases involving blanket approval of market-based rates an offer of comparable transmission services will be required before the Commission will be able to find that transmission market power has been adequately mitigated. In the context of an affiliated power marketer, this means that all of its affiliated utilities must have a comparable transmission tariff on file.[79]

The Commission also denied a request by a company affiliated with a transmission-owning utility seeking permission to sell power at market-based rates to a particular customer. The denial was without prejudice to refiling such a request in a new section 205 proceeding, but only after the affiliated transmission-owning utility filed a comparable transmission service tariff.[80] The Commission added that it

Will require comparability in any situation in which a seller seeking market-based rates is affiliated with an owner or controller of transmission facilities.[81]

The Commission has also stated that ''it will henceforth apply the transmission comparability standard announced in the *AEP* case to all transmitting utility members of an RTG.'' [82]

The Commission further declared that comparable services must be provided through ''open access'' tariffs rather than only on a contract-by-contract basis:

(T)ariffs are essential to the provision of comparable services. Tariffs set out the services that are available and the terms and conditions under which those services will be made available * * *. (In contrast), a negotiation process creates uncertainty and imposes on customers delay and other transaction costs that the transmitting utility members of an RTG do not incur when using the transmission for their own benefit. Moreover, the ability to execute separate transmission agreements with different but similarly situated customers is the ability to unduly discriminate among them. A tariff ensures against such discrimination in the RTG.[83]

[71] With respect to anticompetitive effects, the Commission explained that it has ''adhered to the Supreme Court's determination that the Commission's 'important and broad regulatory power * * * carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to sections 202 and 203, and under like directives contained in sections 205, 206 and 207.' Gulf States Utilities Company v. FPC, 411 U.S. 747, 758–59 (1972).'' *Id.* at 61,490 (footnote omitted). The Commission reaffirmed that it would examine how best to fulfill this responsibility, as well as its responsibility to prevent undue discrimination, in light of the changing conditions in the electric utility industry. *Id.*

[72] *Id.* at 61,490.

[73] *Id.* at 61,490–91.

[74] *See* Kansas City Power & Light Company, 67 FERC ¶ 61,183 (1994), *reh'g pending.*

[75] *E.g., CSW, supra,* 68 FERC at 61,914.

[76] *Id.*

[77] *Id.* at 61,915 (footnote omitted).

[78] 68 FERC ¶ 61,223 (1994).

[79] Id. at 62,060. In InterCoast Power Marketing Company, 68 FERC ¶ 61,248, *clarified*, 68 FERC ¶ 61,324 (1994), the Commission rejected an affiliated marketer's proposal to sell at market rates without its affiliate utility offering comparable transmission services. The Commission stated that the only way to ensure that InterCoast does not have transmission market power is to require its affiliated public utility to offer comparable transmission services. *See also* LG&E Power Marketing Inc., 68 FERC ¶ 61,247 at 62,120–21 (1994). The Commission added that this is consistent with encouraging competitive bulk power markets as envisioned by the Energy Policy Act of 1992. *Id.* at 62,132.

[80] *See* Hermiston Generating Company, 69 FERC ¶ 61,035 at 61,164 (1994), *reh'g pending.* The Commission subsequently accepted the rates on a cost basis. *See* Letter Order dated November 10, 1994.

[81] *Id.* at 61,165.

[82] *See SWRTA*, 69 FERC at 61,397; *see also* PacifiCorp, the California Municipal Utilities Association, and the Independent Energy Producers (on behalf of Western Regional Transmission Association), 69 FERC ¶ 61,099, *order on reh'g*, 69 FERC ¶ 61,352 (1994), *order on compliance filing*, 71 FERC ¶ 61,158 (1995) (*WRTA*). An RTG is a regional transmission group. It is defined as ''a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and inter-regional.'' Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (August 5, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,976 at 30,870 n. 4 (RTG Policy Statement).

[83] *SWRTA*, 69 FERC at 61,398.

Thus, the Commission required the RTGs to amend their bylaws to commit all transmitting utility members to offer comparable transmission services to other RTG members pursuant to a transmission tariff or tariffs.

As discussed below, since the *AEP* comparability standard was announced, the Commission has set for hearing 44 open access tariffs to determine what constitutes comparable service. This number includes tariffs filed subsequent to the Open Access NOPR. All tariffs have now been made subject to the outcome of the Final Rule.

3. Lack of Market Power in New Generation

In 1994 in the *KCP&L* case, discussed in the prior section, the Commission continued to recognize that transmission remains a natural monopoly. However, it found that, in light of the industry and statutory changes that now allow ease of market entry, no wholesale seller of generation has market power in generation from *new* facilities.[84] In particular, the Commission explained that it had previously noted in *Entergy Services, Inc.* that

> There was significant evidence that non-traditional power project developers, including qualifying facilities and independent power projects, are becoming viable competitors in long-run markets.[85]

The Commission further explained that since *Entergy*, Congress had enacted the Energy Policy Act, which had lowered barriers to the entry of new suppliers by creating a new class of power suppliers—EWGs—that are exempt from the provisions of PUHCA.[86] The Commission concluded that, in considering market-based rate proposals for generation sales, it need only focus on market power in transmission, generation market power in short-run markets, and other barriers to entry.[87]

4. Further Commission Action Addressing a More Competitive Electric Industry

To address the fact that the electric industry is becoming more competitive, and to remove barriers that might inhibit a more competitive industry, the Commission has initiated a number of proceedings: (1) Stranded Cost NOPR,[88] (2) Transmission Pricing Policy Statement,[89] (3) Pooling Notice of Inquiry,[90] (4) Regional Transmission Group (RTG) Policy Statement,[91] and (5) Notice of Inquiry on Merger Policy.[92]

In the Stranded Cost NOPR the Commission recognized that the trend toward greater transmission access and the transition to a fully competitive bulk power market could cause some utilities to incur stranded costs as wholesale requirements customers (or retail customers) use their supplier's transmission to purchase power elsewhere. As the Commission noted, a utility may have built facilities or entered into long-term fuel or purchased power supply contracts with the reasonable expectation that its customers would renew their contracts and would pay their share of long-term investments and other incurred costs. If the customer obtains another power supplier, the utility may have stranded costs. If the utility cannot locate an alternative buyer or somehow mitigate the stranded costs, the Commission explained that ''the costs must be recovered from either the departing customer or the remaining customers or borne by the utility's shareholders.'' [93] Accordingly, the Commission proposed to establish provisions concerning the recovery of wholesale and retail stranded costs by public utilities and transmitting utilities.

In the Transmission Pricing Policy Statement, the Commission announced a new policy providing greater flexibility in the pricing of transmission services provided by public utilities and transmitting utilities. The Commission traditionally had allowed only postage-stamp, contract-path pricing.[94] Under the new policy, we will permit a variety of proposals, including distance sensitive and flow-based pricing, which may be more suitable for competitive wholesale power markets.[95] The Commission explained that this ''(g)reater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992.'' [96] However, the Commission explained that any new transmission pricing proposal must meet the Commission's *AEP* comparability standard. The Commission further explained that comparability of service applies to price as well as to terms and conditions.[97]

The Commission issued the Pooling Notice of Inquiry to receive comments on traditional power pools and on alternative power pooling institutions that are being explored in today's more competitive environment. The Commission expressed concern that

> (G)iven the ongoing changes in the competitive environment of the electric utility industry—in particular, the potential for substantially increased access to transmission—we must consider whether we are appropriately balancing our dual objectives of promoting coordination and competition.[98]

Accordingly, the Commission explained that it wished to look at alternative power pooling institutions and to re-examine the role of more traditional power pools in today's environment of increased competition. In particular the Commission expressed its intent to ensure that its policies ''are consistent with the development of a competitive bulk power market.'' [99]

In the RTG Policy Statement, the Commission announced a policy encouraging the development of RTGs. The Commission explained that a primary purpose of RTGs is to facilitate transmission access for potential users and voluntarily resolve disputes over such service. The Commission has approved the formation of three

[84] *KCP&L*, 67 FERC ¶ 61,183 (1994).

[85] *Id.* at 61,557 (citing Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,756 and nn. 63 and 65 (*Entergy*)).

[86] *Id.* The Commission added that ''after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets.'' *Id.*

[87] *Id.*

[88] FERC Stats. & Regs. ¶ 32,507 (1994).

[89] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55031 (November 3, 1994), FERC Stats. & Regs., Regulations Preambles ¶ 31,005 (Transmission Pricing Policy Statement).

[90] Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, 59 FR 54851 (October 26, 1994), FERC Stats. & Regs., Notices ¶ 35,529 (1995) (Pooling Notice of Inquiry).

[91] FERC Stats. & Regs. ¶ 30,976 (RTG Policy Statement).

[92] FERC Stats. & Regs. ¶ 35,531 (1996).

[93] FERC Stats. & Regs. ¶ 32,507 at 32,864.

[94] Most transmission contracts set a single price for energy flow over a utility's transmission system. This single-price policy is called ''postage stamp'' pricing because the rate does not depend on how far the power moves within a company's transmission system. If power flows through several companies, traditional industry practice is to specify that power flows along a ''contract path'' consisting of the transmission-owning utilities between the ultimate receipt and delivery points. *See* Indiana Michigan Power Company, 64 FERC ¶ 61,184 at 62,545 (1993).

[95] Unlike with postage stamp pricing, with distance-sensitive pricing the cost of moving power through a company depends on how far the power moves within the company. In contrast to contract path pricing, flow-based pricing establishes a price based on the costs of the various parallel paths actually used when the power flows. Because flow-based pricing can account for all parallel paths used by the transaction, all transmission owners with facilities on any of the parallel paths could be compensated for the transaction.

[96] FERC Stats. & Regs. ¶ 31,005 at 31,136.

[97] *Id.* at 31,142.

[98] FERC Stats. & Regs. ¶ 35,529 at 35,715.

[99] *Id.* at 35,714. As explained below, the Commission held technical conferences on issues surrounding power pools and competition.

RTGs.[100] One of the conditions is that each RTG member must offer comparable transmission services by tariff to other RTG members.

In the merger NOI, the Commission indicated that it will review whether its criteria and policy for evaluating mergers need to be modified in light of the changing circumstances occurring in the electric industry.

In addition to the Commission's actions, a number of states have initiated proceedings concerning retail wheeling or proposed legislation for retail wheeling, that is, for ultimate consumers to choose their supplier of power, or other restructuring proposals.[101]

5. Events Since Issuance of Open Access NOPR

Since issuance of the Open Access NOPR, public utilities have filed, in some form or another, 47 open access tariffs. In acting on those filings, the Commission has made all of the non-rate terms and conditions of those proposed tariffs subject to the outcome of this Final Rule.[102]

Over the last year, the Commission also has received and analyzed more than 20,000 pages of comments that were received from over 400 commenters, as well as additional information provided by industry participants at a number of Commission-initiated technical conferences.[103] Those technical conferences addressed several issues—ancillary services, pro forma tariffs, power pools, and ISOs—and provided significant input to the Commission's formulation of this Final Rule.

F. Need for Reform

The many changes discussed above have converged to create a situation in which new generating capacity can be built and operated at prices substantially lower than many utilities' embedded costs of generation. As discussed above, new generation facilities can produce power on the grid at a cost of less than 3 cents per kWh to 5 cents per kWh, yet the costs for large plants constructed and installed over the last decade were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.

Non-traditional generators are taking advantage of this opportunity to compete. Indeed, the non-traditional generators' share of total U.S. electricity generation increased from 4 percent in 1985 to 10 percent in 1993.[104] Much of this increased share of generation is the result of competitive bidding for new generation resources that has occurred in 37 states. Since 1984, almost 4,000 projects, representing over 400,000 MW, have been offered in response to requests. Over 350 projects have been selected to supply 20,000 MW, and, of these, 126 are now online producing almost 7,800 MW of power.[105]

In addition, the cost of utility-generated electricity differs widely across the major regions of the United States. Average utility rates range from 3 to 5 cents in the Northwest to 9 to 11 cents in California. Electricity consumers are demanding access to lower cost supplies available in other regions of the United States, and access to the newer, lower cost generation resources. Therefore, it is important that the non-traditional generators of cheaper power be able to gain access to the transmission grid on a non-discriminatory open access basis.

The Commission's goal is to ensure that customers have the benefits of competitively priced generation. However, we must do so without abandoning our traditional obligation to ensure that utilities have a fair opportunity to recover prudently incurred costs and that they maintain power supply reliability. As well, the benefits of competition should not come at the expense of other customers. The Commission believes that requiring utilities to provide non-discriminatory open access transmission tariffs, while simultaneously resolving the extremely difficult issue of recovery of transition costs (discussed *infra*), is the key to reconciling these competing demands.

Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition.[106] Transmitting utilities own the transportation system over which bulk power competition occurs and transmission service continues to be a natural monopoly. Denials of access (whether they are blatant or subtle), and the potential for future denials of access, require the Commission to revisit and reform its regulation of transmission in interstate commerce. As discussed in detail in Section IV.B., such action is required by the FPA's mandate that the Commission remedy undue discrimination.

Since the time the NOPR issued, the Commission staff has completed an FEIS that provides a quantitative estimate of some of the cost savings expected from this Rule: approximately $3.8 to $5.4 billion per year. Other non-quantifiable benefits are also expected from this Rule and include: (1) Better use of existing assets and institutions; (2) new market mechanisms; (3) technical innovation; and (4) less rate distortion. These potential benefits to the Nation's electricity consumers and the economy as a whole confirm the need to take generic action to remove barriers to competition. In what follows, we set out the changes necessary to remedy undue discrimination and to ensure a fair transition to a more competitive regulatory regime.

IV. Discussion

A. Scope of the Rule

1. Introduction

The Commission has determined that non-discriminatory open access transmission services (including access to transmission information) and stranded cost recovery are the most critical components of a successful transition to competitive wholesale electricity markets. These issues are the focal point of this Rule, the accompanying rule on open access same-time information systems, and the accompanying proposed rule on capacity reservation tariffs.

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[100] *See WRTA* and *SWRTA, supra,* and Northwest Regional Transmission Association, 71 FERC ¶ 61,397 (1995).

[101] At least 12 states have retail wheeling proposals, legislation, or pilot programs underway—Alabama, California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire, New York, Ohio, Rhode Island, Vermont, and Wisconsin. At least 14 other states are investigating retail wheeling. Currently, according

to a report of the NARUC-affiliated National Council on competition and the Electric Industry, 41 States are actively involved in investigating whether and how to restructure their respective electric power markets. Of this total, 29 State regulatory authorities * * * have initiated investigations. In addition, five State legislatures are involved in similar investigations, while seven other States have joint regulatory/legislative proceedings underway.

Testimony of the Honorable Cheryl L. Parrino, Chair of the Wisconsin Public Service Commission, on behalf of the National Association of Regulatory Utility Commissioners, before the United States Senate Committee on Energy and Natural Resources (March 6, 1996).

[102] *See* American Electric Power Service Corporation, *et al.*, 72 FERC ¶ 61,287 at 61,238 (1995).

[103] Attached to this Final Rule as Appendix B is a list of commenters and the abbreviations used to designate them, including those commenters that filed late.

[104] Energy Information Administration, *Performance Issues for a Changing Electric Power Industry* (January 1995) 10 and (Figure 5).

[105] Current Competition, November 1994, Vol. 5, No. 8, at 8.

[106] As discussed above, a significant number of public utilities still do not have any form of an ''open access'' tariff on file with the Commission and no public utility has on file a non-discriminatory open access tariff as defined by this Rule.

In undertaking these initiatives, however, we are mindful that they are part of a broader picture of evolving issues affecting the electric industry and that other Commission policies will play an important role in ensuring the full development of competitive markets. Among the many issues that are important to competitive bulk power markets are: independent system operators (ISOs); regional transmission groups; generation market power; utility merger policy; and the development of innovative transmission pricing alternatives, such as flow-based, distance-sensitive transmission pricing methodologies that reflect incremental costs. In particular, we believe that ISOs have great potential to assist us and the industry to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power. Although we discuss some of these issues in this Rule, we will further develop our policies in other proceedings as well to accommodate and encourage more efficient market structures.

We now address the comments received on the scope of the proposed rulemaking.

2. Functional Unbundling

In the NOPR, the Commission preliminarily found that functional unbundling of wholesale generation and transmission services is necessary to implement non-discriminatory open access transmission.[107] At the same time, the Commission explained that the proposed rule would accommodate, but not require, corporate unbundling (which could include selling generation or transmission assets to a non-affiliate (divestiture) or the less aggressive step of establishing separate corporate affiliates to manage a utility's transmission and generation assets). However, we invited comments on functional unbundling and asked whether it is a strong enough measure to ensure non-discriminatory open access transmission without some form of corporate restructuring.

Comments

Commenters take both sides on whether functional unbundling is sufficient to assure non-discriminatory open access transmission or whether a stronger measure, such as corporate unbundling, is needed.

Supporting Functional Unbundling

Various commenters, including utilities and state commissions, generally support functional unbundling as sufficient to assure non-discriminatory open access transmission and oppose requiring corporate unbundling or divestiture.[108] Several commenters state that functional unbundling will remedy discrimination without creating the inefficiencies and additional costs that corporate restructuring would create.[109]

A number of other commenters argue that the Commission has no authority under the FPA to require divestiture of transmission assets.[110] Several of these commenters assert that, even if the Commission has the authority, the electric industry, unlike the natural gas industry, is not ready for mandated corporate unbundling because electric utilities still serve a high percentage of retail customers and own large amounts of the generating capacity. They assert that transmission system operation requires the operator to have control over much of the generating capacity.

Various other commenters also support functional unbundling, but believe that safeguards are needed to make it work.[111] Power Marketing Association, for example, suggests a number of safeguards: adoption of cost allocation mechanisms to ensure that utilities do not shift costs from generation to transmission; random audits of utility books; a requirement that each utility file a code of conduct that provides for maximum separation of generation and transmission functions; and active oversight and complaint procedures with strong penalties for abuse. OK Com and GA Com believe that functional unbundling along with the safeguard of the Commission's complaint process will provide sufficient incentive for non-discriminatory open access transmission.

Supporting Corporate Unbundling

A number of commenters see weaknesses in functional unbundling and argue that some form of corporate unbundling is necessary to assure non-discriminatory open access transmission.[112] American Forest & Paper says that there is affiliate abuse in the gas industry and argues that the electric industry presents even more serious potential for abuse because it is still dominated by vertically integrated utilities.[113] UAMPS asserts that functional unbundling is insufficient because the utility will still favor itself on issues related to transmission planning, capital investment, and operation and maintenance and replacement costs.

NIEP argues that divestiture of generation assets from transmission and distribution is the preferred mechanism for mitigating market power. It further suggests that if corporate divestiture is not feasible the Commission should

> Seek to achieve ''virtual divestiture'' by requiring that the utility generation function be separated from transmission and distribution functions in a separate corporate affiliate, or business unit, and that affiliate transaction rules be established to guard against possible abuses. [114]

It maintains that the Commission has broad authority to protect against undue discrimination and anticompetitive behavior and can order divestiture if such action is required to remedy such behavior.[115]

FTC and DOJ argue that operational unbundling, an example of which is the formation of an independent system operator (ISO), likely would be more effective than functional unbundling and less costly than industry-wide divestiture.[116] FTC describes operational unbundling as ''structural institutional arrangements, short of divestiture, that would separate operation of the transmission grid and access to it from economic interests in generation.'' It gives as an example the California proposal under which utilities would continue to own transmission lines, but an independent system operator would have operational control. DOJ also suggests ''a separate authority'' to

[107] FERC Stats. & Regs. ¶32,514 at 33,080.

[108] *E.g.,* Ohio Edison, UtiliCorp, Pennsylvania P&L, Atlantic City, Montana Power, IL Com, Seattle, OK Com, TX Industrials, MidAmerican, Southwestern, Southern, DOD, Public Service Co of CO, SC Public Service Authority, Florida Power Corp, DOE, WP&L, Com Ed, SBA, Consumers Power, CA Com, UT Com, Houston L&P, KCPL, EEI.

[109] *E.g.,* Florida Power Corp, El Paso, PSNM, and SC Public Service Authority.

[110] *E.g.,* Southwestern, PECO, El Paso, Florida Power Corp, NSP, Public Service E&G, MidAmerican.

[111] *E.g.,* NRECA, IN Com, Power Marketing Association, TDU Systems, NorAm, Turlock, Texaco, Utility Shareholders, NSP, El Paso, Utility Investors Analysts, PECO, Florida Power Corp, UT Com, Sierra, Carolina P&L, SoCal Gas, OK Com, FL Com, Southern.

[112] *E.g.,* American Forest & Power, American National Power, ND Com, IL Com, UAMPS, NIEP, APPA, Public Power Council, Municipal Energy Agency Nebraska, Missouri Basin MPA, Texaco, Direct Services Industries, Calpine, CCEM, Wisconsin Coalition, VT DPS.

[113] *See also* American National Power, ND Com, Calpine.

[114] NIEP Initial Comments at 4.

[115] *See also* Municipal Energy Agency Nebraska, Direct Services Industries.

[116] Others oppose operational unbundling. *See, e.g.,* Carolina P&L, Salt River.

manage the grid and access to the grid, joint ventures, and voluntary pooling arrangements. These commenters argue that operational unbundling would be easier to enforce than functional unbundling.

DOE states that separation of the control of transmission from vertically-integrated companies does not necessarily require a poolco or any particular market mechanism. It suggests the possibility of an ISO that is functionally separate from any buyer or seller of generation, but would not perform all the functions of a poolco.

United Illuminating supports ''operational unbundling'' that would either (1) eliminate vertical integration and divestiture of transmission assets, leading to the formation of a regional transmission company, or (2) develop a regional contractual approach to transmission services that eliminates the transmission owner's market power and fairly allocates support of the transmission facilities between native load and third-party users of the system.

Commission Conclusion

We conclude that functional unbundling of wholesale services is necessary to implement non-discriminatory open access transmission and that corporate unbundling should not now be required. As we explained in the NOPR, functional unbundling means three things:

(1) A public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;

(2) A public utility must state separate rates for wholesale generation, transmission, and ancillary services;

(3) A public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.

We believe that these requirements are necessary to ensure that public utilities provide non-discriminatory service.[117] These requirements also will give public utilities an incentive to file fair and efficient rates, terms, and conditions, since they will be subject to those same rates, terms, and conditions.

However, we recognize that additional safeguards are necessary to protect against market power abuses. Functional unbundling will work only if a strong code of conduct (including a requirement to separate employees involved in transmission functions from those involved in wholesale power merchant functions) is in place. In the RINs NOPR, the Commission proposed a code of conduct that would apply to all public utility transmission providers. As the Commission explained,

> [T]his code of conduct would require, among other matters, a separation of the utilities' transmission system operations and wholesale marketing functions, and would define permissible and impermissible contacts between employees that conduct wholesale generation marketing functions and employees that handle transmission system operations and reliability in the system control center or at other facilities or locations.[118]

Adoption of this code of conduct, discussed in detail in the accompanying final rule on OASIS,[119] is needed to ensure that the transmission owner's wholesale marketing personnel and the transmission customer's marketing personnel have comparable access to information about the transmission system.

As noted by OK Com and GA Com, a further safeguard—section 206—is available if a public utility seeks to circumvent the functional unbundling requirements. Under section 206, any person is free to file a complaint with the Commission detailing any alleged misbehavior on the part of the public utility or its affiliates concerning matters subject to our jurisdiction under the FPA. Similarly, the Commission may, on its own motion, initiate a proceeding to investigate the practices of the public utility and its affiliates.

We believe that functional unbundling, coupled with these safeguards, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time.

Several commenters discuss the need to encourage or even to require ISOs in the context of functional unbundling. We believe that ISOs have the potential to provide significant benefits (*e.g.*, to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power) and will further our goal of achieving a workably competitive market. As we learned at our technical conference on power pools, many utilities are examining ISOs and corporate unbundling in various shapes and forms, particularly in the context of power pools. We discuss ISOs extensively in our section on power pools where we believe they will have an important role to play. However, in the context of individual utility transactions, we believe that the less intrusive functional unbundling approach outlined above is all that we must require at this time. Nevertheless, we see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace.

As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required.

Finally, while we are not now requiring any form of corporate unbundling, we again encourage utilities to explore whether corporate unbundling or other restructuring mechanisms may be appropriate in particular circumstances. Thus, we intend to accommodate other mechanisms that public utilities may submit, including voluntary corporate restructurings (*e.g.*, ISOs, separate corporate divisions, divestiture, poolcos), to ensure that open access transmission occurs on a non-discriminatory basis. We also will continue to monitor—and stand ready to work with parties engaging in—innovative restructuring proposals occurring around the country.

3. Market-Based Rates

a. Market-Based Rates for New Generation

In the NOPR, the Commission proposed to codify its determination in *Kansas City Power & Light Company* [120]

[117] When and how functional unbundling is to be achieved for requirements transactions and for various types of coordination arrangements, including power pools, is discussed at Sections IV.A.5 and IV.F. Functional unbundling of ancillary services is discussed in Section IV.D.

[118] Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking, 60 FR 66182 (December 21, 1995), FERC Stats. & Regs., Proposed Regulations ¶ 32,516 at 33,170 (1995).

[119] The final rule on information systems no longer uses the terminology RINs. The new terminology used is OASIS—Open Access Same-time Information System—which we will use in this Final Rule.

[120] 67 FERC ¶ 61,183 at 61,557 (1994), *reh'g pending (KCP&L).*

that the generation dominance standard for market-based sales from new capacity be dropped.[121] The proposed new section 35.27 would provide:

Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity first placed in service on or after June 10, 1996.[122]

However, this proposal would not affect the Commission's continuing authority to look at whether an applicant and its affiliates could erect other barriers to entry and whether there may be affiliate abuse or reciprocal dealing.[123]

Comments

A number of commenters support the Commission's determination in *KCP&L* [124] and several of them explicitly support the Commission's proposed codification.[125] EEI asserts that more than 50 percent of new generation is from non-utility sources and that recent competitive solicitations for new capacity have been greatly over-subscribed. Entergy argues that there is no evidence in any proceeding thus far of a market power problem in long-run markets.

Other commenters, however, oppose codifying *KCP&L*.[126] They believe that market power in long-run markets exists for both new and old generation due to, for example, constraints on interface capabilities and unduly long notice periods for replacement of purchases. They argue that there is not enough of a distinction between new and old generation to treat them differently. TDU Systems also notes that the Commission in *KCP&L* did not take into account the differences between firm and non-firm bulk power. NIEP and ELCON conclude that the Commission erroneously found in *KCP&L* that no wholesale seller of generation has market power in generation from new facilities. NIEP asserts that in each service area there is usually only one wholesale buyer—the utility—who also is virtually always a wholesale seller of generation. Under these circumstances, NIEP argues that there cannot be arm's-length bargaining. Environmental Action complains that the Commission's proposal to codify *KCP&L* ignores significant factors that impede entry to generation markets, such as utility resistance to purchased power, state government-created barriers to non-utility generation, pancaking of rates under the contract path approach, sunk investment, and scale economies.

Commission Conclusion

In reviewing applications to sell at market-based rates, whether from new (unbuilt) capacity or existing capacity, we require that the seller (and each of its affiliates) must not have, or must have mitigated, market power in generation and transmission and not control other barriers to entry. In order to demonstrate the requisite absence or mitigation of transmission market power, a transmission-owning public utility seeking to sell at market-based rates must have on file with the Commission an open access transmission tariff for the provision of comparable service. In addition, the Commission considers whether there is evidence of affiliate abuse or reciprocal dealing.[127]

In *KCP&L*, we stated that ''in light of industry and statutory changes which allow ease of market entry, we therefore will no longer require rate applicants to submit evidence of generation dominance in long-run bulk power markets.'' [128] We further explained that we had examined ''generation dominance in many different cases over the years'' and had ''yet to find an instance of generation dominance in long-run bulk power markets.'' [129] Commenters have criticized our findings in *KCP&L*, but no commenter has provided any evidence of generation dominance in long-run bulk power markets. Moreover, we have seen no such evidence in any of the market-based rate cases we have considered since *KCP&L*. Based on the comments received, we will codify the Commission's determination in *KCP&L* that the generation dominance standard for market-based sales from new capacity should be dropped. Because the Commission's findings in *KCP&L* applied to long-run markets, we will revise proposed § 35.27 to apply to sales from capacity for which construction has commenced on or after the effective date of this Rule.[130]

The Commission wishes to clarify that dropping the generation dominance standard for new capacity does not affect the demonstration that an applicant must make in order to qualify for market-based rates for sales from its existing generating capacity. In other words, the fact that an applicant need not demonstrate its lack of generation dominance with respect to new capacity cannot be used to ''bootstrap'' the authorization of market-based rates for its existing capacity. Moreover, our evaluation of market-based rates for existing capacity will include consideration of new capacity.

In addition, the fact that we are codifying *KCP&L* does not mean that we will ignore specific evidence presented by an intervenor that a seller requesting market-based rates for sales from new generation nevertheless possesses generation dominance. For example, if the evidence indicated that the new generator, due to its proximity to an existing transmission constraint, could significantly influence the ability to move power across the constraint, we would consider such evidence in determining whether to grant the applicant's request.[131] If such evidence is presented, the Commission will evaluate whether the evidence disproves the premise that the seller lacks generation dominance with respect to its *new capacity*.

If the applicant has existing generation, the sales from which are authorized to be made on a market basis, the Commission would consider whether the new generation (when added to the existing generation with market-based authority) results in the applicant having generation dominance. On the other hand, if the applicant has existing generation, the sales from which are subject to cost-of-service regulation, the Commission would not include this generation in its analysis of the applicant's request for market-based rates for its new generation. The question of whether or not the applicant lacks generation dominance with respect to its existing capacity is relevant only if, and when, the seller applies to the Commission for authority to make wholesale sales for its existing capacity at market-based rates.

If evidence regarding an applicant's generation dominance with respect to

[121] FERC Stats. & Regs. ¶ 32,514 at 33,050.

[122] *Id*. at 33,154.

[123] 67 FERC at 61,557.

[124] *E.g.*, Entergy, EEI, Atlantic City, Duke Centerior, Houston L&P, Montana-Dakota Utilities, Canadian Petroleum Producers, DOE, Florida Power Corp, PSNM.

[125] *E.g.*, EEI, Centerior, Houston L&P, NYSEG.

[126] *E.g.*, TDU Systems, ELCON, NRECA, Environmental Action, NIEP, APPA, Power Marketing Association, EGA.

[127] *See, e.g.*, MidAmerican Energy Company, 74 FERC ¶ 61,211 (1996).

[128] *KCP&L*, 67 FERC at 61,557. *See also* discussion in proposed rule, FERC Stats. & Regs. at 33,067–68.

[129] *Id.*

[130] The NOPR's proposed language that a public utility would not have to demonstrate a lack of market power in generation for sales from capacity first placed in service on or after the date 30 days after the final rule is published in the Federal Register does not properly reflect the finding in *KCP&L*. Because *KCP&L* addressed *new* or *unbuilt* generation, the proposed language is being revised as indicated above and as set forth in the regulatory text included with this Final Rule.

[131] *Cf.* Wisconsin Electric Power Company, et al., 74 FERC ¶ 61,069 at 61,193 (1996).

its new capacity is submitted, the applicant would be required to provide a satisfactory rebuttal.

b. Market-Based Rates for Existing Generation

In the NOPR, the Commission explained that increased competition resulting from open access transmission may reduce or even eliminate generation-related market power in the short-run market (sales from existing capacity).[132] Because market power has been the primary concern of the Commission in analyzing requests for market-based rates for such sales, we sought comments on the effect of industry-wide non-discriminatory open access on our criteria for authorizing power sales at market-based rates. The Commission also sought comments on whether the generation dominance standard should be dropped for market-based sales from existing capacity.

Comments

Many commenters support, but many also oppose, market-based rates for existing generation without a case-specific analysis of generation dominance.

Supporting Market-Based Rates for Existing Generation

Many commenters (primarily IOUs and a number of state commissions) assert that existing generators will not possess market power after implementation of non-discriminatory open access transmission and that market-based rates should be permitted generically for sales from existing generation.[133]

EEI asserts that market power concerns generally would be transitory, limited to the time needed to build new facilities. Thus, it recommends that all markets be declared competitive by a date certain and that market-based rates then be allowed, with customers permitted to file complaints. Florida Power Corp believes that existing procedures under sections 205 and 206 will adequately protect consumers. Other commenters also urge the Commission to eliminate its generation dominance standard, but assert that the Commission should allow a showing of market dominance in a complaint or show cause proceeding.[134] CT DPUC notes that the Commission should be able to rely on rules of conduct, market mechanisms, and monitoring to curb any market power that may exist.

Utilities For Improved Transition argues that if utilities cannot get market-based rates, the new players in the market will have an unfair advantage, since they do not have to carry the traditional utilities' burden of older, less efficient plants.

Entergy proposes a screening test that would permit the Commission to ''deregulate'' wholesale sales to certain short-run markets. CINergy recommends that after industry-wide open access tariffs become effective, the Commission adopt a rebuttable presumption that all markets are workably competitive; that presumption could be rebutted in a section 206 proceeding.[135]

UtiliCorp, while it believes that market power will probably be fully mitigated by open access, also argues that the Commission should examine generation dominance on a region-by-region basis.[136] Montana-Dakota Utilities argues that the Commission should allow all suppliers in a power pool or RTG to have market-based rates after a Commission finding that there is sufficient generation competition within the region.

Duke states that it would be highly inconsistent for the Commission to require open access, but not allow utilities to compete in the market. It further states that the relevant market should be determined using standard antitrust techniques; the Commission should examine the options available to customers and determine whether the utility possesses monopoly power in a relevant market.

Opposing Market-Based Rates for Existing Generation

Many commenters are concerned that even with open access tariffs certain generators will be able to exercise market dominance.[137] For example, NARUC argues that utilities retain market power through their ownership of existing generation and transmission facilities, favorable long-term contracts for fuel and other inputs, and access to superior generation sites.[138] NRECA believes that the universe of generation providers is still too narrow to assume a competitive market and that other factors, such as transmission constraints and pancaking of rates, will inhibit the development of competitive markets.[139] FTC says that, although comparable transmission access could broaden the relevant geographic market for generation, the Commission should not assume that there will be no market power. It says that the Commission must continue to evaluate each case.[140] TDU Systems argues that the Commission cannot move to market-based rates without a Congressional determination that deregulation of wholesale electric rates should be implemented. It further asserts that the Commission does not have a factual basis for a reasoned conclusion that regulated utilities do not have market dominance—full open access is only a goal at this time, and the success of open access will depend upon the transmission rate structures the Commission approves.

LEPA raises concerns that the small bulk power suppliers, QFs, co-generators, EWGs, IPPs, and marketers (who provide non-requirements power) may not be able to bring competition to the wholesale market. LEPA concludes that ''barriers will exist unless buyers have full access to requirements power itself, rather than just to the chance to acquire the individual components of requirements power.'' [141] TDU Systems raises concerns about the limited number of generation providers and the effect of possible future mergers. It also argues that pancaked rates raise the cost of transmission to third parties, thereby restricting the geographic scope of markets. As a result, TDU Systems asserts that individual generators in highly concentrated regions will still be able to exert market power. OH Com expresses concerns that restrictions on siting of generation and transmission will favor nearby generators. SC Public Service Authority argues that if the Commission allows utilities to recover stranded costs their market power will not be mitigated, since customers will

[132] FERC Stats. & Regs. ¶ 32,514 at 33,093–94.

[133] *E.g.*, EEI, CINergy, Central Illinois Public Service, Citizens Utilities, Com Ed, Ohio Edison, Allegheny, Southern, Portland, NRRI, Pennsylvania P&L, PECO, Dayton P&L, Utilities For Improved Transition, Centerior, Houston L&P, Duke, ConEd, IPALCO, Salt River, PJM, NU, NYSEG, Oklahoma G&E, PA Com, OK Com, CT DPUC, CA Com, MT Com.

[134] *E.g.*, Consumers Power, Portland, Dayton P&L, CSW.

[135] *See also* Citizens Utilities.

[136] *See also* CSW, Industrial Energy Applications, Public Service Co of CO, Coalition for Economic Competition.

[137] *E.g.*, NRECA, TDU Systems, MT Com, SMUD, NEPCO, Orange & Rockland, El Paso, American Forest & Paper, NIPSCO, AEC & SMEPA, OH Com, IL Com, IN Com, Legal Environmental Assistance, LG&E, Cajun, Industrial Energy Applications, LEPA, MA DPU, MI Com, FTC, Minnesota P&L, SC Public Service Authority, WP&L, NARUC, Canadian Petroleum Producers, DOD, CCEM, Environmental Action, American Wind, Cajun, NIEP, EGA, TAPS, ELCON, Consolidated Natural Gas.

[138] *See also* NIEP, Pacificorp, CA Energy Com.

[139] *See also* MT Com, TDU Systems, Soyland.

[140] *See also* AEC & SMEPA, NIPSCO, El Paso (discusses a particular transmission constraint that it states limits its access to suppliers).

NRECA is also concerned that mergers may create a handful of ''mega-public utilities'' that may affect a regional generation market and that the Commission should apply more traditional antitrust principles in analyzing the impacts of mergers.

[141] LEPA Initial Comments Affidavit of William G. Shepherd at 4.

have to pay exit fees to switch suppliers.[142]

CCEM notes that in Order No. 636 gas pipelines were not allowed market-based rates for merchant sales until after transmission had been completely unbundled and non-discriminatory open access had been fully implemented.

DOE and DOJ assert that open access should not be assumed to mitigate market power sufficiently to justify deregulation of existing generation—structural changes, such as control of the regional grid by an independent entity, are required. DOE requests that the Commission continue to look for affiliate abuse when reviewing market-based rates for new generation. Similarly, EPA is concerned that even with open access, individual generators may still exert market power by their domination of a particular geographic market. It is also concerned that low-cost plants that are subject to weaker environmental standards could have a market advantage. NEPOOL Review Committee requests that the Commission not approve any market prices ''where the market into which the seller proposes to sell is not effectively competitive due to the absence of regional transmission products and prices.''[143]

Commission Conclusion

While the Commission expects this Rule to facilitate the development of competitive bulk power markets, we find that there is not enough evidence on the record to make a generic determination about whether market power may exist for sales from existing generation. We continue to have concerns about how to define the relevant markets and believe that a more rigorous analysis is needed than can be achieved with the limited market data that is now available. We will continue our case-by-case approach that allows market-based rates based on an analysis of generation market power in first tier and second tier markets.[144] In particular cases, however, the effect of the mandatory open access prescribed by this Final Rule may lead to the consideration of geographic markets for the applicant's generation products that are broader in scope than the first-tier and second-tier markets currently considered.[145] By the same token, in some cases, evidence of the effects of transmission constraints may circumscribe the scope of the relevant geographic market for the applicant's generation products.

While we will continue to apply the first-tier/second-tier analysis, we will allow applicants and intervenors to challenge the presumption implicit in the Commission's practice that the relevant geographic market is bounded by the second-tier utilities. Thus, for instance, applicants may present evidence that the relevant market is in fact broader than the first or second tier. In support of such a contention, an applicant would need to show more than the existence of open access. For example, an applicant might attempt to demonstrate the lack of significant transmission constraints in the more broadly defined market and that cumulative transmission rates would not significantly affect the ability of more distant suppliers to compete in the relevant market. Similarly, an intervenor may present evidence that, due to the existence of significant transmission constraints within the first- and second-tier markets, the relevant market is in fact more limited in scope.[146]

Finally, we will maintain our current practice of allowing market-based rates for existing generation to go into effect subject to refund. To the extent that either the applicant or intervenors in individual cases offer specific evidence that the relevant geographic market ought to be defined differently than under the existing test, we will examine such arguments through formal or paper hearings.

Because our goal is to develop more competitive bulk power markets, we will continue to monitor markets to assess the competitiveness of the market in existing generation, and we will modify our market rate criteria if and when appropriate. However, any changes we might make to our analysis for authorizing market-based rates in the future will not upset transactions entered into pursuant to existing market-based rate authority. The policies we put in place today to develop a smoothly functioning transmission access regime will provide useful experience and information for assessing the effects of generation concentration.

4. Merger Policy

In the NOPR, the Commission did not address possible ramifications of the NOPR with regard to its existing merger policy.

Comments

A number of commenters suggest that the Commission should reevaluate its merger policy in light of the NOPR.[147] They further suggest a number of changes that they believe need to be made to the Commission's existing merger policy.

Most commenters raising this issue express concerns that mergers will lessen competition and hinder achievement of competitive bulk power markets.[148] For example, NRECA indicates that the Commission's merger policy is at a crossroads. It believes that it is essential for the Commission to reevaluate its merger policy in concert with the proposed rulemakings.[149] Similarly, TAPS recommends that the Commission reevaluate its merger criteria to ensure that in a more competitive era, mergers are found to be consistent with the public interest only if they are pro-competitive. Several commenters argue that the Commission should continue to conduct a case-by-case investigation of the product and geographic markets that will be affected by a proposed merger.[150]

A number of commenters also suggest certain changes that they would like to see in the Commission's merger policy.[151] APPA recommends that, at a minimum, all merger approvals considered by the Commission should be conditioned on: (1) Filing an open access transmission tariff, (2) demonstrating no market power in generation or ancillary services, and (3) granting all existing requirements customers of the merged entity the right to convert existing contracts to rights to equivalent transmission capacity. Several commenters suggest adopting the U.S. Department of Justice Merger

[142] *See also* DOD and WP&L. IL Com suggests that the Commission allow market-based rates to a utility on the condition that the utility forego stranded cost recovery.

[143] NEPOOL Review Committee Initial Comments at 28.

[144] *See, e.g.*, Southwestern Public Service Company, 72 FERC ¶ 61,208 at 61,996 (1995).

[145] The Commission's practice is to define the relevant markets as those utilities directly interconnected to the applicant (first-tier markets). For each first-tier market, we consider all utilities interconnected to the first-tier utility and all utilities interconnected to the applicant as competitors in that relevant market. Thus, the competitors include the second-tier utilities directly interconnected to the relevant market and those other first-tier utilities that can reach the market by virtue of the applicant's open access transmission tariff. *See, e.g.*, Kansas City Power & Light Company, 67 FERC ¶ 61,183 at 61,556; and Heartland Energy Services, Inc., 68 FERC ¶ 61,223 at 62,061.

[146] *See* Wisconsin Public Service Corporation, 75 FERC ¶ 61, ______, slip op. at 6–7 (1996).

[147] *E.g.*, NRECA, TAPS, Wisconsin Coalition, APPA.

[148] *E.g.*, Wisconsin, Rosebud, NRECA, IN Com, Wisconsin Coalition, NIEP, Minnesota P&L, APPA.

[149] *See also* APPA.

[150] *E.g.*, Wisconsin Coalition, MMWEC.

[151] *E.g.*, APPA, Wisconsin Coalition, Minnesota P&L, IN Com.

Guidelines in analyzing merger proposals.[152]

Environmental Action and others contend that merging utilities must be required to demonstrate real net benefits to retail and wholesale customers that could not otherwise be achieved but for the proposed merger.[153]

Commenters also argue that the Commission should use its merger conditioning authority to order divestiture of transmission and generation when required to ensure competition.[154] Environmental Action and NEPOOL Review Committee suggest conditioning merger applications on the existence of regional transmission pricing arrangements to mitigate any generation market power gained by the merging entities.

Commission Conclusion

The Commission appreciates the concerns and suggestions raised with respect to our merger policy. However, since the time the NOPR was issued (and comments received thereon), we issued a Notice of Inquiry on the Commission's merger policy in Docket No. RM96–6–000.[155] There we indicated that we will review whether our criteria and policies for evaluating mergers need to be modified in light of the changing circumstances, including this final rule, that are occurring in the electric industry. The NOI proceeding will permit us to consider comments from *all* interested participants and, at the same time, allow us to review our merger criteria and policies in light of this final rule. We are committed to reviewing our merger policy in a timely manner in the ongoing NOI proceeding.[156]

5. Contract Reform

In the NOPR, the Commission explained that it believed that it could remedy unduly discriminatory practices and achieve more competitive bulk power markets without abrogating existing wholesale power supply contracts that bundle generation and transmission services and existing wholesale transmission contracts.[157] Thus, we proposed to apply the functional unbundling requirement only to transmission services under new requirements contracts, new coordination contracts, and new transactions under existing coordination contracts. However, the Commission did invite comment on whether it would be contrary to the public interest to allow all or some of the above types of existing contracts to remain in effect.

Comments

Requirements and Transmission Contracts

Many of the commenters (including utility customers and third-party power suppliers) addressing this issue oppose abrogating existing contracts on a generic basis.[158] A number of the commenters contend that existing contracts should be retained because they are the result of mutually beneficial bargaining.[159] SMUD and TANC are concerned that existing contracts providing for transmission service that is superior to the pro forma tariffs not be abrogated.[160] Ohio Edison argues that existing contracts have contributed to the emergence of competition, meet the specific needs of the parties, have been approved by the Commission, and have not been found to be unduly discriminatory or violative of the public interest, and that their preservation is consistent with the Energy Policy Act, most notably amended section 211 of the FPA. PacifiCorp and AEP express concern that contract abrogation would create competitive instability. American Forest & Paper argues that the Commission cannot refuse to honor existing contracts if it expects a competitive bulk power market to emerge.

Numerous commenters further argue that contract abrogation requires a fact-based, contract-specific evaluation, and they oppose any generic declaration that existing contracts are contrary to the public interest.[161] Some suggest that generic contract abrogation cannot be justified under the public interest standard.[162]

Missouri Basin MPA argues that the Commission should allow abrogation of existing wholesale power and transmission arrangements if the customer can demonstrate the undue competitive disadvantage caused by the arrangement.

A few commenters support some form of generic contract abrogation.[163] CCEM asserts that existing wholesale requirements customers must be given the right to convert to transmission service under non-discriminatory open access tariffs.[164] CCEM notes that this is the same relief from undue discrimination that the Commission afforded to pipeline customers in Order Nos. 436 and 500.[165] CCEM emphasizes that here, in contrast to what occurred in the gas industry, ''[c]onversion rights should be understood as the logical *quid pro quo* for introducing extra-contractual stranded-cost recovery rights into the wholesale requirements contracts of electric utilities.'' [166] NRECA asserts that it would be unduly discriminatory to allow new transmission customers to use the open access transmission tariffs, but not allow existing customers the same access.[167]

TAPS says that if those who now have discriminatory contracts are forced to live with those contracts, a fully competitive market will be delayed considerably.[168] Moreover, TAPS argues, the Commission has a statutory duty to remedy the undue discrimination that it is only now recognizing. Even if the Commission will not abrogate these contracts across the board, TAPS asserts that we should use our section 206 authority to do so on a contract-by-contract basis.

San Francisco requests that the Commission clarify that a holder of capacity rights under an existing

[152] *E.g.,* Wisconsin Coalition.

[153] *E.g.,* TAPS, Wisconsin Coalition.

[154] *E.g.,* NIEP, Wisconsin Coalition, TAPS, Environmental Action.

[155] FERC Stats. & Regs. ¶ 35,531 (1996).

[156] Our decision to review our merger policy in a separate NOI proceeding is not intended to affect a utility's business decision of whether a merger may be in the economic interest of its ratepayers and stockholders. The NOI proceeding will not prevent us from reviewing merger applications in as timely a manner as possible.

[157] FERC Stats. & Regs. ¶ 32,514 at 33,093.

[158] *E.g.,* Dayton P&L, NSP, Montaup, Southwestern, Ohio Edison, Consumers Power, Allegheny, Public Generating Pool, NEPCO, Pennsylvania P&L, Southwest TDU Group, Arizona, DOD, El Paso, Florida Power Corp, AEC & SMEPA, Atlantic City, Texaco, Tampa, CSW, Central Illinois Public Service, CA Cogen, ConEd, GA Com, Consolidated Natural Gas, Ohio Valley, Pacific Northwest Coop, Salt River, Oglethorpe, Minnesota P&L, NYSEG, Brazos, Southern, Washington Water Power, CINergy, SoCal Edison, Hoosier EC.

[159] *E.g.,* AEC & SMEPA, Cajun, Carolina P&L, NSP, Pennsylvania P&L, UNITIL, Southwestern, CSW.

[160] *See also* Dairyland, DE Muni, Arkansas Cities, Ohio Valley.

[161] *E.g.,* AEP, Associated EC, DOD, El Paso, NEPCO, Ohio Edison, PSNM, Southwest TDU Group, Utilities For Improved Transition, NYSEG, Citizens Utilities, NM Com, EGA. *See also* NRECA, TDU Systems, Blue Ridge, CCEM, Industrial Energy Applications, APPA, Cajun, Springfield, DE Muni, Missouri Basin MPA, TANC, Wolverine Coop Members, FL Com, Citizens Utilities, Soyland (support contract abrogation on a case-by-case basis).

[162] *E.g.,* Utilities For Improved Transition, NSP, Southwestern, DE Muni.

[163] *E.g.,* NRECA, CCEM, ELCON, DE Muni, Oglethorpe. Portland maintains that it would be in the public interest to abrogate existing contracts completely, but recommends that such action be taken only on a case-by-case basis.

[164] *See also* VT DPS, NYMEX.

[165] *See also* VT DPS, Portland.

[166] CCEM Initial Comments at 26. *See also* ELCON, VT DPS, Blue Ridge, NYMEX, OK Com, Missouri Basin MPA, Texas-New Mexico, TDU Systems.

[167] *See also* TDU Systems, Texas-New Mexico, TAPS, Wisconsin Municipals.

[168] *See also* NorAm. UtiliCorp argues that existing contracts should not be allowed to extend indefinitely (as through ''evergreen'' clauses) without adopting comparability. *See also* Texaco, Wisconsin Municipals, Phelps Dodge.

contract can extend contractual rights to transmission access at least coterminous with the life of the project and under a roll-over or renewal contract on the same basis as provided in the existing contract. Anoka EC proposes that when a wholesale purchaser's contract expires, it should have a right of first refusal to contract for the transmission capacity to which it previously had a right. Knoxville urges the Commission to require renegotiation of the notice and/or term of all existing contracts for which the voluntary termination period exceeds the time frame for implementation of the final rule.

NEPCO suggests that we require existing power contracts that allow rate changes to be separated into their generation and transmission components, without otherwise disturbing their terms; this would allow comparisons between the transmission service the utility provides to its power customers and the service it offers to others.[169]

Coordination Agreements

CINergy argues that coordination agreements should not be excluded from the comparability standard and that the Commission should use its authority under section 206 to require amendments to such agreements, just as it did in Order 636 in requiring unbundling of pipeline supply contracts. CINergy suggests that public utilities should be given up to three years to file the amendments to avoid hardship on the industry and the Commission's staff. CINergy further asserts that future transactions conducted under coordination agreements should be unbundled and the transmission component subjected to the comparable transmission service requirement.

Others argue that purchases under existing coordination agreements made on behalf of retail native load should not be unbundled.[170] NY Com and IL Com recommend that proposed § 35.28(c) be modified to state that the functional unbundling requirement ''exclude(s) those wholesale purchases made by the utility to serve existing or expected native retail load.''

Utilities For Improved Transition disagrees with the idea that new transactions under existing coordination agreements should be subject to the rule.[171] It argues that the sanctity of coordination contracts should be the same as for other contracts. Coordination contracts are not simply agreements to agree in the future, according to Utilities For Improved Transition; they set forth terms and rates and merely leave the timing of transactions to be resolved in the future. Moreover, it argues that the Commission has given no reason to abandon its practice of encouraging coordination sales by allowing price flexibility.

Commission Conclusion

Requirements and Transmission Contracts

We do not believe it is appropriate to order generic abrogation of existing requirements and transmission contracts. While the Commission did generically find it appropriate to modify natural gas contracts to complete the move to a competitive commodity market in natural gas, we face a different situation here. At the time the Commission addressed this situation in the natural gas industry, it was faced with shrinking natural gas markets, statutory escalations in natural gas ceiling prices under the Natural Gas Policy Act, and increased production of gas.[172] In other words, there was a market failure in the industry that required the extraordinary measure of generically allowing all customers to break their contracts with pipelines.

In contrast, there is no such market failure in the electric industry. Although changes in the industry have been and continue to be dramatic, we do not believe they compel generic abrogation of requirements and transmission contracts.[173]

While we have concluded that current conditions in the wholesale power market do not warrant the generic modification of requirements contracts, we conclude nonetheless that the modification of certain requirements contracts on a case-by-case basis may be appropriate. We conclude further that, even if customers under such contracts are bound by so-called *Mobile-Sierra* clauses, they nonetheless ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

The Commission finds that it would be against the public interest to permit a *Mobile-Sierra* clause in an existing wholesale requirements contract to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. For purposes of this finding, the Commission defines existing requirements contracts as contracts executed on or before July 11, 1994.[174] By operation of this finding, a party to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

This finding complements the Commission's finding that, notwithstanding a *Mobile-Sierra* clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule.[175] The Commission's complementary *Mobile-Sierra* findings are not mutually exclusive. Any contract modification approved under this Section shall provide for the utility's recovery of any costs stranded consistent with the contract modification. The stranded costs must be prudently incurred, legitimate and verifiable, as provided in Section IV.J. Further, the Commission has concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

The Commission believes that the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. Thus, if the selling public utility intends to claim stranded costs, it must present that claim in any section 206 proceeding brought by the customer to shorten or terminate the contract. Similarly, if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded

[169] *See also* Industrial Energy Applications.

[170] *E.g.*, Con Ed, Detroit Edison, IL Com.

[171] *See also* Utility Workers Union, VEPCO.

[172] *See* Pierce, Richard J., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 Energy L.J. 1 (1988).

[173] In addition, we do not believe that unfavorable requirements contracts will derail the attainment of competitive wholesale power markets. Indeed, many of the commenters support this position and seek to retain their existing requirements contracts.

[174] This is consistent with the definition of existing requirements contracts we have used for purposes of stranded cost recovery.

[175] *See* Section IV.J.5.

costs. This will promote administrative efficiency and will permit the Commission to consider how the contracting parties' claims bear on one another.

The Commission does not take contract modification lightly. Whether a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, or a customer is seeking to shorten or eliminate the term of an existing contract, we believe that each has a heavy burden in demonstrating that the contract ought to be modified. Still, we believe that given the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants. The Commission expects that many of the arguments presented by buyers and sellers in such proceedings will be fact specific.

We note that because we are not abrogating existing requirements and transmission contracts generically and because the functional unbundling requirement of the Final Rule applies only to new wholesale services, the terms and conditions of the Final Rule pro forma tariff do not apply to service under existing requirements contracts. However, if a customer's existing bundled service (transmission and generation) contract or transmission-only contract expires, and the customer takes any new transmission service from its former supplier, the terms and conditions of the Final Rule tariff would then apply to the transmission service that the customer receives.

A further issue concerning firm contract customers is their right to transmission capacity (and the rate for such capacity) when their contracts expire by their own terms or become subject to renewal or rollover. We have concluded that *all* firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider. The limitations are that the underlying contract must have been for a term of one-year or more and the existing customer must agree to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at least as long as that offered by the potential customer.[176] This means that there is no right to grandfather the historical price of the transmission service. Thus, if not enough capacity is available to meet all requests for service, the right of first refusal gives the capacity to the existing customer who had contractually been using the capacity on a long-term, firm basis, assuming that it meets the conditions set forth above. Moreover, this limited right of first refusal is not a one-time right of first refusal for contracts existing as of the date of the final rule, but is an ongoing right that may be exercised at the end of all firm contract (including all future unbundled transmission contracts) terms. A customer converting existing bundled service to the Final Rule pro forma tariff would not have a reservation priority for capacity expansions, unless the existing contract provides for future transmission to the customer that requires capacity expansion.[177]

Finally, with respect to all existing requirements contracts and tariffs that provide for bundled rates, we will require all public utilities to make informational filings setting forth the unbundled power and transmission rates reflected in those contracts and tariffs. These informational rates must be submitted to the Commission within 60 days of publication of the Final Rule in the Federal Register and must also be included as a line item on all bills submitted to wholesale customers in the third month following the effective date of this final rule. The unbundled informational rates will permit wholesale customers to compare rates in anticipation of their contracts expiring so that they can evaluate alternative contracts.

Coordination Agreements

The situation as to coordination agreements requires a slightly different approach.[178] While we also believe that as a general matter it is important not to generically abrogate any coordination agreements, this is particularly true for non-economy energy coordination agreements that may reflect complementary long-term obligations among the parties. This type of agreement presents special problems and, as discussed below, we will not generically require this type of coordination agreement to be modified.[179]

Hundreds of coordination agreements exist in the industry today. Many are open-ended agreements that permit new transactions to occur well into the future. Because these contracts may not expire of their own terms in a reasonable time, they may present a larger and more enduring obstacle to non-discriminatory open access and more competitive bulk power markets. Thus, to assure that non-discriminatory open access becomes a reality in the relatively near future, we will partially modify existing economy energy coordination agreements. We will condition future sales and purchase transactions under existing economy energy coordination agreements [180] to require that the transmission service associated with those transactions be provided pursuant to this Rule's requirements of non-discriminatory open access, no later than December 31, 1996.[181] We also will require that for new economy energy coordination agreements [182] where the transmission owner uses its transmission system to make economy energy sales or purchases, the transmission owner must take such service under its own transmission tariff as of the date trading begins under the agreement.[183]

[176] This right of first refusal exists whether or not the customer buys power from the historical utility supplier or another power supplier. If the customer chooses a new power supplier and this substantially changes the location or direction of its power flows, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change.

[177] The above discussion on a right of first refusal addresses firm contract customers. However, the same logic applies to retail customers.

[178] For purposes of this discussion, we define coordination agreements as all power sales agreements, except requirements service agreements. In addition, for purposes of implementing the non-discriminatory, open access requirements of the Final Rule, we are dividing bilateral coordination agreements into two general categories: (1) *Economy energy coordination agreements* are contracts and service schedules thereunder that provide for trading of electric energy on an ''if, as, and when available'' basis, but do not require either the seller or buyer to engage in a particular transaction; and (2) *non-economy energy coordination agreements* are any non-requirements service agreements, except economy energy coordination agreements.

[179] The requirements for power pools and other multilateral arrangements are discussed in detail in Section IV.F.

[180] Those executed prior to 60 days after publication of the Open Access Rule in the Federal Register.

[181] The requirement to unbundle future transactions under existing economy energy coordination agreements means that if the transmission owner uses its transmission system to make economy energy coordination sales or purchases, it must take service for these transactions under its own transmission tariff after December 31, 1996.

[182] Those executed 60 days after publication of the Open Access Rule in the Federal Register.

[183] Accordingly, transmission service needed for sales or purchases under *all* new economy energy coordination agreements will be pursuant to the Final Rule pro forma tariff.

Finally, we will treat non-economy energy coordination agreements differently. We will not require their modification. However, this does not insulate such agreements from complaints that transmission service provided under such agreements be provided pursuant to the Final Rule pro forma tariff.

With respect to coordination pricing practices, we conclude that non-discriminatory open access consistent with the requirements of this Rule is necessary if we are to allow utilities to continue to use market-driven pricing, such as split-the-savings pricing, for coordination sales. Absent such non-discriminatory open access, a utility would be able to deny access to others so as to obtain a higher price for its own power sales.

6. Flow-Based Contracting and Pricing

In the NOPR, the Commission discussed the procedures to be used in establishing Stage One rates. These Stage One rates were proposed as an administrative convenience. The proposal merely followed the long-established practice of establishing rates on the basis of contract path pricing.[184] The Commission made no determination with respect to the appropriateness of flow-based pricing or contracting for other purposes.[185]

Comments

Most of the commenters addressing this issue recommend that industry or the Commission—either in this rule or ultimately—dispense with the traditional contract path basis for pricing and contracting. Most commenters also recommend that the Commission adopt or encourage a regional approach to the solution of transmission pricing problems, though they differ markedly in how to account for flows.[186]

Transmission customers generally seek to rid themselves of ''pancaked'' transmission rates that are associated with the traditional approach to transmission pricing.[187] They propose the development of regionwide transmission rates, perhaps determined on a pool or RTG basis. Most, however, do not discuss how to account for unscheduled flows.[188]

Many transmission providers, some regulatory authorities, and some individuals strongly support flow-based pricing. Most of these commenters recognize a need for a regional approach to resolve transmission pricing concerns.[189] However, many of them also appear to accept contract pricing in the near term because of the need to implement open access quickly.[190] NERC recommends that the Commission maintain an open position on the transfer scheduling process and supports changes in the process to reflect actual power flows. EEI suggests that the Commission should be willing to deviate from a contract path approach, since competition may be accompanied by greater unscheduled flows and contract pricing is not well equipped to deal with such flows. However, EEI concludes that a single approach to pricing will not be appropriate for all systems.

Other commenters, however, do raise concerns with respect to flow-based pricing. AEC & SMEPA considers flow-based pricing to be flawed because that method makes an individual customer responsible for load flow effects caused by a third party's development of the third-party's transmission system over which the customer and its transmission provider had no control. Dayton P&L fears that competition would be lessened under flow-based pricing because utilities with large transmission systems would dominate the market.

Several commenters oppose Southern's and United Illuminating's flow-based proposals, arguing that the methodologies are based on estimates of actual flows or a set of conditions with limited applicability. Various commenters also believe that a single rate is flawed and could cause just as many problems as contract path pricing.[191]

Most commenters appear to believe that the Commission endorsed contract path pricing in the NOPR. Hogan expresses concern that many industry participants' understanding of the pro forma tariffs is based on the fiction of the contract path. The MT Dept of Environmental Quality believes that despite the Commission's pledge to consider innovative pricing proposals,[192] such proposals will receive heavy scrutiny, while conventional contract path pricing proposals will receive nearly automatic approval. Dominion is concerned that relying on the initiative of individual transmission owners to develop flow-based pricing will yield slow and patchy results.

Commission Conclusion

We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach—such as a shift to some form of flow-based pricing and contracting—could severely slow, if not derailed for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule.

While we are not requiring the use of any form of flow-based pricing, we recognize that some versions of flow-based pricing could have benefits. For example, some versions of flow-based pricing could more accurately reflect and price the actual power flows on transmission systems and thus could produce efficiency gains, better generation siting decisions, and benefits for customers and utilities alike. Other versions could more accurately assign capacity rights in accordance with a party's contribution to capacity costs.

These potential benefits, however, will not simply come about in the abstract. Flow-based pricing methodologies that will achieve the benefits sought by most of the

[184] A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path.

[185] Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the ''unscheduled flows'' that occur under a contract path regime.

[186] *E.g.,* APPA, TAPS, NY Energy Buyers, Arcadia, Brownsville, Detroit Edison Customers, AMP-Ohio, Michigan Systems.

[187] *E.g.,* AMP-Ohio, NRECA, APPA, Detroit Edison Wholesale Customers, MMWEC, Missouri Basin MPA, Air Liquide, American Wind Energy, Associated Power, CCEM.

[188] Some commenters propose the development of a regional rate on a postage stamp basis, without regard to distance travelled or the actual path of power flows. *E.g.,* Air Liquide, American National Power, CA Energy Co. Several commenters do, however, propose ways to account for unscheduled flows. *E.g.,* American Forest & Paper, DE Muni, Lower Colorado River Authority.

[189] *E.g.,* CSW, EDS Utilities, Dominion, CINergy, KS Com, CT DPUC, Com Ed, Hogan.

[190] NYMEX favors contract path pricing because of its familiarity and believes that the issue should primarily be resolved by the transmitting utilities. AEP believes that the primary responsibility lies with industry to develop alternative pricing structures.

[191] *E.g.,* NU, NEPCO, BECO, Florida Power Corp.

[192] *See* FERC Stats. & Regs. ¶ 31,005.

participants in the industry are in a development stage and require further work and refinement to address some of the difficulties associated with flow-based approaches. Concurrent work on OASIS and resolving available transmission capability issues may help resolve flow-based issues. However, as demonstrated by the paucity of possible methodologies presented in the comments, developing workable methodologies will be difficult. As we explained in our Transmission Pricing Policy Statement, we are receptive to proposals for alternative rate methodologies, such as distance-sensitive and flow-based pricing, as long as the proposals are well supported. However, we have yet to receive a formal rate application for a flow-based pricing methodology that has been tested enough that it can be required on a generic basis. Thus, we have decided to go forward to achieve open access and more competitive wholesale bulk power markets without waiting for the development of a generic flow-based pricing methodology.

We wish to emphasize further that in taking this approach we are not endorsing the traditional contract path approach as the *only* available approach. We continue to approve contract path pricing because it is the long-established pricing method that comes to us in rate filings by the electric industry, is administratively convenient and feasible, and thus is a practical way to move forward now. We remain open to alternative methodologies, but need to see better developed approaches from the industry before we can consider generic adoption of alternative pricing.

We also believe the adoption of flow-based pricing will be more practical on a regional, instead of individual utility, basis. Some forms of flow-based pricing may even require a regional approach. To this extent, regional ISOs could be a valuable mechanism for implementing such pricing reforms.

B. Legal Authority

The Commission reaffirms its conclusion in the NOPR that we have the authority under the FPA to order wholesale transmission services in interstate commerce to remedy undue discrimination by public utilities. We analyze below the relevant cases examining our wheeling authority, then discuss and respond to the legal arguments raised by the commenters.

1. Bases for Legal Authority

a. Undue Discrimination/ Anticompetitive Effects

In upholding the Commission's order requiring non-discriminatory open access in the natural gas industry, the court in *Associated Gas Distributors* v. *FERC* stated that the Natural Gas Act "fairly bristles" with concern for undue discrimination.[193] The same is true of the FPA. The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. As discussed below, *AGD* demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access [194] as a remedy for undue discrimination. The *AGD* court reached this decision even in the face of prior cases that acknowledged that Congress did not mandate common carriage or explicitly empower the Commission to order direct access for either gas transporters or electric utilities. Moreover, the Commission's power under the FPA "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to (FPA) sections 202 and 203, and under like directives contained in sections 205, 206, and 207." [195]

Therefore, based on the mandates of sections 205 and 206 of the FPA and the case law interpreting the Commission's authority over transmission in interstate commerce, we conclude that we have ample legal authority—indeed, a responsibility—under section 206 of the FPA to order the filing of non-discriminatory open access transmission tariffs if we find such order necessary as a remedy for undue discrimination or anticompetitive effects.[196] We discuss below the primary court decisions that touch on our wheeling authority under sections 205 and 206.

The Commission's authority to order access as a remedy for undue discrimination under the Natural Gas Act (NGA) was upheld and discussed in detail in *AGD*. In *AGD*, the court upheld in relevant part the Commission's Order No. 436.[197] That order found the prevailing natural gas company practices to be "unduly discriminatory" within the meaning of section 5 of the NGA (the parallel to section 206 of the FPA) and held that if pipelines wanted blanket certification for their transportation services, they must commit to transport gas for others on a non-discriminatory basis; in other words, they must provide non-discriminatory open access.

In upholding the Commission's authority to require open access, the court first noted that the opponents' arguments against such authority must proceed "uphill." The statute contains no language forbidding the Commission to impose common carrier status on pipelines, let alone forbidding the Commission to impose "a specific duty that happens to be a typical or even core component of such status." The court found that the legislative history cited by the opponents came nowhere near overcoming this statutory silence. Rather, the legislative history supported only the proposition that Congress itself declined to impose common carrier status.[198] Emphasizing Congress' deep concern with undue discrimination, the court found that the Commission had ample authority to "stamp out" such discrimination:

> The issue seems to come down to this: Although Congress explicitly gave the Commission the power and the duty to achieve one of the prime goals of common carriage regulation (the eradication of undue discrimination), the Commission's attempted exercise of that power is invalid because Congress in 1906 and 1914 and 1935 and 1938 itself refrained from affixing common carrier status directly onto the pipelines and from authorizing the Commission to do so.

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[193] Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) (*AGD*).

[194] We use the term "open access" to refer to a public utility's obligation to put a tariff on file offering service to eligible customers. Access is not open to all. Specifically, the tariff is not an offer to serve retail customers if state law does not permit retail wheeling.

[195] Gulf States Utilities Company v. FPC, 411 U.S. 747, 758–59 (1973).

[196] In most situations, discrimination that precludes transmission access or gives inferior access will have at least potential anticompetitive effects because it limits access to generation markets and thereby limits competition in generation. Similarly, it is probable that any transmission provision that has anticompetitive effects would also be found to be unduly discriminatory or preferential because the anticompetitive provision would most likely favor the transmission owner *vis-a-vis* others.

[197] Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs., Regulations Preambles ¶ 30,665 (1985).

[198] *AGD*, *supra*, 824 F.2d at 997.

And this proposition is said to control no matter how sound the Order may be as a response to the facts before the Commission. We think this turns statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one.[199]

The *AGD* court found that court decisions under the FPA did not support the view that the Commission's authority to ''stamp out'' undue discrimination is hamstrung by an inability to require non-discriminatory open access as a remedy. These decisions are discussed below.

One of the earliest cases on wheeling is *Otter Tail Power Company* v. *United States (Otter Tail)*.[200] In that case, the Supreme Court rejected the argument that the District Court, in a civil antitrust suit, could not order wheeling because to do so would conflict with the FPC's purported wheeling authority.[201] The Court explained that Congress had decided not to impose a common carrier obligation on the electric power industry and noted that the Commission was not at that time expressly granted power to order wheeling.[202] In effect, it concluded that because Congress did not include common carrier provisions in the FPA, the Commission must not have any express authority to order wheeling that would preclude the District Court from imposing a wheeling remedy. Nowhere, however, did the Court say that the Commission lacked authority under section 206 to remedy undue discrimination. Indeed, that was simply not a matter before the Court or of any consequence to its decision.

In the FPA, while Congress elected not to impose common carrier status on the electric power industry, it tempered that determination by explicitly providing the Commission with the authority to eradicate undue discrimination—one of the goals of common carriage regulation.[203] By providing this broad authority to the Commission, it assured itself that in preserving ''the voluntary action of the utilities'' it was not allowing this voluntary action to be unfettered. It would be far-reaching indeed to conclude that *Otter Tail*, which was a civil antitrust suit that raised issues entirely unrelated to our authority under section 206, is an impediment to our achieving one of the primary goals of the FPA—eradicating undue discrimination in transmission in interstate commerce in the electric power industry.

In *Richmond Power & Light Company* v. *FERC* (*Richmond*),[204] the FPC, in reaction to the 1973 oil embargo, was attempting to reduce dependence on oil. The FPC requested that utilities with excess capacity wheel power to the New England Power Pool (NEPOOL). In response, several suppliers and transmission owners filed rate schedules with the FPC that provided for voluntary wheeling. Richmond Power & Light Company (Richmond) objected to these filings, claiming that they were unreasonable because they did not guarantee transmission access. The FPC refused to compel the utilities to wheel Richmond's power, stating that it did not have the authority to order a public utility to act as a common carrier.

The D.C. Circuit upheld the Commission. It acknowledged that Richmond's argument was persuasive in some respects, but stated that any conditions the Commission might impose could not contravene the FPA. The court examined the legislative history of the FPA and stated that ''[i]f Congress had intended that utilities could inadvertently bootstrap themselves into common-carrier status by filing rates for voluntary service, it would not have bothered to reject mandatory wheeling * * *.''[205]

However, the D.C. Circuit in no way indicated that the Commission was foreclosed from ordering transmission as a remedy for undue discrimination. Richmond also had argued that the alleged refusal of the American Electric Power Company (AEP) and its affiliate, Indiana & Michigan Electric Company (Indiana), to wheel Richmond's excess energy was unlawful discrimination because AEP and Indiana wheeled higher-priced electricity from other AEP affiliates. The court acknowledged that Richmond's claim of unlawful discrimination was theoretically valid, but found that Richmond had failed to prove its case. It noted that if Richmond had argued that the rates were unjustifiably discriminatory, or that Indiana's failure to use its transmission capability fully or to purchase less expensive electricity for wheeling resulted in unnecessarily high rates, a different case would be before the court.[206] The case thus does not in any way limit the Commission's authority to remedy undue discrimination.

In *Central Iowa Power Cooperative* v. *FERC*,[207] the FPC[208] reviewed the terms of the Mid-Continent Area Power Pool (MAPP) Agreement under its section 205 and 206 authority. The agreement contained two membership limitations. First, the agreement established two classes of membership, with one class being entitled to more privileges than the other. Second, the agreement excluded non-generating distribution systems from pool services. The FPC found the first limitation on membership—the two-class system—to be unduly discriminatory and not reasonably related to MAPP's objectives. The FPC conditioned approval of the agreement under section 206 on the removal of the unduly discriminatory provision. The FPC found that the second limitation, the exclusion of non-generating distribution systems, was not anticompetitive and did not render the agreement inconsistent with the public interest.

On appeal, the D.C. Circuit affirmed the FPC's decision. The court found that the FPC did have authority to order changes in the scope of the MAPP agreement, *if* the agreement was unjust, unreasonable, unduly discriminatory or preferential under section 206 of the FPA. The court stated:

> The Commission had authority, * * * under section 206 of the Act, * * * to order changes in the limited scope of the Agreement, including the addition of pool services, if, in the absence of such modifications, the Agreement presented ''any rule, regulation, practice or contract (that was) unjust, unreasonable, unduly discriminatory or preferential.''[209]

However, the court agreed with the FPC's conclusion that the limited scope of MAPP was not unjust, unreasonable, or unduly discriminatory. The court recognized that a pool was not invalid under section 206 merely because a more comprehensive arrangement was possible.

The D.C. Circuit upheld the Commission's refusal to eliminate the second limitation on membership by ordering MAPP participants to wheel to non-generating electric systems.[210] However, neither the Commission nor the court was presented with the argument that wheeling was necessary as a remedy for undue discrimination.

[199] *Id.* at 998.

[200] 410 U.S. 366 (1974).

[201] 410 U.S. at 375–76.

[202] *Id.* at 374–76.

[203] *See AGD*, 824 F.2d at 998.

[204] 574 F.2d 610 (D.C. Cir. 1978).

[205] *Id.* at 620.

[206] *Id.* at 623, nn.53 and 57.

[207] 606 F.2d 1156 (D.C. Cir. 1979).

[208] While *Central Iowa* was pending, certain of the functions of the FPC were transferred to the FERC under the DOE Organization Act. Accordingly, the FERC was substituted for the FPC as the respondent in the case.

[209] 606 F.2d at 1168.

[210] *Id.* at 1169; *see also* Municipalities of Groton v. FERC, 587 F.2d 1296 (D.C. Cir. 1978).

In *Florida Power & Light Company* v. *FERC (Florida),*[211] the Commission ordered Florida Power & Light Company (FP&L) to file a tariff setting forth FP&L's policy relating to the availability of transmission service.[212] FP&L objected to including such a policy statement in its tariff and argued that the filing of such a policy would convert FP&L into a common carrier by obligating it to offer service to all customers.[213] There was no finding that the action ordered was necessary to remedy undue discrimination.

The Fifth Circuit Court of Appeals agreed with FP&L that the mandatory filing of the policy statement would require FP&L to provide transmission service beyond its voluntary commitment because such a requirement would change its duties and liabilities.[214] The Commission order would impose common carrier status on FP&L, the court found.[215] The court noted that the Commission did not rely on a finding of anticompetitive behavior and therefore the court did not address the Commission's power to remedy antitrust violations.[216]

The *AGD* court explicitly rejected the claim that the above line of cases establishes that the Commission lacks authority to require non-discriminatory open access.[217] Opponents of the Commission's order argued in *AGD* that *Richmond* and *Florida, supra,* stand for the proposition that the Commission cannot indirectly do what it allegedly cannot do directly, that is, impose common carriage. The *AGD* court rejected these arguments, stating that the petitioners read the electric cases far too broadly:

> (n)either *Richmond* nor *Florida* comes anywhere near stating that the Commission is barred from imposing an open-access condition in all circumstances.[218]

The court noted that the *Florida* case had expressly left open the question of whether the Commission would be entitled to use an open access condition as a remedy for anticompetitive conduct, and that in *Richmond* the D.C. Circuit had said little more than that unwillingness to transmit for all could not be automatically deemed undue discrimination. The court also noted the *Central Iowa* case, *supra,* in which it had upheld a Commission order that found a power pooling agreement discriminatory on its face because the agreement gave one class of membership privileged status over another. The court stated that the *Central Iowa* case ''upholds the power of the Commission to subject approval of a set of voluntary transactions to a condition that providers open up the class of permissible users.'' [219] The court added that it refused to ''turn statutory construction upside down'' by letting Congress' failure to grant a general power of common carriage prevail over the affirmative grant of the specific power to eradicate undue discrimination.[220]

We conclude that *AGD*'s analysis of undue discrimination under sections 4 and 5 of the Natural Gas Act is equally applicable to an undue discrimination analysis under sections 205 and 206 of the FPA. The Commission and courts have long recognized that the NGA was patterned after the FPA and that the two statutes should be interpreted in the same manner.[221] Thus, we conclude that we have the authority to remedy undue discrimination and anticompetitive effects by requiring all public utilities that own, control or operate transmission facilities to file non-discriminatory open access transmission tariffs.

b. Section 211 of the Federal Power Act

In concluding that we must invoke our section 206 authority to remedy undue discrimination and anticompetitive effects in the electric industry, we have carefully considered the goals of Title VII of the Energy Policy Act, and whether section 211 of the FPA, by itself, is sufficient to remedy undue discrimination in public utility transmission services. Title VII of the Energy Policy Act, which amended section 211 of the FPA to give the Commission broader authority to order wheeling in the public interest on a case-by-case basis, reflects the intent of Congress to encourage competitive wholesale electric markets. Section 211 provides a means for wholesale power sellers and buyers to obtain transmission services necessary to compete in, or to reach, competitive markets, and is a valuable tool to encourage competitive markets. However, in amending section 211, Congress left unaltered the authorities and obligations of the Commission under sections 205 and 206 (similar to our authorities and obligations under sections 4 and 5 of the NGA) to remedy undue discrimination. In addition, as discussed below, reliance on section 211 alone in some circumstances can result in the perpetuation of, rather than the elimination of, undue discrimination and anticompetitive effects.

First, there are inherent delays in the procedures for obtaining service under section 211. However, for competitive reasons, many transactions must be negotiated relatively quickly. Many competitive opportunities will be lost by the time the Commission can issue a final order under section 211. Case-by-case section 211 proceedings are not a substitute for tariffs of general applicability that permit timely, non-discriminatory access on request.

Second, discrimination is inherent in the current industry environment in which some customers and sellers are served by open access systems, and others have to rely on negotiated bilateral arrangements or the mandatory section 211 process. The end result is discrimination in the ability to obtain transmission services, as well as in the quality and prices of the services. This national patchwork of open and closed transmission systems, with disparate terms and conditions of service, cannot be cured effectively through section 211.

The Commission believes that its actions under sections 205 and 206 will complement the section 211 procedures

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[211] 660 F.2d 668 (5th Cir. 1981), *cert. denied sub nom*. Fort Pierce Utilities Authority v. FERC, 459 U.S. 1156 (1983).

[212] FP&L provided transmission service when four conditions were met: (1) The specific potential seller and buyer were contractually identified; (2) the magnitude, time and duration of the transaction were specified prior to the commencement of the transmission; (3) it could be determined that the transmission capacity would be available for the term of the contract; and (4) the rate was sufficient to cover FP&L's costs.

[213] All utilities requesting wheeling services, subject to availability, would be entitled to receive transmission service under the filed terms. Any changes to a filed rate must be filed with the Commission. This is the so-called ''filed rate doctrine.'' *See* Northwestern Public Service Company v. Montana-Dakota Utilities Company, 181 F.2d 19, 22 (8th Cir. 1980), *aff'd,* 341 U.S. 246 (1951).

[214] Under the filed rate doctrine, a refusal to wheel would be unduly discriminatory under section 206 of the FPA. As the court acknowledged, a customer refused service could petition the Commission to find that FP&L's policy of availability was unduly discriminatory under section 206(a) of the FPA. The court said that in the absence of a tariff on file, a utility refused wheeling services would be unable to claim discrimination under section 206(a) of the FPA. 660 F.2d at 675 (expressing ''serious doubts that such a petition would be successful in the absence of a tariff'').

[215] *Id.* at 676.

[216] *Id.* at 678.

[217] The *AGD* court did not address New York State Electric & Gas Corporation v. FERC, 638 F.2d 388 (2d Cir. 1980), *cert. denied,* 454 U.S. 821 (1981) *(NYSEG),* presumably because that case did not concern whether the Commission could order wheeling as a remedy for undue discrimination.

[218] 824 F.2d at 999.

[219] *Id.* at 999.

[220] *Id.* at 1006.

[221] *See, e.g.,* FPC v. Sierra Pacific Power Company, 350 U.S. 348, 353 (1956); Arkansas Louisiana Gas Company v. Hall, 453 U.S. 571, 577 n.7 (1981); and Kentucky Utilities Company v. FERC, 760 F.2d 1321, 1325 n.6 (D.C. Cir. 1985). Section 206 of the FPA was recently revised and now differs from section 5 of the NGA, but not in a manner significant to our discussion here. *See* 16 U.S.C. 824e (b) and (c).

to achieve both the Energy Policy Act's goals of creating more competitive bulk power markets and lower rates for consumers and the Federal Power Act's explicit direction in section 205(b) that no public utility shall, with respect to any transmission in interstate commerce, grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage.

2. Response to Commenters Opposing Our Legal Authority

a. Authority to Order Open Access Tariffs

Comments

Initial Comments Supporting Commission Authority

A number of commenters support or state that they do not oppose the Commission's authority to order open access tariffs.[222] NIEP and CCEM explain that the *AGD* decision supports the Commission's action in this proceeding. ELCON asserts that the Commission's ''extensive treatment of the relevant case law demonstrating FERC's authority to remedy this discrimination is legally sound.'' UtiliCorp argues that section 211 supports, rather than undermines, the Commission's authority for the NOPR because it reflects Congress's intention to encourage more competitive bulk power markets.

Initial Comments Opposing Commission Authority

Other commenters assert that the Commission has improperly relied on sections 205 and 206 of the FPA to require open access.[223] They argue, for instance, that *Otter Tail* should be read as a broad constraint on the Commission's authority to order wheeling for *any* purpose and that the *AGD* decision does not undermine that holding or the cases following *Otter Tail*.[224] In support, some of these commenters discuss *Richmond Power & Light, New York State Electric & Gas Corporation,* and *Florida Power & Light Company,* the same cases discussed by the Commission in the NOPR.[225]

For example, EEI highlights the *AGD* court's discussion noting the difference between the legislative history of the NGA and that of the FPA, which the court stated was not as strong as that of the NGA. Moreover, EEI argues that the court found that section 7 of the NGA provided support for the Commission's actions in Order No. 436 and that such section 7 conditioning authority is lacking under the FPA. Allegheny notes that *AGD* did not overrule *Otter Tail.* Dayton P&L states that, in the gas case, the Commission was responding to voluntary filings by pipelines. It also says that before the NOPR, the Commission itself saw its authority as more limited. SCE&G points to differences between Commission jurisdiction over public utilities and gas pipelines and criticizes the Commission's alleged assumption that the circumstances involved in the gas and electric industries are virtually identical.

PA Com argues that the attempt to analogize to the NGA and the cases that refer to that Act is inconsistent with the technical and engineering realities of the electric transmission grid and that extensive comparisons between the natural gas industry and the electric industry are misleading.[226]

FL Com argues that, in relying on sections 205 and 206 to establish generic open access transmission tariffs for *all* public utilities, the Commission violates the court's decision in *Cajun Electric Power Cooperative* v. *FERC*, 28 F.3d 173 at 179 (D.C. Cir. 1994), where, FL Com argues, the court refused to allow the Commission to use a non-evidentiary ruling when there were material facts at issue.

Reply Comments

CCEM responds that EEI and others confuse the obligations of a common carrier with the duty of public utilities not to unduly discriminate. It says that *AGD* supports the Commission's authority because the legislative history of the FPA and the NGA are similar with respect to common carriage. According to CCEM, early versions of both statutes would have made the regulated industries operate as common carriers (citing *Otter Tail*, the legislative history of the FPA, the legislative history of the Public Utility Holding Company Act, and the legislative history of the Mineral Leasing Act), but that Congress chose not to impose the common carrier obligations.

CCEM also says that the duties the Commission imposed on the gas industry and those in the NOPR are not common carriage in any event. According to CCEM, a common carrier must carry all goods offered (citing *Am. Trucking Assoc.* v. *Atchison, T. & S.F. Ry. Co.*, 387 U.S. 397, 406 (1967)). Finally, CCEM cites *Stephenson* v. *Binford*, 287 U.S. 251, 265–66 (1932), where the Supreme Court held that obligations that are typical of common carriers can be imposed on contract motor carriers.

CCEM further disagrees with EEI's argument that the enactment of section 211 was a disavowal of any other Commission authority to order transmission.

ELCON also disagrees with EEI's claim that the Energy Policy Act undermines the Commission's pre-existing section 205 and 206 authority. It states that the savings clause in section 212(e) of the FPA, as amended, explicitly expresses Congress' intention not to undermine the Commission's pre-existing authority and that the legislative history contains nothing to suggest otherwise.

Similarly, in response to those who argue that section 211 is the only source of authority for the Commission to order transmission, NIEP argues that sections 211 and 212 serve purposes different from section 206. It says that the Commission's authority to order transmission in the ''public interest'' under sections 211 and 212 is not synonymous with its authority to order transmission as a remedy for undue discrimination under section 206; the two standards are complementary but distinct:

> Although broadly applicable, the Commission's ability to order wheeling under sections 211 and 212 is carefully limited by a number of procedural provisions. Foremost among these is the requirement that the wheeling may be ordered only upon a specific application for transmission services. FERC's authority to act in the public interest is thus confined to the individual case.
>
> By contrast, FERC's remedial powers under Section 206 can be exercised upon a finding of unjust, unreasonable or unduly discriminatory or preferential practices. Once that finding has been made, however, the form and substance of the remedy is left entirely to the FERC's discretion. If FERC deems it necessary, FERC may adopt generally applicable rules or practices as a countermeasure to discriminatory acts, including ordering utilities to file generally applicable transmission tariffs.[227]

NIEP also points out that the legislative history does not address the Commission's authority to order transmission as a remedy for undue discrimination. It challenges the

[222] NIEP, ELCON, CINergy, UtiliCorp, TAPS, SBA, Entergy, NY Energy Buyers, Sierra.

[223] *E.g.*, EEI, Atlantic City, Allegheny, VA Com, PA Com, Ohio Edison, Southern, Utilities For Improved Transition, Dayton P&L, SCE&G, Centerior, BG&E, Central Hudson, NY Com, Salt River, Carolina P&L, Union Electric, VEPCO, Utility Workers Union.

[224] EEI, VA Com, Union Electric.

[225] *E.g.*, EEI, VA Com, NY Com, PA Com, Salt River, Southern, Dayton P&L, Detroit Edison, BG&E.

[226] *See also* NY Com (NGA has no parallel provision to section 211 of the FPA), Salt River.

[227] NIEP Reply Comments at 8.

interpretation of the legislative history advanced by some commenters.[228]

Next, NIEP defends the Commission's proposed findings that there is generally undue discrimination in the provision of transmission service. It notes that when an agency acts on an industry-wide basis, the agency does not have to make a finding as to each particular case.

Finally, NIEP responds to those who argue that *AGD* is not on point. It notes that the *AGD* court discussed electric cases and emphasizes the court's statement that the NGA ''fairly bristles with concern for undue discrimination''—a statement that is equally true of the FPA.

TDU Systems responds to the argument that *Otter Tail* is a broad constraint on the Commission's authority to order transmission.[229] At issue in that case, it argues, was the reach of the Sherman Act, not of FPA sections 205 and 206. Similarly, it argues, the *Florida Power* case is not on point, and the court there specifically said that it was not deciding whether the Commission could have ordered wheeling as a remedy for anticompetitive activities. Moreover, TDU Systems asserts that EEI's use of a quote from a single Senator should carry no weight, since it is a well-established principle of statutory construction that such statements have little value. Finally, it points out that the *AGD* court itself did not view *Otter Tail* or other electric precedent as forbidding the Commission to order wheeling as a remedy for undue discrimination.

Entergy asserts that Congress's refusal to require utilities to provide transmission as common carriers or whenever it is in the public interest was merely a decision not to give the Commission general authority to order wheeling, without regard to undue discrimination. Thus, the *Otter Tail* language concerning the absence of a common carrier requirement does not demonstrate that Congress meant to limit the Commission's authority to remedy undue discrimination.

ELCON disputes EEI's reading of *NYSEG*, noting that the *NYSEG* court explicitly stated:

> Nor do we suggest that the Commission is powerless to review a wheeling agreement under section 206 without following the requirements of sections 211 and 212.[230])

TAPS discusses numerous cases, including the primary cases relied upon by the Commission, and disposes of *NYSEG* by stating that it is no longer good law, if it ever was.

Commission Conclusion

There can be no question that the Commission has the authority to remedy undue discrimination. Sections 205 and 206 of the FPA mandate that we ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. Under these sections, we must determine whether *any* rule, regulation, practice, or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and we must disapprove those contracts and practices that do not meet this standard. Our discretion is at its zenith in fashioning remedies for undue discrimination.[231]

Some commenters, however, challenge our authority to order industry-wide non-discriminatory open access as a remedy for the undue discrimination we have found in the industry. As summarized above, they essentially assert that we are prohibited by court precedent, the legislative history of the FPA, and sections 211 and 212 of the FPA from ordering wheeling as a remedy for undue discrimination. We disagree and conclude that we have the authority—indeed, a responsibility—to require non-discriminatory open access transmission as a remedy for undue discrimination.

AGD and Legislative History

The court decision in *Associated Gas Distributors* v. *FERC* provides powerful support for our ability to order industry-wide non-discriminatory open access transmission in the electric industry as a remedy for undue discrimination. As discussed in detail above, *AGD*, which is the only decision to have addressed the Commission's authority to remedy undue discrimination by requiring open access, upheld our authority under section 5 of the NGA (the parallel to section 206 of the FPA) to require open access in the natural gas industry. The rationale supplied by the *AGD* court applies equally to the FPA and our responsibility to eliminate undue discrimination in the electric industry.

Those who challenge the Commission's legal authority to remedy undue discrimination face the same difficulty that parties faced in seeking to overturn open access in the natural gas industry—they ''can point to no language in the (FPA) barring the Commission from imposing common carrier status on (public utilities), and certainly none barring it from imposing upon the (public utilities) a specific duty that happens to be a typical or even core component of such status.'' [232] Instead, as was unsuccessfully attempted in the *AGD* proceeding, they seek to overcome the statutory silence primarily by means of legislative history. However, as the *AGD* court explained, legislative history is not even relevant, because

> courts have no authority to enforce principles gleaned solely from legislative history that has no statutory reference point.[233]

Here, as the court found with respect to the NGA, the legislative history of the FPA ''provides strong support only for the point that Congress declined *itself* to impose *common carrier status* on (public utilities) * * * It affords weak—almost invisible—support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty.'' [234]

Commenters focus on the following statement in the *AGD* decision to support the argument that, because Congress did not expressly reject common carriage under the NGA, but did reject it under the FPA, a different outcome in this proceeding is required:

> we note that the legislative history of the two acts is, on this point, materially different. In its deliberations on the bill that ultimately emerged as the Federal Power Act, Congress considered and rejected a provision that would have ''empowered the Federal Power Commission to order wheeling if it found such action to be 'necessary or desirable in the public interest.' '' (citing *Otter Tail*) (quoting S. 1725, 74th Cong., 1st Sess.). The evidence as to the NGA (surveyed above) is less direct: it consists exclusively of various occasions on which Congress did not adopt proposals actually making the natural gas pipelines into common carriers.[235]

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[228] NIEP explains that

(W)hile much has been made of the Senate report accompanying S.2114, which subsequently became part of PURPA in 1978, that report does not illustrate an intent to limit FERC's authority to remedy undue discrimination under section 206. That report characterizes the Supreme Court's decision in *Otter Tail* as holding that ''the Federal Power Act leaves open a gap in its failure to assign the FPC general authority to order wheeling *in this situation* * * *.'' The ''situation'' to which the Report refers is not discrimination, however. Instead, the statement appears to make reference to circumstances in which general public interest concerns, such as reliability, efficiency and competition, are at stake. Thus, Senate Report 2114 is simply not a limitation on the Commission's remedial powers under Sections 206.

NIEP Reply Comments at 8–9 (citations omitted).

[229] See also Entergy.

[230] ELCON Initial Comments at 7 (quoting *NYSEG* at 403).

[231] *See, e.g.,*- Niagara Mohawk Power Corporation v. *FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967).

[232] *AGD*, 824 F.2d at 997.

[233] *Id.* (quoting *IBEW, Local No. 474* v. *NLRB*, 814 F.2d 697, 712 (D.C. Cir. 1987) (emphasis deleted by court from original)).

[234] *Id.* (emphasis added).

[235] *Id.* at 998–99.

The above statement, however, does not preclude the *AGD* court's decision on our broad authority to remedy undue discrimination in the gas industry from applying equally in the electric industry. Clearly, the court did not say that. As discussed below, we believe the statement focuses on a distinction in the legislative histories that is not meaningful.

First, whether or not a material difference exists in the respective legislative histories of the NGA and FPA, the fact remains that the crucial findings of the *AGD* court were that: (1) ''Congress declined *itself* to impose *common carrier* status'' (emphasis added) and (2) there is no ''support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty.'' [236] These findings apply equally to the FPA. Simply stated, statutory silence cannot be overcome by means of legislative history—even if the legislative history in fact indicated that Congress ''rejected'' legislative imposition of common carrier status under the FPA, but ''did not adopt'' it under the NGA. In either event, nothing in the statute or legislative history suggests that Congress concluded that the Commission could under no circumstances impose open access as a remedy to undue discrimination.

Moreover, the legislative history of the bills containing the FPA and the NGA, taken as a whole, suggests that the distinction drawn in *AGD* between the legislative histories of the NGA and the FPA is not meaningful. The legislation that was to become the FPA originally included provisions regulating both electric power and natural gas. As originally proposed, the legislation contained *identical* common carriage language for both public utilities and natural gas pipelines.

With respect to the FPA, the Supreme Court explained in *Otter Tail* that

(a)s originally conceived, Part II would have included a ''common carrier'' provision making it ''the duty of every public utility to * * * transmit energy for any person upon reasonable request * * *.'' In addition, it would have empowered the Federal Power Commission to order wheeling if it found such action to be ''necessary or desirable in the public interest.'' H.R. 5423, 74th Cong., 1st Sess.; S. 1725, 74th Cong. 1st Sess. These provisions were eliminated to preserve ''the voluntary action of the utilities.'' S.Rep. No. 621, 74th Cong., 1st Sess., 19.[237]

The language paraphrased by the Supreme Court was from Title II of the initial bill proposing the Public Utility Holding Company Act. The entire sections from which the paraphrased language came are as follows:

SEC. 202. (a) It shall be *the duty of every public utility to* furnish energy to, exchange energy with, and *transmit energy for any person upon reasonable request* therefor; and to furnish and maintain such services and facilities as shall promote the safety, comfort, and convenience of all its customers, employees, and the public, and shall be in all respects adequate, efficient, and reasonable.

* * *

SEC. 203. (b) Whenever the Commission after notice and opportunity for hearing finds such action *necessary or desirable in the public interest,* it may by order direct a public utility to make additions, extensions, repairs, or improvements to or changes in its facilities, to establish physical connection with the facilities of one or more other persons, to permit the use of its facilities by one or more other persons, or to utilize the facilities of, sell energy to, purchase energy from, transmit energy for, or exchange energy with, one or more other persons. Where any such order affects two or more persons, the Commission may prescribe the terms and conditions of the arrangement to be made between such persons, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.[238]

This initial bill proposing the Public Utility Holding Company Act also included a Title III that was intended to regulate the transmission and sale of natural gas. Sections 303(a) and 304 of Title III included the *identical* common carrier language paraphrased by the Supreme Court and included in sections 202(a) and 203(b) of Title II.[239] After further deliberations, Congress rejected the above-quoted language in Title II and eventually adopted a Title II that did not include any common carrier language. On the other hand, Title III (addressing regulation of natural gas) was not reported out of committee, but reemerged in the next year.[240] The bill that reemerged did not contain the common carrier language that was in the original Title III. However, as Congress had just debated the common carrier issue in enacting electric power regulation, it is not surprising that Congress did not engage in debating the very same issue in enacting natural gas regulation.

Because of the timing of the legislation involving the FPA and the NGA and the logical nexus between the two acts, we conclude that there is in fact no material difference as to this issue in the legislative histories of the two acts. Both initially included identical common carrier language, and the language was removed from both. As to both acts, Congress chose not to impose common carrier obligations on the electric or natural gas industries, but gave the Commission the authority and responsibility to eliminate undue discrimination in both industries. Consequently, as open access was found to be a proper remedy for undue discrimination in the natural gas industry, it is also a proper remedy for undue discrimination in the electric industry.

As the *AGD* court noted with respect to the Commission's powers and duties under the NGA, Congress explicitly gave the Commission the authority to eradicate undue discrimination under the FPA. That explicit power and duty provided by Congress cannot be invalidated solely on the ground that Congress chose not to impose statutory common carrier status on public utilities or did not explicitly authorize the Commission to do so.[241] As the *AGD* court explained, this would ''turn [] statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one.'' [242]

Other Case Law

A number of commenters argue that the Commission misinterpreted the other cases discussed in the NOPR with respect to our authority to order non-discriminatory open access transmission. We disagree. As demonstrated above, not one of the cases put forth by commenters holds that we cannot remedy undue discrimination by requiring public

[236] *Id.* at 997. We also note that the contract carriage obligation we are imposing is easily distinguished from the common carrier obligation Congress chose not to adopt. As discussed *infra,* the common carrier provisions rejected by Congress would have required transmission for ''any person'' upon reasonable request. This would have included retail purchasers.

[237] *Otter Tail,* 410 U.S. at 374.

[238] H.R. 5423, 74th Cong., 1st Sess., 32 (emphasis added).

[239] *Id.* at 44.

[240] In the debate on the subsequent bill to regulate natural gas, Congressman Cole explained:

Mr. Chairman, the House should realize that the measure we are dealing with today is of extreme importance, more so than the attendance and the time taken in the discussion would seem to indicate. It is the culmination of one of the most far-reaching, intensive studies of the Federal Trade Commission I assume that that Commission ever conducted, and last year found a place in not identical language but very similar in the Rayburn bill, the famous holding-company bill, as part 3 thereof. Our committee eliminated part 3, as members will recall, and saved it for a separate measure reported out as it was last year, which was not considered by the House, but is here today in improved form.

81 Cong. Rec. H6724 (daily ed. July 1, 1937).

[241] *AGD,* 824 F.2d at 998.

[242] *Id.*

utilities to provide non-discriminatory open access transmission.[243]

AGD is the *only* case in which a court specifically addressed our authority to order open access transmission as a remedy for undue discrimination. Its favorable finding with respect to our action under section 5 of the NGA directly supports our ordering non-discriminatory open access transmission under section 206 of the FPA.

Authority to Act by Rule

We disagree with those commenters that assert that we may find and remedy undue discrimination only through case-by-case adjudications and are prohibited from making a generic determination of undue discrimination through a rulemaking. First, there is no question that it is within our discretion whether we act through rule or through case-by-case adjudications.[244] The *AGD* court specifically rejected a similar argument that the Commission erred in requiring open access transportation tariffs without first finding that each individual pipeline's rates were unlawful. The *AGD* court held that ''(t)he Commission is not required to make individual findings if it exercises its § 5 authority by means of a generic rule.'' [245]

We have identified a fundamental generic problem in the electric industry: owners, controllers and operators of monopoly transmission facilities that also own power generation facilities have the incentive to engage, and have engaged, in unduly discriminatory practices in the provision of transmission services by denying to third parties transmission services that are comparable to the transmission services that they are providing, or are capable of providing, for their own power sales and purchases. These practices drive up the price of electricity and hurt consumers. Furthermore, the incentive to engage in such practices is increasing significantly as competitive pressures grow in the industry. It is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry-wide problem facing us.

b. Undue Discrimination/ Anticompetitive Effects

Initial Comments

A number of commenters allege that the Commission has failed to meet its burden of proving industry-wide discrimination.[246] They assert that the Commission has provided only a few unsubstantiated allegations of discrimination, which do not represent the current conditions in the electric industry, or that the Commission has not shown that all electric utilities have unduly discriminated. Some attack the NOPR's incorporation by reference of the unsubstantiated allegations of discrimination set forth in a petition for rulemaking filed on February 16, 1995 by the Coalition for a Competitive Electric Market (CCEM).[247]

EEI argues that the allegations of discrimination in the NOPR must be considered in light of the fact that: (1) All tariffs currently on file have been found by the Commission not to be discriminatory; (2) more than 30 utilities have voluntarily filed open access tariffs, which belies any assertion of widespread discrimination in the industry; and (3) transmission disputes are rare, with only 19 section 211 proceedings having been filed in the last three years.[248] EEI concludes that the Commission's allegations of discrimination do not rise to the level of ''extreme circumstances'' found by the court in the natural gas industry in *AGD*.

EEI adds that the Commission's proposal to act under section 206 is itself discriminatory because it applies only to public utilities and does not reach all transmission-owning utilities.[249] If reciprocity is designed to resolve this problem, EEI believes that reciprocity should also be ''effective for public utilities.'' Furthermore, EEI argues that the failure of a public utility to provide to others a service that it does not provide itself is not evidence of discrimination, and that inclusion of such a provision actually results in preferential treatment for transmission users.

NE Public Power District alleges that the NOPR does not contain a single reference to any actual discrimination or anticompetitive conduct by any publicly owned utility.

Salt River asserts that the Commission is required to consider all elements of an antitrust analysis before reaching a conclusion that market power exists in the transmission system and that we have failed to do so.[250] It concludes that the NOPR ''constitutes an attempt to legislate a remedy for an evil that has not been, and cannot be, lawfully found to exist on a wholesale basis among utilities that own and operate integrated generation and transmission systems.'' [251]

PA Com argues that the Commission's request for examples of discriminatory behavior is a ''tacit admission as to the paucity of evidence of discriminatory practices by transmission owning utilities.'' NY Com argues that the ''Commission's lack of a record basis for its proposed findings is legally suspect because courts in two cases have held that the Commission cannot proceed with open access transmission tariffs absent record findings of specific anticompetitive conduct.'' [252]

Finally, EEI claims that even if the Commission has proven its allegations of discrimination, we have failed to meet the requirements of section 206 of the FPA.[253] According to EEI, the Commission cannot find, without an adjudicatory hearing, that the rates on file are unlawful and order replacement rates.[254] The Commission's proposed procedure would unlawfully place the burden of justifying existing rates on the utilities.

Reply Comments

A number of commenters provide instances of discriminatory behavior they have faced over the years. NCMPA describes difficulties it has faced in dealing with CP&L, including a situation where CP&L allegedly impeded NCMPA's use of transmission access through CP&L's control of dispatching.[255]

AMP-Ohio alleges that Toledo Edison refused to transmit emergency power on a buy-sell basis to certain AMP-Ohio members even though Toledo Edison's system was not constrained. Instead, AMP-Ohio alleges, Toledo Edison bought the power and resold it to AMP-Ohio at a higher rate.

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[243] *See* FERC Stats. & Regs. at 33,053–56. We further note that the *AGD* court did not discuss the *NYSEG* decision at all. Indeed, the *NYSEG* case did not involve any allegations of undue discrimination and any discussion of section 206 by the court was dictum.

[244] *See, e.g.,* NLRB v. Bell Aerospace Company, 416 U.S. 267, 293 (1974) (citing SEC v. Chenery Corporation, 332 U.S. 194, 202–03 (1947). *See also* Heckler v. Campbell, 461 U.S. 458, 467 (1983) (even where enabling statute requires a hearing to be held, agency may rely on its rulemaking authority); Panhandle Eastern Pipeline Company v. FERC, 907 F.2d 185, 187–88 (D.C. Cir. 1990). Under section 403 of the DOE Act, 42 U.S.C. 7173, the Commission is authorized at its discretion to initiate rulemaking proceedings.

[245] *AGD,* 824 F.2d at 1008.

[246] *E.g.,* EEI, Ohio Edison, PA Com, BG&E, NY Com, Minnesota P&L, Carolina P&L.

[247] *E.g.,* EEI, BG&E.

[248] *See also* Ohio Edison.

[249] *See also* SCE&G.

[250] Salt River Initial Comments at 5–6 (referencing an attached legal memorandum of Donald A. Kaplan).

[251] Salt River Initial Comments at 6.

[252] NY Com Initial Comments at 16–18 (discussing *FPL* and *Cajun*).

[253] *See also* Southern.

[254] *See also* Southern.

[255] We note that CP&L raised legal objections to our authority to implement this rule.

APPA challenges EEI's claim that there is no substantial evidence of undue discrimination in transmission. It suggests that nineteen instances of transmission disputes being filed since the Energy Policy Act was enacted is ample evidence of undue discrimination. Moreover, according to APPA, reported abuses are only the tip of the iceberg.

CCEM responds to the argument raised by EEI and others that there is no showing of extreme circumstances of discrimination in the electric industry such as the *AGD* court noted in the gas industry. It says that these circumstances are present and gives numerous examples; it does not identify the specific utilities because ''it is the experience of * * * (our) members that nearly all transmission owners retaliate * * *'' against anyone who complains. Moreover, in answer to EEI's statement that transmission disputes are rare, CCEM states that since most of the competition is in the short-term market, it has not been worthwhile to file complaints. The examples provided by CCEM include: (1) Refusal by a California public utility to offer firm service; (2) refusal by control area utilities in Texas to offer ancillary services to a power marketer, with the result that one of the utilities won the bid, even though it did not have the lowest price; (3) non-utilities in ERCOT being unable to compete to meet short-term requests for economy energy because they were required to schedule by noon of the preceding day, while utilities did not subject themselves to such a scheduling requirement; (4) power pool or control area information requirements, particularly in the northwest part of WSPP, that force non-utilities to reveal commercially sensitive information; the transportation operator has then revealed the information to its own or its affiliate's sales arm, which ''steals'' the deal; (5) a northeast power pool that refused to wheel out even though capacity was available on the grounds that sending power out of the pool would drive up prices in the pool (hoarding); (6) a power marketer that asked a utility to provide transmission, whereupon the utility bought up certain transmission capacity necessary for the marketer to reach its buyer, thus blocking the path—this was possible because the utility was able to locate the purchaser based on commercially sensitive information the marketer had to give the utility when the marketer asked for transmission; (7) a common contracting practice among utilities restricting the use of interconnections to themselves, particularly in the Southwest Power Pool, MAPP, and MAIN; (8) utilities overstating the cost of improvements (gold-plating) and thus discouraging service. CCEM also responds to each of EEI's criticisms of CCEM's examples of undue discrimination submitted in its February 16, 1995 petition and argues that its examples of undue discrimination are unrebutted.

Brownsville asserts that

> while PUB [Brownsville] must pay multiple distance-based and pancaked transmission rates to engage in transactions with the non-ERCOT universe, El Paso Electric would have *received* transmission payments from its merger partners while gaining *free* transmission access to buy and sell within ERCOT. CSW presently walls other ERCOT utilities off from participation in the Western Systems Power Pool, while its ERCOT subsidiaries, CPL and WTU, share in the benefits of their non-ERCOT affiliates' WSPP memberships via the preferential terms of the CSW Operating Agreement. CSW treats its own inter-affiliate central dispatch as having a higher priority than third-party economy energy transactions, with the result that CPL not infrequently crowds PUB out of the economy market.[256]

Wisconsin Municipals states that its members have been fighting transmission battles for years and sets forth five examples of the sort of difficulties it has experienced in attempting to obtain transmission rights. For example, it explains that Wisconsin public utilities have resisted an effort by the state commission to achieve comparability of use of transmission. Wisconsin Municipals also explains a situation where ''if WPPI continued to purchase its power from WPSC, it would pay WPSC $843,840 annually for transmission service: if it purchases power off system from WP&L (one of WPSC's competitors), WPPI would pay WPSC $1,774,224 for transmission service to the exact same load.''

TAPS sets forth additional examples of undue discrimination, including refusals to wheel even in the face of Nuclear Regulatory Commission (NRC) nuclear license conditions requiring wheeling, and Northeast Utilities' refusal to provide transmission to a QF even though it had indicated to the Commission that it would provide such transmission in order to obtain Commission approval of its proposed merger with Public Service Company of New Hampshire.

NIEP sets forth ten examples of undue discrimination that its members have experienced in seeking access to transmission service at reasonable terms and conditions.

[256] Brownsville Reply Comments at 2–3 (emphasis in original).

Some commenters challenge these claims of undue discrimination. For example, Carolina P&L responds to NCMPA #1's example of obstruction by Duke in accommodating energy sales from the jointly owned Catawba Plant. Carolina P&L explains that NCMPA #1's proposal ''would require Duke to provide its own generation resources on behalf of NCMPA #1 in order to support a bulk power sale when NCMPA #1's own resource capacity and energy are not sufficient for the sale.'' Carolina P&L argues that this is backstanding that goes beyond the scope of any ancillary service the Commission has proposed and would be entirely inappropriate ''to compel the Transmission Provider to sell power to its Transmission Customer for resale on the bulk power market.''

Duke also responds to NCMPA #1's claim of discrimination and asserts that NCMPA #1's claim is not relevant to the NOPR proceeding, but is a specific contractual claim that should be pursued pursuant to the terms of its contract.

Commission Conclusion

We conclude that unduly discriminatory and anticompetitive practices exist today in the electric industry and, more importantly, that such practices will increase as competitive pressures continue to grow in the industry, unless the Commission acts now to prevent such practices.[257] It is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices. As the *AGD* court stated: ''Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [258]

We set forth examples in the NOPR of undue discrimination that we believe are occurring in the electric industry and invited commenters to identify any discrimination that they may have experienced. In response, commenters

[257] While many public utilities have filed some form of open access tariff (often in response to our proposed rule), we believe that many of the remaining utilities will not voluntarily open their systems absent a final rule. *See also* note 266.

[258] *AGD*, 824 F.2d at 1008.

presented numerous additional examples of undue discrimination, which are summarized above, and we set forth below further examples of undue discrimination that have been raised in cases before the Commission.

Many of the examples of discriminatory behavior that have been brought to our attention do not name the specific utilities involved, and many are allegations that are not proven. However, we do not believe that this undermines our finding of unduly discriminatory practices by transmission owners and controllers. We believe that it is only natural that potential transmission customers with an interest in participating in electric markets will be reluctant to name names for fear of being shut out of those markets. CCEM, which identified a wide array of discriminatory behavior its members have experienced, explained that

(w)e do not identify the specific utilities in each example because it is the experience of CCEM members that nearly all transmission owners retaliate by cutting off all communications with anyone that challenges or complains about the rates, terms or conditions at which the owner offers access to its system. Inasmuch as most of the competitive commerce in electric power today is in short-term markets, it is typically not worth the effort of CCEM members or other transmission-dependent entities to file a complaint with the Commission's enforcement staff or in the courts in connection with a transmission owner's discriminatory practices. The deal is lost well before a complaint can be processed and ruled upon.[259]

Other examples of discriminatory behavior have also been raised in proceedings before the Commission. As we explained in detail in the NOPR, transmission-owning utilities have discriminated against others seeking transmission access in a variety of ways, most often subtly and indirectly.[260] For example, delaying tactics have been used to frustrate access. The history of Pacific Gas and Electric Company's (PG&E) attempt to avoid its commitments made to the California owners of the California-Oregon Transmission Project (COTP) is a prime example. The owners had originally planned the COTP to have its southern terminus at the Midway station with Southern California Edison. PG&E convinced them to terminate the project instead at PG&E's Tesla station and indicated that PG&E would provide transmission service the rest of the way south to Midway. PG&E promised this service in 1989 (in Principles). PG&E spent the next four years filing substitute provisions for what it had promised in the Principles.[261] Additional allegations of discriminatory behavior are set forth in Appendix C, which includes allegations made under oath in proceedings at the Commission and allegations made in pleadings and other documents before the Commission.

In addition, to date, the Commission has received 28 section 211 transmission requests.[262] Applicants submit section 211 transmission requests when the transmission provider refuses to provide the requested transmission service. For example, American Municipal Power-Ohio, Inc. (AMP-Ohio) requested Ohio Edison Company (Ohio Edison) to establish additional delivery points to certain of AMP-Ohio's members and to permit the addition of delivery points in the future upon AMP-Ohio's request. Ohio Edison refused AMP-Ohio's request, claiming that it was not a proper request under section 211 because it already provided wholesale transmission to the municipal utilities at issue. In a proposed order, the Commission disagreed with Ohio Edison and ordered Ohio Edison to provide the requested additional delivery points and to entertain future requests by AMP-Ohio for specific delivery points.[263]

Many of the examples of discriminatory actions we are seeing in the electric industry are similar to those we saw in the gas industry. Given our experience, we find that these examples of discriminatory actions are credible and well-founded. Thus, we conclude that there is more than sufficient reason to believe that transmission monopolists currently engage in unduly discriminatory practices, and that they will continue to engage in unduly discriminatory practices, unless we fashion a remedy to eliminate their ability and incentive to do so. In light of the competitive changes occurring in today's electric industry, we believe that the only effective remedy is non-discriminatory open access transmission, including functional unbundling and OASIS requirements, and that it is within our statutory authority to order that remedy.

Further, we disagree with the argument that we are limited to applying a traditional antitrust analysis in determining whether market power exists in the transmission system. While we must take antitrust concerns into consideration in exercising our responsibilities under the FPA, we are not an antitrust court, and our responsibilities are not those of the Department of Justice.[264] We have analyzed the incentives and practices of monopoly transmission owners and controllers in light of the statutory standards and directives of the FPA and, based on our findings, have properly concluded that there is a generic problem that must be remedied.

The Commission also recognizes, as some commenters suggest, that we have, in the past, permitted utilities to file tariffs containing restrictions on transmission service that we are now finding to be unduly discriminatory in this rule and that we found unduly discriminatory in cases since our decision in *AEP*. However, it is entirely appropriate, and indeed necessary, that our application of the FPA's undue discrimination standard evolve over time and adapt to the changing circumstances in the industry. Our prior willingness to tolerate the use of monopoly power over transmission to maintain and aggregate the utility's market power over generation occurred in the context of an industry structured largely as vertically integrated regulated monopolies that supplied all facets of utility service—power supply, transmission, and distribution—as a single monopoly service. Competition generally was not meaningfully available as a means to discipline prices and consumer interests were best served by improving efficiencies of the integrated utilities, subject to cost-based regulation.

Today, the circumstances of the industry are radically different. As explained in detail in Section III, a series of significant economic, regulatory, and technical changes in the power industry has introduced the promise of competitively priced power supplies. The profile of electric power suppliers has expanded to include not just the power supply arms of traditional utilities, but also independent power suppliers, affiliated utility power suppliers selling into territories of other franchise utilities,

[259] CCEM Initial Comments at 18–19. *See also* NIEP Reply Comments at 13 n.31.

[260] FERC Stats. & Regs. at 33,072.

[261] *See* Pacific Gas and Electric Company, 65 FERC ¶ 61,312 at 62,428–30 and n.22, *remanded on other grounds,* Pacific Gas & Electric Company v. FERC, No. 94–70037 (9th Cir. June 23, 1994)(unpublished opinion), *order on remand,* 69 FERC 61,006 (1994).

[262] A list of section 211 applications and the status of each is attached as Appendix A.

[263] American Municipal Power-Ohio, Inc. v. Ohio Edison Company, 74 FERC ¶ 61,086 (1996).

[264] *See, e.g.,* Gulf States Utilities Company v. FPC, 411 U.S. 747, 758–60 (1973); FPC v. Conway Corporation, 426 U.S. 271, 279 (1976); Northern Natural Gas Company v. FPC, 399 F.2d 953, 960 (D.C. Cir. 1968).

and power marketers.[265] This offers the promise of an increasingly competitive commodity market in electric power, in which significant benefits to consumers can be achieved. In the context of an emerging competitive market in generation, discriminatory practices that once did not constitute *undue* discrimination must be reviewed to determine whether they are being used to prevent the benefits of competition in generation from being achieved. Here we find conclusively that they are, and use our remedial authority to ensure that they can no longer occur.[266]

c. Section 211

Comments

Various commenters contend that the enactment of section 211 in essence either removed any authority the Commission might have had under sections 205 and 206 or demonstrates that Congress did not believe the Commission could order wheeling under those provisions.

These commenters assert that the legislative history of the FPA indicates that Congress specifically rejected giving the Commission authority to order wheeling under any circumstances.[267] They further contend that the legislative history of section 211 demonstrates that Congress viewed the authority it granted in section 211 as a strictly limited and entirely new authority for the Commission.[268] Specifically, EEI states that the legislative history of the Energy Policy Act confirms that the expanded authority provided under section 211 was not intended to grant the Commission blanket authority to order wheeling, even as a remedy for anticompetitive conduct. Similarly, Utilities For Improved Transition argues that the legislative history shows that Congress specifically intended to preclude the Commission from ordering tariffs of general applicability under any circumstances. In addition, EEI points to testimony provided by a Commission staff witness before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce in which EEI claims that ''she suggested that an affirmative statement that the Commission had the power to require wheeling on its own motion should be included, possibly in section 211.'' EEI maintains that such suggestion was rejected by Congress in favor of allowing the Commission to order wheeling only upon application.

Detroit Edison, asserting that *Cajun* stands for the proposition that the agency must follow Congressionally mandated procedures, claims that the Commission can order transmission only after going through the procedures of section 211. Detroit Edison also argues that the Commission should incorporate into the final rule the various safeguards of section 211, such as the requirement that the utility receive prior notice, the requirement that transmission service be in the public interest, and the requirement that existing service not be displaced. FL Com further asserts that it was Congressional intent in the Energy Policy Act for wheeling to be ordered on a case-by-case basis pursuant to section 211.[269]

EEI argues that the enactment of section 211 eliminated any authority the Commission had under sections 205 and 206 to order wheeling as a remedy for undue discrimination. It alleges that the Commission failed to discuss the *NYSEG* case concerning the relationship between section 211 and sections 205 and 206 in any meaningful way. According to EEI, the *NYSEG* court concluded that section 211 ''was the only appropriate vehicle under which the Commission could order NYSEG to wheel power for the municipality.'' [270]

EEI further resorts to canons of statutory construction to conclude that ''section 211 must be given effect as the more specific provision and must be interpreted to limit the scope of sections 205 and 206.'' [271] In addition, EEI asserts that ''Congress had an opportunity to reject the *NYSEG* court's interpretation of the scope of sections 205, 206 and 211, but instead amended section 211 in a manner that is consistent with the view that mandatory wheeling is to be governed exclusively by section 211.'' Dayton P&L raises similar arguments. It notes the savings provision in section 212(e), but says that Congress ''would have been more specific if it understood that the Commission already had the authority to order wheeling under FPA sections 205 and 206. * * *'' [272]

Associated EC argues that the NOPR appears to exceed the Commission's authority in that it proposes that ''wholesale *buyers* and sellers have 'equal access to the transmission grid.' '' It asserts that ''Section 211(a), however, makes mandatory transmission service available only to '[a]ny electric utility, Federal power marketing agency or any other person generating electric energy for sale for resale.' '' [273]

NE Public Power District argues that sections 211 and 212 of the FPA appear clearly to contemplate a case-by-case approach.[274] NE Public Power District adds that if the Commission believes sections 211 and 212 are inconsistent with the public interest, it can ask Congress to modify those provisions. Allegheny adds that the Commission can order wheeling only under sections 211 and 212 on a company-specific basis and can use sections 205 and 206 only to evaluate the reasonableness of terms and conditions of voluntarily filed agreements or tariffs by public utilities.

Utilities For Improved Transition also claims that sections 211 and 212 override any authority the Commission might have had under sections 205 and

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[265] We note that there are now 14 power marketers that are affiliated with public utilities.

[266] We take note of EEI's comments that, at the time of the comments, 30 utilities had filed open access tariffs. They argue, therefore, that the rule is unnecessary. Since their comment was filed, the number of utilities filing some form of an open access tariff has risen to 106. However, while some of these tariffs are based on the NOPR pro forma tariffs, many of these tariffs fall significantly short of the tariff requirements of both the NOPR and this Rule. Even if the tariffs met these requirements, the Rule is still needed to complete the task of eliminating undue discrimination by all public utilities and assuring, to the extent possible, a nationwide open access transmission grid. Indeed, a number of these tariffs were filed for the purposes of securing authority to market power *competitively*. This underscores markedly our fundamental conclusion that prior practices of using monopoly power over transmission to preserve market power over electricity sales has no place in today's industry and must be eliminated to get the benefits of competition to the customers we are required to protect under the FPA.

[267] *E.g.,* EEI, VA Com, Ohio Edison Southern, Utilities For Improved Transition, BG&E.

[268] *See also* NM Com.

[269] *See also* Salt River. Moreover, FL Com states that the Commission should modify its hearing process to better accommodate state PUC participation by: (1) Holding hearings in the affected state; (2) teleconferencing; (3) making free transcripts available to states; and (4) substantially deferring to a state when the state commission has held a hearing on an issue in the case.

[270] EEI quoted the following language from *NYSEG*:

Nor do we suggest that the Commission is powerless to review a wheeling agreement under section 206 without following the requirements of sections 211 and 212. If, after a hearing as required by section 206, the Commission determines that a particular rate, charge or condition is unreasonable, it can order a modification. But where, as here, the modification amounts to an order requiring wheeling, it must be preceded also by determination in accordance with sections 211 and 212. Simply put, we will not allow the Commission to do indirectly without compliance with the statutory prerequisites, what it could not do directly without such compliance. (citing *Richmond Power & Light*).

[271] *See also* VA Com.

[272] *See also* Carolina P&L.

[273] This argument is puzzling. First, section 211 does not control to whom access must be provided under sections 205 and 206. However, even if it did, Associated EC appears to misconstrue eligibility under section 211. An electric utility as defined in the FPA is any person or State agency (including any municipality) which sells electric energy. The definition does not say that electric energy must be re-sold at wholesale. Thus, an electric utility could be a wholesale *buyer* of transmission used to transmit energy for sale at either wholesale or retail.

[274] *See also* Allegheny.

206 to order industry-wide open access. It cites the savings clause in section 212(e) of the FPA as limiting the Commission's authority to order transmission.[275] Utilities For Improved Transition argues at some length that the NOPR does not meet the procedural and substantive standards of sections 211 and 212. It goes on to cite various passages from the legislative history of the Energy Policy Act as supporting the view that Congress intended to eliminate the Commission's authority to order industry-wide open access as a remedy for undue discrimination. According to Utilities For Improved Transition, these passages ''unmistakably show a clear legislative intent to preclude the mandatory transmission that the Commission attempts here * * *.''

Commission Conclusion

We disagree with those commenters that argue that the Energy Policy Act either eliminates our authority under section 206 to remedy undue discrimination by requiring non-discriminatory open access transmission or demonstrates that we never had any such authority. Nothing in sections 211 and 212 or in the legislative history of these sections indicates that Congress intended to eliminate the Commission's other, broader authorities under the FPA. Indeed, section 212(e) specifically provides:

SAVINGS PROVISIONS.—(1) No provision of section 210, 211, 214, or this section shall be treated as requiring any person to utilize the authority of any such section in lieu of any other authority of law. Except as provided in section 210, 211, 214, or this section, *such sections shall not be construed as limiting or impairing any authority of the Commission under any other provision of law*.[276]

Utilities For Improved Transition's argument that the ''Except as provided'' clause limits or impairs the Commission's authority to order transmission service under sections 205 and 206 would make the savings provision meaningless. Moreover, such a reading would be entirely at odds with the underlying purposes of the Energy Policy Act. It would be ironic indeed to interpret the Energy Policy Act as eliminating our long-standing, broad authority to remedy undue discrimination, given the pro-competitive purpose of the statute.

The legislative history also provides no support for the arguments that sections 211 and 212 remove or prove the non-existence of the Commission's authority to remedy undue discrimination by requiring non-discriminatory open access transmission. In fact, virtually every bit of legislative history raised by commenters opposing the NOPR consists of various statements by Senator Wallop, an opponent of expanding transmission access under sections 211 and 212.[277] Such legislative history provides no insight into the meaning of a statute and is given little or no weight by the courts.[278]

The only other legislative history that commenters put forth is the testimony of a Commission staff witness, in 1992 hearings before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce. According to EEI, the witness indicated that an affirmative statement that the Commission could require wheeling on its own motion ''would be needed [in the Energy Policy Act] if Congress intends for the Commission to be able to deal with transmission on its own motion and thereby go further than simply dealing with industry proposals.'' EEI claims that this statement demonstrates that the expanded authority in the Energy Policy Act ''was not intended to grant the Commission blanket authority to order wheeling, even as a remedy for anticompetitive conduct.''

EEI's argument is misleading and disingenuous. It takes the witness's statements out of context, ignoring attendant testimony that ''there are strong legal arguments that the Commission's obligation to protect against undue discrimination carries with it the authority to impose transmission requirements as a remedy for undue preference or discrimination,'' and the extensive legal argument, included in her testimony, in favor of that position—an argument that closely parallels the legal argument the Commission is relying on in this proceeding.[279] Indeed, in the face of such explicit testimony from the staff of the agency required to implement the statute, had Congress intended to limit the Commission's remedial authority under section 206 when it amended section 211, we believe it would have explicitly done so in the language of the statute itself, or at least have indicated its intent to do so in the Conference Report on the Energy Policy Act.[280]

C. Comparability

1. Eligibility to Receive Non-Discriminatory Open Access Transmission

In the NOPR, the Commission proposed to define who is eligible to receive service under a non-discriminatory open access tariff as follows:

A non-discriminatory open-access tariff must be available to any entity that can request transmission services under section 211.[281]

The Commission further explained that ''[u]nder section 211, any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale may request transmission services under section 211.'' [282]

[275] It states that

Section 212(e), however, provides that Sections 211 and 212 limit or impair the Commission's authority under ''other provisions of law'' (a phrase including, obviously, Sections 205 and 206). On the face of the statute—we say again for emphasis: *on the face of the statute*—the Commission therefore does not have the authority to order transmission service outside the provisions of Sections 211 and 212.

Utilities For Improved Transition Initial Comments at 51 (emphasis in original).

[276] 16 U.S.C 824k (emphasis added).

[277] In discussing the electricity provisions of the Energy Policy Act, Senator Wallop declared:

It would be a mistake to take the presence of transmission access provisions in the Conference Report as a sign of change in position on my part or that of the Senate. I would have strongly preferred PUHCA reform without any transmission access provisions, as was the Senate position. However, in order to obtain the very significant benefits of PUHCA reform contained in the Senate bill, it was necessary to accept some of the House transmission access provisions.

138 Cong. Rec. S17615 (daily ed. October 8, 1992).

[278] *See, e.g.,* Shell Oil Company v. Iowa Department of Revenue, 488 U.S. 19, 29 (1988) (*Shell*). In *Shell,* the Court declared:

This Court does not usually accord much weight to the statements of a bill's opponents. ''[T]he fears and doubts of the opposition are no authoritative guide to the construction of legislation.'' *Gulf Offshore Co.* v. *Mobil Oil Corp.,* 453 U.S. 473, 483 (1981) (quoting *Schwegmann Bros.* v. *Calvert Distillers Corp.,* 341 U.S. 384, 394 (1951).

See also Sutherland Statutory Construction § 48.16 at 366.

[279] Hearings on H.R. 1301, H.R. 1543, and H.R. 2224 before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, 102d Cong., 1st Sess. (May 1,2 and June 26, 1991), Statement of Cynthia A. Marlette, Associate General Counsel, Federal Energy Regulatory Commission, Report No. 102–60 at 60 and 61–70. *See also id.* at 106 (''I believe that we have substantial authority under the existing case law to mandate access where necessary to remedy anticompetitive effects.'').

[280] At the time Congress enacted amendments to FPA section 211, it was well aware that the Commission had unexplored authorities under sections 205 and 206 of the FPA to compel wheeling. The only explicit limitations it chose to impose on the Commission's wheeling authorities were those contained in sections 212(g) and (h), which provide that no order ''under this Act'' may be inconsistent with any State law governing retail marketing areas of electric utilities (section 212(g)), or be conditioned upon or require the transmission of electric energy directly to an ultimate consumer (section 212(h)).

[281] FERC Stats. & Regs. ¶ 32,514 at 33,083 (footnote omitted).

[282] *Id.* at 33,083 n.195.

Comments

PSNM believes that the NOPR properly defined customer eligibility. NIEP, on the other hand, believes that the proposed definition is too limited. It argues that the Commission should require public utilities to make transmission service available to all entities engaged in wholesale purchases or sales of power, not just to those ''generating'' power. Utility Working Group requests that the Commission clarify that eligibility is dependent not only on being the type of entity set forth in section 211, but on meeting the requirements of section 212(h) (Prohibition on Mandatory Retail Wheeling and Sham Wholesale Transactions) as well.[283]

We also received several comments related to the applicability of the rule to foreign entities. Canada states that the requirements for comparability and reciprocity should be implemented in a flexible manner to permit Canadian utilities to have fair and competitive access in the U.S. electricity market. Maritime requests that the Commission require Canadian utilities who wish to participate in the U.S. market to offer other utilities the same privileges they receive in the United States. Southwestern argues that transmission *to* a foreign country is in interstate commerce and that a utility should therefore accommodate this type of transmission request under its open access tariff. El Paso argues that the Commission does not have the authority to condition access to foreign countries, but states that if the Commission nevertheless exercises such authority it should do so on a case-by-case basis. Destec asserts that

> the posturing of Ontario Hydro before U.S. regulators pleading for open access and non-discriminatory transmission treatment—even for extra-territorial entities, should be met with a strong reply that such provisions should also be afforded transmission dependent entities on the Canadian side of the border. Ontario Hydro's aggressive pursuit of U.S. market opportunities while simultaneously blocking competitors through the control of their transmission assets can not be ignored.

Commission Conclusion

In the Final Rule pro forma tariff the Commission has modified the definition of ''eligible customer'' to address concerns that in some respects the NOPR definition was too limited and in other respects it was too broad. This includes amended language to clarify that any entity engaged in wholesale purchases or sales of energy, not just those ''generating'' electric power, is eligible. It also includes clarification that entities that would violate section 212(h) of the FPA (prohibition on Commission-mandated wheeling directly to an ultimate consumer and sham wholesale transactions) are not eligible. The language also has been modified to provide that foreign entities that otherwise meet the eligibility criteria may obtain transmission services. Further, it has been modified to provide for service to retail customers in circumstances that do not violate FPA section 212(h).[284]

Persons that would be eligible section 211 applicants also would be eligible under the open access tariffs. Section 211 applicants may be any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale.

Section 3(22) of the FPA, as amended by the Energy Policy Act, defines ''electric utility'' to mean

> any person or State agency (including any municipality) which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency.

Thus, as we have previously noted, municipal utilities are electric utilities simply by the terms of the statute.[285] In addition, we have also found that cooperatives and marketers are electric utilities as defined in the FPA.[286] Other entities that fall within the definition include IOUs, IPPs, APPs, and QFs that sell electric energy.

We do not believe that entities that engage solely in brokering should be eligible. Such brokers do not take title to electricity and therefore do not engage in the sale of electric energy; nor do they generate electric energy for sale for resale.[287] Although such brokers are not eligible under the tariffs, they will be able to arrange deals because they will have access to the OASIS of all public utilities and will be able to solicit information from the relevant transmission service providers under the terms of the applicable tariffs.

We clarify that foreign entities that otherwise meet the eligibility criteria must be eligible to receive service under the non-discriminatory open access transmission tariffs.[288] We are making this determination pursuant to our authority under section 206 of the FPA to remedy undue discrimination. As we explained in the NOPR, market power through the control of transmission can be used discriminatorily to block competition. Customers in the United States should not be denied access to cheaper supplies of electric energy, whether such electric energy is from a domestic source or a foreign source. By making non-discriminatory access available to foreign entities that otherwise meet the eligibility criteria, we are assuring that customers in the United States have access to as many potential suppliers as possible. This should result in increased competition and lead to customers paying the lowest possible prices for their electric energy needs. To the extent that such an entity obtains access, however, we emphasize that it would be subject to all of the terms and conditions of the applicable open access tariff, including the *requirement* that it provide reciprocal service.

Finally, we have reconsidered our NOPR position that would have limited eligibility to wholesale transmission customers. As we explained in the NOPR, the Commission's jurisdiction extends to *all* unbundled transmission in interstate commerce by public utilities. It is irrelevant to the Commission's jurisdiction whether the customer receiving the unbundled transmission service in interstate commerce is a wholesale or retail customer. Thus, if a public utility voluntarily offers unbundled retail access in interstate commerce or a state retail access program results in unbundled retail access in interstate commerce by a public utility, the affected retail customer *must* obtain its unbundled transmission service under a non-discriminatory transmission tariff on file with the Commission. Though the Commission may approve a separate retail transmission tariff when some variation is necessary or appropriate to meet local concerns,[289] we generally see no reason why retail transmission tariffs necessarily must be different from wholesale transmission tariffs. For that reason, we anticipate that in many

[283] Section 212(h) (Prohibition on Mandatory Retail Wheeling and Sham Wholesale Transactions).

[284] We emphasize that *any* transmission customer must follow prudent utility practices so as to assure reliability.

[285] New Reporting Requirement Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibility Under the Energy Policy Act of 1992, and conforming and Other Changes to Form No. FERC–714, Order No. 558–A, 65 FERC ¶ 61,324 at 62,451 n.12 (1993).

[286] Order No. 558, FERC Stats. & Regs. ¶ 30,980 at 30,895–96, *reh'g denied,* 65 FERC ¶ 61,324 (1993) (cooperatives are electric utilities); *AES Power, Inc.,* 69 FERC ¶ 61,345 at 62,297 (1995) (power marketer is an electric utility, *i.e.,* a person ''which sells electric energy'').

[287] *See, e.g.,* Citizens Energy Corporation, 35 FERC ¶ 61,198 at 61,452–53 (1986).

[288] In making this determination, we are not deciding whether these entities are eligible entities under section 211(a) of the FPA.

[289] *See* Section IV.I.

circumstances the same open access tariff that serves wholesale customers will be equally appropriate for retail transmission customers. Therefore, unless the Commission has specifically permitted a separate retail tariff, eligible customers under the Final Rule pro forma tariff must include unbundled retail customers.[290] We discuss this further in Section IV.I.

While the rates, terms, and conditions of all unbundled transmission service will be subject to a Commission-authorized tariff, we will, in appropriate circumstances, give deference to state recommendations regarding rates, terms, and conditions for retail transmission service or regarding the proper transmission cost allocation to be used between retail and wholesale customers when state recommendations are consistent with our open access policies. This is also discussed further in Section IV.I.

Moreover, we are mindful of the fact that we are precluded under section 212(h) from ordering or conditioning an order on a requirement to provide wheeling directly to an ultimate consumer or sham wholesale wheeling. We therefore clarify that our decision to eliminate the wholesale customer eligibility requirement does not constitute a requirement that a utility provide retail transmission service. Rather, we make clear that if a utility chooses, or a state lawfully requires, unbundled retail transmission service, such service should occur under this tariff unless we specifically approve other terms.

2. Service That Must be Provided by Transmission Provider

In the NOPR, the Commission proposed that a public utility must offer to provide any point-to-point or network transmission service whether or not the utility provides itself that service:

> The Commission therefore proposes that all public utilities must offer both firm and non-firm point-to-point transmission service and firm network transmission service on a non-discriminatory open access basis in accord with the proposed rule and the attached appendix tariffs. The Commission believes that a utility's tariff must offer to provide any point-to-point transmission service and network transmission service that customers need, even though the utility may not provide itself the specific service requested.[291]

Comments

EGA and SMUD agree that a transmission owner should offer any transmission service it is able to provide, even if it does not use the service itself.

Public Generating Pool, an association of consumer-owned electric utilities, appears concerned that the Commission may interpret comparability broadly to require a utility to offer the same service provided by another utility or to offer service generally available in a region. Thus, it recommends that a third party seeking more service than a utility provides itself be required to resort to the section 211 process.

Commission Conclusion

Initially, we note that, with the possible exception of small utilities (which may qualify for a waiver, *see infra*), we have seen no evidence that public utilities are incapable of reasonably providing the services required in the Final Rule pro forma tariff. Nor have we seen evidence that utilities able to provide these services to themselves are choosing to forego such services. In short, we are not convinced that there is an appreciable difference, if any, among the services required in the pro forma tariff, the services utilities are able to provide, and the services they actually provide themselves.

To the extent these services do differ, however, we explicitly adopt the proposal set forth in the NOPR. Thus, a public utility must offer transmission services that it is reasonably capable of providing, not just those services that it is currently providing to itself or others. Because a public utility that is reasonably capable of providing transmission services may provide itself such services at any time it finds those services desirable, it is irrelevant that it may not be using or providing that service today. Moreover, a public utility must offer these transmission services whether or not other utilities may be able to offer the same services and whether or not such services are generally available in the region (waiver of these requirements for small utilities is discussed in Section IV.K.2.).[292] However, if a customer seeks a customized service not offered in an open access tariff, a customer may, barring successful negotiation for such service, file a section 211 application.

3. Who Must Provide Non-Discriminatory Open Access Transmission

In the NOPR, the Commission proposed to require all "public utilities" owning and/or controlling facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs.[293] We explained that we could not require all "transmitting utilities" to file open access tariffs under sections 205 and 206 because we do not have jurisdiction over non-public utilities under these sections.

Comments

Several commenters argue that the open access requirement must be applied to non-jurisdictional utilities that own interstate transmission facilities.[294] Power Marketing Association recognizes that this raises difficult legal issues and suggests that the Commission support legislation to expand the Commission's authority over non-jurisdictional utilities. Minnesota P&L argues that if the requirement is not applied to all entities that own transmission, jurisdictional and non-jurisdictional entities owning joint transmission facilities will be competitively disadvantaged due to unequal pricing. Union Electric argues that unless the requirement is extended to the 56 non-jurisdictional entities operating control areas, discrimination in the wholesale power markets will increase.

A number of municipal commenters assert that the NOPR overlooks transmission assets jointly owned by jurisdictional and non-jurisdictional utilities.[295] They argue that agreements regarding use of these assets often contain provisions prohibiting third-party power transfers. They further argue that such provisions should be nullified, and the joint owners should be required to develop equitable methodologies to allocate wheeling revenues among themselves.

Several cooperatives urge the Commission to clarify that contracts among their constituent cooperatives are not subject to any unbundling of existing contracts.

Commission Conclusion

Our authority under sections 205 and 206 of the FPA permits us to require only public utilities to file open access tariffs as a remedy for undue discrimination. We have no authority

[290] The Commission has no authority to order retail transmission directly to an ultimate consumer or to order "sham" wholesale transmission. *See* FPA section 212(h). However, if such access occurs voluntarily or as a result of a state program, the rates, terms, and conditions of the access are within our exclusive jurisdiction if the service is provided by a public utility.

[291] FERC Stats. & Regs. ¶ 32,514 at 33,079.

[292] Requirements for ancillary services are discussed in Section IV.D.

[293] FERC Stats. & Regs. ¶ 32,514 at 33,049.

[294] *E.g.*, Minnesota P&L, Power Marketing Association.

[295] *E.g.*, Springfield.

under those sections of the FPA to require non-public utilities to file tariffs with the Commission.

However, we are concerned that if non-public utilities do not provide access, there will remain a patchwork of ''open'' and ''closed'' transmission systems and the potential for distortions in wholesale bulk power markets. We believe that certain mechanisms exist that will help to alleviate these problems.

First, as we explained in the NOPR, broad application of section 211 will provide wider access to bulk power markets.[296] Under section 211, eligible entities may seek transmission service from ''transmitting utilities,'' which section 3(23) of the FPA defines as ''any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.'' We believe that section 211 provides us with authority to require the same *quality* of transmission service as sections 205 and 206, though the procedural path is more cumbersome. Thus, section 211 provides access to transmission systems owned or operated by non-public utilities.[297]

Second, as we explained in the NOPR, our reciprocity requirement is designed to provide the widest possible use of the nationwide transmission grid:

> The purpose of this provision is to ensure that a public utility offering transmission access to others can obtain similar service from its transmission customers. It is important that public utilities that are required to have on file tariffs be able to obtain service from transmitting utilities that are not public utilities, such as municipal power authorities or the federal power marketing administrations that receive transmission service under a public utility's tariff.[298]

Finally, again as we explained in the NOPR, the formation of RTGs should speed the development of competitive markets and involve more non-public utilities in the provision of non-discriminatory open access transmission.[299] In approving RTGs, our policy has been to require all members, whether or not they are public utilities, to offer comparable transmission services at least to other members.

We recognize that these solutions are not perfect. However, given the difficulties inherent in the statutory scheme, we believe they will go a long way toward effectuating transmission access by non-public utilities.

One further issue involving non-public utilities concerns jointly owned transmission facilities. We will not allow public utilities that jointly own interstate transmission facilities with non-jurisdictional entities to escape the requirements of open access. We will require each public utility that owns interstate transmission facilities jointly with a non-jurisdictional entity to offer service over its share of the joint facilities, even if the joint ownership contract prohibits service to third parties. We urge such public utilities to seek mutually agreeable revisions to their agreements to permit third-party access over all, or at least their share, of the facilities. For those joint ownership arrangements that include restrictions on the usage of jointly owned transmission facilities by third parties, we will require the public utilities, in a section 206 compliance filing, to file with the Commission, by December 31, 1996, a proposed revision (mutually agreeable or unilateral) to its contract with the non-jurisdictional owner(s). This revision must be designed at a minimum to permit third parties to use the public utility's share of the joint facilities in accordance with this Rule and must provide for any needed cost allocation procedures between the public utility and the non-jurisdictional owner(s).

4. Reservation of Transmission Capacity by Transmission Customers

In the NOPR, the Commission set forth the information that a requester of transmission service would have to submit with a service request. We recognized that there may have to be a limit, for competitive reasons, on the information required, but also recognized the need to assure that no customer would reserve scarce capacity and then hold it without using it.[300] To avoid forcing transmission customers to reveal unnecessary details of their purchase or sales transactions, the Commission discussed several less restrictive options: (1) Allow the transmission provider to use or sell the capacity while it is unused, (2) have a pool that clears the short-term market, and (3) require the customer to begin using the capacity within some specified period or lose its reservation rights. The Commission requested comments on these and other possible approaches.

Comments

Unused or Unneeded Transmission Capacity

Many commenters recommend a use-it-or-lose-it rule (*i.e.*, a transmission customer must use its reserved transmission capacity or lose its rights to that capacity).[301] Several commenters also recommend a number of restrictions on capacity reservations to reduce incentives to hoard or to cherry-pick (request to reserve firm capacity only during peak hours of peak seasons) existing transmission capacity. These include: (1) Allow requesters to reserve a place in the queue with a right of first refusal over later competing requests; (2) impose a take-or-pay charge on reservations and deny reservation holders the right to revenue sharing if they do not schedule or assign their rights; (3) limit the time period for reservations; (4) limit how far in advance reservations may be made for both non-firm and firm services; (5) maintain a price cap on the resale of transmission; (6) require multi-year reservations to be for sequential periods; and (7) require a nonrefundable fee for advance reservations of service.[302] Southwestern suggests that transmission tariffs include a provision that prevents transmission customers and the transmission provider from reserving and tying up firm transmission capacity for speculative wholesale transactions.[303]

On the other hand, PSNM believes that a use-it-or-lose-it approach is inappropriate because any prudent utility that has reserved capacity would seek to sell the service it is not using so as to recover some portion of its fixed costs. Wisconsin P&L argues that a use-it-or-lose-it approach would not work, would be difficult to administer, and may be anticompetitive.[304] Central Illinois Public Service asserts that a reservation holder has little incentive to hoard capacity because other customers can use the capacity on a non-firm basis during times when a reservation holder does not schedule power. It warns that

[296] FERC Stats. & Regs. ¶ 32,514 at 33,050 and 33,092–93.

[297] As discussed in the NOPR, sections 211 and 212 require that applicants specify only rates, terms, and conditions of service, not specify transactions. Thus, applicants can file requests for tariffs to accommodate future, currently unspecified transactions, similar to the open access tariffs required by this Rule.

[298] FERC Stats. & Regs. ¶ 32,514 at 33,089.

[299] *Id.* at 33,095.

[300] *Id.* at 33,090.

[301] *E.g.*, Consumers Power, Northern States Power, PacifiCorp, Oklahoma G&E, Allegheny Power, ELCON, Public Service Co of CO.

[302] *E.g.*, Northern States Power, VEPCO, Utilities For Improved Transition, PacifiCorp, Arizona Public Service, Dairyland, Montaup, Illinois Power, South Carolina E&G, Florida Power Corp, KU.

[303] *See also* NRECA.

[304] Wisconsin P&L notes, however, that a possible exception exists where a user could block the efficient transfer of power and then market its own power at a premium price.

giving the transmission operator the ability to schedule unused capacity may result in undue influence and the exercise of market power. CA Energy Com maintains that, while reassignment would help prevent hoarding, it would not assure efficient use of the full transmission network.

Use of Pooling Arrangements To Prevent Improper Reservations

Allegheny Power contends that a pooling arrangement could provide an incentive to hoarders to release capacity during a shortage. It suggests that capacity could be auctioned within a pool of available capacity. However, it acknowledges that an auction would be tantamount to allowing the network owner to sell transmission service at unregulated rates.

PacifiCorp does not believe that a pooling arrangement would prevent capacity hoarding unless nonsequential reservations are prohibited. ELCON contends that a use-it-or-lose-it rule would be fairer and more effective than pooling.

Commission Conclusion

Upon further consideration, we conclude that firm transmission customers, including network customers, should not lose their rights to firm capacity simply because they do not use that capacity for certain periods of time. Firm transmission customers that have reserved capacity and paid a reservation charge generally do not use the entire amount of reserved capacity at all times. This does not mean, however, that they must permanently return the unused amount to the utility. In the absence of evidence of hoarding or other anticompetitive practices, we will not limit the amount of transmission capacity that a customer may reserve. Firm transmission customers are in the best position to know the levels of electric energy they will be transmitting and the level of flexibility they need in carrying out their transmission activities. Indeed, when they are not using their reserved capacity, firm transmission customers remain obligated to pay the utility a reservation charge that covers all of the utility's fixed costs associated with the reserved capacity.[305]

Moreover, the possibility that a customer will reserve capacity and then hold it without using or reassigning it is mitigated because the utility is free to schedule and sell any unscheduled firm point-to-point transmission capacity on a non-firm basis to any entity eligible to receive such service under the utility's tariff. We also note that it is in the economic self interest of reservation holders to make available unused capacity to the market.[306]

We recognize that situations could arise in which a customer unlawfully withholds capacity. That is, a transmission customer could retain capacity in a way that could have an anticompetitive effect. For example, a transmission customer may reserve certain capacity simply to prevent everyone else from using it and to make its own generation the only alternative available to the market. However, as described above, we believe that the incentives are such that parties are more likely to release unneeded capacity and that a generic remedy is therefore unnecessary. Any substantial allegations that indicate that a transmission customer is withholding scarce capacity in a way that has an anticompetitive effect would be addressed under section 206. If we found such allegations to be true, we could order the customer to return the capacity reservation right to the transmission operator. This approach should allay concerns that a customer may reserve scarce capacity and not use it, without forcing customers to demonstrate need or to reveal details of individual transactions.

5. Reservation of Transmission Capacity for Future Use by Utility

Comments

EEI and many IOUs argue that native load and network transmission customers should have first priority to existing capacity for their reasonably forecasted load requirements because that capacity was constructed to provide service to them and was paid for by them.[307] EEI contends that such priority ensures equity and comparability based on past and future cost responsibility for the system. Similarly, Florida Power Corp and PECO contend that third-party customers should not be allowed to use transmission capacity that native load customers would grow into within a reasonable planning horizon.

Other commenters disagree, asserting that available transmission capacity must be determined in the same manner for all customers and that utilities should not be permitted to reserve capacity for their own uses.[308] NIEP argues that utilities should not be permitted to lock up available transmission capacity over valuable transmission paths and then require transmission requesters to pay for the cost of incremental transmission upgrades. This would let the utility avoid incremental transmission charges on its system. Oklahoma G&E argues that existing available transmission capacity should be made available until it is needed for native load growth. Utilicorp states that transmission owners should not be permitted to set aside capacity for sales or purchases of economy energy. CCEM argues that the centerpiece of comparability is that all transmission customers, including the merchant operations of the transmission owner, take service from available capacity pursuant to the same tariffs. CCEM adds that allowing utilities to reserve capacity based on forecasted retail and network loads creates an incentive for them to over-forecast their load to the detriment of all others. NRECA suggests that the need to maintain reliability should not perpetuate transmission providers' preferential treatment of their own transactions. It also recommends that, during periods when facilities are constrained, access be allocated based on a combination of past actual use and planned future use.

Commission Conclusion

We conclude that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon. However, any capacity that a public utility reserves for future growth, but is not currently needed, must be posted on the OASIS and made available to others through the capacity reassignment requirements, until such time as it is actually needed and used.

In response to arguments raised by several commenters that existing requirements customers should have future rights to existing capacity beyond the terms of their contracts because of their historical use, as discussed previously, we believe existing customers should have a right of first refusal to capacity they previously used, if they are willing to match the rate offered by another potential customer, up to the transmission provider's maximum filed transmission rate at that time, and to accept a contract term at

[305] A reservation charge would assure that the utility fully recovers its fixed costs associated with the transmission customer's reserved transmission capacity.

[306] *See* Section IV.C.6.

[307] *E.g.*, NYPP, Public Service E&G, Sierra Pacific Power, Ohio Edison. Sierra Pacific Power asserts that a utility should be permitted to retain capacity for native load use over the pertinent planning period. El Paso adds that the Commission should allow utilities the opportunity to reserve capacity for anticipated uses that, although not firm, are necessary to maintain reliability.

[308] *E.g.*, NIEP, CCEM, Conservation Law Foundation.

least as long as that offered by another potential customer.[309]

6. Capacity Reassignment

In the NOPR, the Commission proposed that a tariff must explicitly permit reassignment of firm service entitlements.[310] We explained that reassignment of capacity rights could have a number of benefits: (1) Helping transmission users manage financial risk, (2) reducing transmission providers' market power by enabling transmission customers to compete with them, and (3) improving capacity allocation when capacity is constrained and some market participants value capacity more than current capacity holders. We requested comments on whether the current price cap on resale should be modified or eliminated and whether the transmission services described in the NOPR are suitable for reassignment.

Comments

General

Many commenters favor capacity reassignment and the development of secondary markets.[311] However, WP&L notes that reassignments should not be permitted over constrained interfaces if the source or destination of power changes, and LA DWP opposes unrestricted reassignment because it could cause tax-exempt financing problems for many public power utilities.

Many IOUs argue that the same terms and conditions of service applied to IOUs should be applied to resellers of transmission services.[312] Arizona Public Service, however, asserts that all unused transmission rights should not be assignable, but should be made available to others in a manner consistent with the contract supporting the rights. It argues that a network user experiencing an off-system network shutdown should be required during the outage to make available to others the path from the point that the power enters the system to its load. It also contends that firm transmission customers should be required to post their unused rights on an EBB or RIN.

Several commenters oppose mandatory reassignment of firm capacity rights.[313] NEPCO declares that if a customer is willing to pay for its reserved capacity, it should not be forced to reassign unused capacity. Nebraska Public Power District believes that mandatory reassignment could cause problems for publicly-owned utilities. It further asserts that in the gas industry the Commission did not allow the unregulated reassignment regime it proposes for the electric industry.

SoCal Edison argues that when a transmission customer resells transmission capacity, it should not be released from its contractual obligation to the transmission provider. It notes that under traditional contract law, a party to a contract cannot escape its obligations by delegating them to another.

Price Caps

Most commenters addressing this issue support retaining the existing price cap on reassignments or resales.[314] Generally, these commenters believe that the price cap is necessary to prevent customers from speculating or hoarding capacity in anticipation of its value increasing. Public Service Co of CO believes that allowing assignments of capacity at prices greater than cost could prevent a transmission provider from offering firm capacity for legitimate long-term transactions. TDU Systems states that a cap should remain until the secondary market in the relevant geographic market has been shown to be competitive. PA Com states that turning available capacity into a spot market would tie up capacity that might otherwise be used on a day-to-day basis and for emergencies. Still other commenters argue that customers should not be allowed to sell the capacity for more than the transmitting utility could charge.[315] Allegheny argues that any rule that allows resale of transmission capacity at a higher price than the transmission provider can achieve is ''patently illogical and probably illegal.'' Several utilities, including Allegheny and CSW, contend that if resellers can market transmission services at market rates, then transmission owners must be given the same opportunity.

Duquesne and United Illuminating argue that the price cap should be modified so that third parties are allowed to resell capacity at the higher of embedded costs or opportunity costs.[316] Duquesne notes that such a provision would be comparable to the option transmitting utilities now have and would be economically efficient because it would encourage the firm capacity owner with the lowest opportunity cost to resell its capacity.

A few commenters argue that the price cap should be eliminated.[317] IL Com claims that capacity will be made available to the entity that values it most and that an uncapped resale market cannot lead to more market power because an efficient secondary market cannot be monopolized. Con Ed agrees that if the secondary market is competitive, all entities should be allowed to sell at market-based rates.[318] CT DPUC argues that there should not be a price cap; instead, it would prefer that those holding transmission rights not be allowed to withhold use of any portion of their reserved transmission capacity in the actual moment-by-moment operation of the grid.

Creditworthiness Standards

Of those commenting on the appropriate creditworthiness standards for replacement customers (assignees), all favor allowing the transmission provider to use reasonable credit procedures to assure that the replacement customer is financially sound.[319] NYSEG suggests that, at a minimum, the same creditworthiness criteria should be applied to the replacement customer as are applied to the original customer. Oglethorpe recommends that the assignee be required to commit to comply with all customer obligations and to pay for any additional costs resulting from the assignment.

Liability for Payment

Commenters split on whether the original customer or the replacement customer should be liable to the transmitting utility for payment for the service. One group of commenters believes that the original customer should remain liable for all costs and for the performance of all obligations.[320] Another group of commenters believes that the original customer should be relieved of financial responsibility, at least under certain circumstances.[321] For

[309] *See* Section IV.A.5.

[310] FERC Stats. & Regs. ¶ 32,514 at 33,088.

[311] *E.g.*, PacifiCorp, DOJ, NIEP, ELCON, United Illuminating, DOD, WP&L, FTC. OK Com and FL Com favor reassignment of capacity, but express concerns that reliability not be affected.

[312] *E.g.*, Northern States Power.

[313] *E.g.*, NEPCO, Nebraska Public Power District.

[314] *E.g.*, NRECA, Montana Power, PacifiCorp, NYSEG, PA Com, Idaho, Public Service Co of CO, FPC, Entergy, TDU Systems, Duke, Cajun, CVPSC, Oglethorpe, Minnesota DPS. FL Com argues that the price of reassignment should be capped at the contract selling price. WP&L argues that the price cap should be raised to the maximum rate allowed in the tariff under which the user purchased the original service.

[315] *See also* Minnesota DPS.

[316] *See also* Midwest Commissions, SMUD, CCEM.

[317] *E.g.*, IL Com, NEPCO, Consumers, American Wind.

[318] If the market is not competitive, however, Con Ed maintains that the cap should be retained for all entities.

[319] *E.g.*, PacifiCorp, NYSEG, Oglethorpe.

[320] *E.g.*, Oglethorpe, NSP.

[321] *E.g.*, NYSEG, Entergy, TDU Systems, Turlock, American Wind.

example, NYSEG asserts that the original customer should be relieved of its obligations upon the execution of a new service agreement between the new customer and the provider. TDU Systems contends that the original customer should be relieved of future liability where the replacement customer meets the transmission provider's creditworthiness standards. Entergy argues that the original customer should remain liable until all obligations are fulfilled.

Commission Conclusion

After reviewing the comments, we conclude that a public utility's tariff must explicitly permit the voluntary reassignment of all or part of a holder's firm transmission capacity rights [322] to any eligible customer.[323] Reassignment may be on a temporary or permanent basis, and must be subject to the conditions and requirements discussed below.

Allowing holders of firm transmission capacity rights to reassign capacity will: (1) Help them manage the financial risks associated with their long-term transmission commitments, (2) reduce the market power of transmission providers by enabling customers to compete, and (3) foster efficient capacity allocation. We offer below a number of clarifications and further explanations in response to concerns raised by commenters.

(1) Reassignable Transmission Services

We conclude that point-to-point transmission service, because it sets forth clearly defined capacity rights, should be reassignable. As for network transmission service, we conclude that there are no specific capacity rights associated with such service, and thus, network transmission service is not reassignable.

(2) Terms and Conditions of Reassignments

a. General

In effecting a reassignment, the assignor does not have to return its capacity entitlement to the original transmission provider, but may deal directly with an assignee without involvement of the transmission provider. However, an assignee must meet the eligibility standard established by this Rule and must comply with the reliability criteria of the original transmission provider. Any such transaction must be posted on the transmission provider's OASIS within a reasonable time after its effective date. Alternatively, the assignor may, if it wishes, request the transmission provider to effect a reassignment on its behalf.[324] In such a situation, the transmission provider must immediately post the available capacity on its OASIS. The transmission provider must assure that any revenues associated with the reassignment are credited to the assignor.[325]

b. Contractual Obligations

Assignors and assignees may contract directly with each other, but the assignor will remain obligated to the transmission provider. This obligation extends to any penalties or other charges incurred by the assignee in its use of the reassigned capacity. The assignee will be liable solely to the assignor, and should it not meet its obligations, the assignor may cancel the assignment under their contract.

If the transmission provider and the original customer mutually agree, we will permit alternatives to the above approach. For example, the transmission provider could agree to relieve the original customer of payment liability for the term of the reassignment and permit the assignee to pay the provider directly.

In the case of a permanent reassignment, the transmission provider should not unreasonably refuse to release the assignor from liability if the assignee meets the transmission provider's creditworthiness requirements as set forth in its tariff and agrees to pay the price the assignor is obligated to pay the transmission provider.

c. Price Cap

We conclude that the rate for any capacity reassignment must be capped by the highest of: (1) The original transmission rate charged to the purchaser (assignor), (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment, or (3) the assignor's own opportunity costs capped at the cost of expansion (Price Cap). We remain convinced that we cannot lift the Price Cap and permit reassignments at market-based rates. Based upon the information available in this proceeding, we are unable to determine that the market for reassigned capacity is sufficiently competitive so that assignors will not be able to exert market power. Thus, we will not permit an assignor to reassign capacity at a rate in excess of the Price Cap. Assignees must agree, in contracting with the assignor, that the firm transmission capacity they will use is subject to the Price Cap.

7. Information Provided to Transmission Customers Comments

Many commenters argue that in an open access, competitive environment, confidential and proprietary information should not be made publicly available through a RIN.[326]

Several utilities assert that the existing reporting requirements are sufficient to support the comparability requirements of the proposed rule, with some modifications.[327] They note that the Commission's audit authority and complaint process will help enforce comparability requirements.[328] Central Illinois Public Service states that, with the availability of pricing and transaction information through the RIN, no further reporting requirements are necessary. IL Com states that additional reporting should be required only if clear evidence emerges of discriminatory use of the transmission system. Dominion Resources adds that users have no need for utility planning information and data on generator status and that disclosure of such information would place owners at a competitive disadvantage. VEPCO opposes the disclosure of any commercially sensitive information to marketers, including the utility's power marketing employees.

On the other hand, several commenters argue that the information submitted by public utilities may not be adequate. For example, APPA argues that the Commission should scrutinize closely cost functionalization by utilities to assure that plant in service is properly booked. Others recommend that the Commission put in place a monthly pass-through of transmission-related operating income for all classes of customers receiving firm transmission service, rather than rely on the current practice of reducing test year

[322] The transmission provider has the same rights as any other potential assignee to obtain capacity that is posted on an OASIS or to negotiate with the assignor for any capacity the assignor seeks to assign.

[323] The public utility's tariff shall not preclude an assignor from including a right of recall in its agreement with an assignee.

[324] The assignor may also request the transmission provider to provide the billing and payment services for the reassignment. The parties would negotiate terms for such an arrangement, including a fee for the transmission provider. If an assignor is a public utility, it will have to have on file with the Commission a rate schedule governing reassigned capacity.

[325] Any expenses that the public utility incurs in carrying out the capacity assignment program would simply be included in its cost of service.

[326] Similar arguments with respect to the information that public utilities must provide to the Commission in standard reports (*e.g.*, Form No. 1) are addressed later in this Final Rule.

[327] *E.g.*, PacifiCorp, NYSEG, NSP.

[328] *See also* PA Com.

cost of service by revenues booked to Accounts 456 and 447. Industrial Energy Applications recommends that utilities be required to file quarterly reports with the Commission that detail the transmission services and the pricing of their off-system power supply transactions, as an incentive to comply with the Commission's rule.

Commission Conclusion

We conclude that all necessary transmission information, as detailed in the OASIS final rule, must be posted on an OASIS. With respect to generation information, we will require, consistent with the OASIS final rule, that information needed to verify opportunity/redispatch costs be provided, on request, to the transmission customer charged. We will not require this information, or any other generation information,[329] to be posted on an OASIS.[330]

8. Consequences of Functional Unbundling

a. Distribution Function

The NOPR proposed functional unbundling of wholesale generation and wholesale transmission so that the public utility as a wholesale seller could not gain an undue advantage from its transmission ownership. We did not propose to further unbundle the retail transmission and distribution functions from the wholesale transmission function.

Comments

A number of commenters assert that utilities should be required to unbundle—either functionally or corporately—the distribution function from the transmission function. ELCON argues that unbundling distribution would help delineate state and Federal jurisdiction, facilitate the establishment of transmission pricing, avoid cross-subsidization, and prepare for the customer choice (retail wheeling) programs that will be implemented by states in the future. It contends that functional distinctions between wholesale and retail service should be minimized.[331]

Other commenters, however, oppose establishing a separate distribution function. DOD asserts that the Commission can address any problems that arise by enforcing the terms of open access tariffs and that the Commission should not intrude into state ratemaking.[332]

Various state commissions question the workability and desirability of a functional test to determine the dividing line between retail transmission and local distribution.[333] CA Com recommends that, to avoid jurisdictional uncertainty surrounding functional unbundling, the Commission adopt a functional test for local distribution. Under this test, vertically integrated utilities that chose to unbundle into separate operating companies, including a local distribution company that sells only at retail, could establish a workable bright line between state and Federal authority without engaging in the arduous task of differentiating transmission from distribution.

Certain IOUs echo the jurisdictional concerns raised by the state commissions.[334] They believe that the unbundling of the distribution function would create significant jurisdictional problems. Pacificorp also argues that unbundling of the distribution function would create significant jurisdictional conflict with respect to cost allocation.

Commission Conclusion

We conclude that the additional step of functionally unbundling the distribution function from the transmission function is not necessary at this time to ensure non-discriminatory open access transmission. Our approach to assuring such open access has two broad requirements: (1) Functional unbundling of transmission and generation (which includes separately stated rates for generation, transmission, and ancillary services, and a requirement that a transmission provider take service under its own tariff), except for bundled retail service and (2) an OASIS with standards of conduct. We believe that additional requirements are not needed now. We further address in Section IV.I the concerns raised regarding our proposed tests to distinguish transmission and local distribution.

b. Retail Transmission Service

Comments

The majority of commenters addressing this issue believe that unbundling retail service is unnecessary to establish a competitive market and to achieve non-discriminatory open access transmission.[335] For example, PSNM argues that the Commission is not as well situated as are state regulators to oversee and supervise local reliability issues for retail customers. Central Illinois Public Service argues that due to the nature of transmission facilities and operations, it is not possible for the transmission provider to discriminate between the provision of wholesale and retail firm service. Several IOUs further contend that because the Commission is specifically precluded from mandating retail wheeling and has no authority over bundled retail service, the Commission cannot require retail service to be provided.[336]

In contrast, some commenters argue that functional unbundling must apply to all transmission service in interstate commerce provided by public utilities, including the transmission component of bundled retail sales.[337] They believe that this is necessary to achieve comparability. For example, CCEM asserts that if the distribution function is not unbundled, the result will be service under two separate arrangements—an explicit wholesale transmission tariff filed at the Commission and an implicit retail transmission tariff governed by a state regulatory body. According to CCEM, failure to unbundle retail transmission will allow transmitting utilities to manipulate how they characterize and account for their own uses of transmission. ABATE contends that the Commission, for efficiency reasons, should encourage states to permit retail access. It asserts that the Commission must adopt a policy that signals to states how rates, terms, and conditions of retail service will be established; once a state sets such parameters, the Commission should review them.

Commission Conclusion

Although the unbundling of retail transmission and generation, as well as wholesale transmission and generation, would be helpful in achieving comparability, we do not believe it is necessary. In addition, it raises numerous difficult jurisdictional issues

[329] The prices of some ancillary services, which are posted on the OASIS, are based on generation costs, however.

[330] Because the Commission establishes many generation and all transmission rates on a cost basis, the Commission also will continue to need the information that it collects in Form No. 1 and other standard forms from public utilities to assure that the rates are just and reasonable. As we explain later in this Final Rule, the information provided in those forms is public information that is available to any transmission customer. However, because of the competitive changes occurring in the electric industry, we recognize that there may be a need to reexamine the information we collect from public utilities through the Form No. 1.

[331] *See also* Environmental Action, Missouri Basin MPA, Texaco, EGA, AEC & SMEPA.

[332] *See also* TDU Systems, Public Service Co. of CO.

[333] *E.g.*, NARUC, AZ Com, CT DPUC, OK Com, FL Com, NC Com, NM Com.

[334] *E.g.*, Com Ed, Citizens Utilities, PacifiCorp.

[335] *E,g,*, Allegheny Power, PacifiCorp, MidAmerican, PECO, Public Service Co. of CO, Com Ed, NARUC, NRRI, MN DPS, ND Com, FL Com.

[336] *E.g.*, Allegheny Power.

[337] *E.g.*, CCEM, ABATE.

that we believe are more appropriately considered when the Commission reviews unbundled retail transmission tariffs that may come before us in the context of a state retail wheeling program. The Commission therefore reaffirms its decision to require the unbundling only of wholesale transmission from generation.[338]

c. Transmission Provider

1. Taking Service Under the Tariff

In the NOPR, we explained that a public utility must take transmission services for all of its new wholesale sales and purchases of energy under the same tariff of general applicability under which others take service.[339]

Comments

A number of commenters argue that utilities should be required to take all of the transmission for their own use under their tariff.[340] CCEM asserts that a transmission owner should have to schedule, at arm's length, its retail transmission uses and pay posted rates into a separate account; otherwise the capacity might be overforecast at no cost.

PECO requests that the Commission clarify that the requirement that a transmission provider take service under its own transmission tariffs does not apply to: (1) Retail service, (2) existing wholesale contracts, and (3) pooling arrangements. UNITIL claims that the requirement for a transmission provider to take service under its own tariff and to post its own tariff rate should not apply to pool transactions where a single pool-wide rate is applied.

A number of IOUs contend that it is not necessary for the transmission provider to take service under the network tariff because both the transmission provider and the network customers cannot use the tariff to make off-system sales. LILCO states that it is appropriate to distinguish between a transmission owner's use of its transmission system to make: (1) Wholesale bulk power sales; and (2) off-system purchases to serve its native load retail customers. LILCO contends that in the second situation it should not be required to take transmission service under its own open access tariffs.

EGA argues that transmission owners should be required to take transmission service under open access tariffs for both wholesale off-system sales and purchases. It maintains that, as retail competition increases, utilities will eventually have to take retail service under their own tariffs. Power Marketing Association believes that comparability can be achieved only if transmission service provided in connection with coordination transactions is unbundled and the transmission provider takes such transmission service under its tariff.

Consumers Power also claims that there is an inconsistency between the NOPR text, the tariffs, and the proposed regulatory language regarding whether the requirement for a utility to take service under its own tariff applies only to new wholesale transactions.

Commission Conclusion

We conclude that public utilities must take all transmission services for wholesale sales under new requirements contracts and new coordination contracts under the same tariff used by others (eligible customers).[341] For sales and purchases under existing bilateral economy energy coordination agreements, we will give an extension until December 31, 1996, for public utilities to take transmission service under the same tariff used by others.[342] As further discussed in Section IV.F., we will also give an extension of time to December 31, 1996, for certain existing power pooling and other multilateral coordination agreements to comply with this requirement. This will ensure that utilities live by their own rules for wholesale transactions and that we can achieve non-discriminatory open access transmission. In the case of a public utility buying or selling at wholesale, the public utility must take service under the same tariff under which other wholesale sellers and buyers take service.

2. Accounting Treatment

In the NOPR, we did not address any accounting aspects of our proposed rule.

Comments

IOUs generally object to a requirement that they pay themselves for their use of the transmission system.[343] NEPCO claims that it is a general principle of accounting that an enterprise cannot recognize and record revenues to itself. NEPCO suggests that, to ensure that utilities' financial statements are not misleading, this aspect of functional unbundling can and should be accomplished through the ratemaking process, rather than by requiring utilities to actually charge themselves revenues for taking transmission services.[344]

Atlantic City Electric states that the added costs of properly administering and accounting for these transactions separately will increase prices to ultimate consumers. It contends that ensuring that operators do not give undue preference to transactions of the transmission provider makes it unnecessary for a utility to charge itself.

CSW argues that some of the provisions of the tariffs were specifically designed for third parties and do not make sense as applied to the transmission provider (*e.g.*, signing service agreements and running credit checks).[345]

Most IOUs suggest that a revenue credit mechanism be used to account for a transmission provider's use of its system. Florida Power Corp states that revenue credits should be equal to the utility's posted rates for transmission service multiplied by the amount of capacity reserved and/or energy transmitted by the utility.

Otter Tail proposes a revenue credit that allocates revenues based on use under the tariff of the utility's transmission investment and credits these revenues against the firm load customers' accounts.

Duke asserts that the transmission provider should maintain records reflecting transmission for its own transactions under the tariff and develop appropriate revenue credits for transmission rates. It also believes that all firm users of the transmission system should receive credits for all non-firm uses.

Allegheny Power states that the crediting of non-firm revenues to network customers would have to be done on an after-the-fact basis when their loads would be known. However, it believes that revenue crediting should occur only if the firm service customer has retained the utility to remarket the customer's unused capacity.

Cajun proposes that all transmission revenues in excess of those implicitly included in the development of the transmission rates, including those that the utility has charged itself, be credited

[338] *But see* discussion of buy/sell transactions in Section IV.I.

[339] FERC Stats. & Regs. ¶ 32,514 at 33,080.

[340] *E.g.*, Michigan Systems, Cleveland, Municipal Energy Agency Nebraska, Missouri Basin MPA, TAPS, Wisconsin Municipals, LG&E, NIEP, CCEM.

[341] With the exception of certain contracts and agreements executed on or before 60 days after publication of the Final Rule in the Federal Register, the regulation we are adopting requires that public utilities take service under their open access tariff for wholesale sales or purchases of electric energy and unbundled retail sales of electric energy, effective on the date the public utility engages in such transactions.

[342] As discussed in Section IV.F., the Commission will not impose this requirement on existing bilateral non-economy coordination agreements, but persons may file complaints that such agreements need to be modified.

[343] *E.g.*, EEI, Con Ed, VEPCO.

[344] *See also* NEPCO.

[345] *See also* Florida Power Corp.

back to the network service transmission customers on a load ratio share basis. If transmission service rates are formula rates that are recalculated annually, Cajun proposes that excess transmission revenues be used to offset the recalculated revenue requirement. If the rates are not formula rates, Cajun states that an explicit tracker with monthly crediting to the network customer must be used.

To avoid cross-subsidization between affiliates and third parties, NRECA suggests that transmission revenues ''paid'' by a utility's generation function to its transmission function be credited back to the utility's nonaffiliated customers, and that any rate discounts extended to the generation function by the transmission function be filed with the Commission with a full explanation of why the discount was extended together with a showing that the discount was made available to all other similarly situated customers.

APPA contends that the Commission's current system of revenue crediting could give transmission owners an unfair competitive advantage by allowing them to use the revenue credit to subsidize the price at which they sell power. It argues that transmission owners should pay the actual price of transmission rather than booking a revenue credit as an offset to the cost of transmission service.

TAPS and Wisconsin Municipals argue that an essential element of true comparability is the ongoing pass-through to network customers of a load ratio share of transmission revenues generated by third-party and the transmission provider's off-system uses of the transmission system.

Houston L&P suggests that the revenue crediting mechanism proposed in the NOPR could be established to recognize the utility's transmission service revenue and expenses in non-third-party wheeling transactions by reclassifying a portion of its revenue equal to the cost of transmission services provided to itself during such transactions. This mechanism would not reclassify expense accounts, but would distinguish that transmission portion of the total transaction's revenue that was associated with covering the cost of transmission service, using the rates charged in similar third-party transactions.

PacifiCorp contends that the Commission should enforce the requirement that utilities account for revenues they pay themselves through the commission's audit powers and through complaint proceedings. It specifically recommends that each transmitting utility be required to indicate, in its Form No. 1 under Account 456, the megawatts and revenues associated with its firm and non-firm off-system sales.[346]

MT Com states that the embedded costs that the Commission functionalizes for jurisdictional purposes should be carefully reconciled with plant balances used to calculate other costs of service.

CCEM wants each transmission provider to charge and book revenues into separate accounts for (1) service provided to itself and off-system sales and third-party sales under the tariffs, (2) impact study costs that the provider performs for itself or an affiliate, and (3) ancillary service revenues, net of out-of-pocket expenses the transmission owner provides itself or an affiliate.

Arizona Public Service recommends that any revenue crediting or booking be prospective only and that enforcement occur through the Commission's periodic audits and a utility's rate cases.

Many IOUs argue that there should be no obligation to credit non-firm transmission revenues to customers who are not using their firm capacity.[347] PacifiCorp contends that all non-firm revenues should be credited against total annual revenue requirements, resulting in lower rates to all customers. Wisconsin P&L maintains that non-firm sales revenue should be shared with all network customers.

Otter Tail argues that non-firm transactions between existing utilities to support and achieve real-time system optimization should be permitted without charge to the transmission owner. CSW asserts that no credits should be made for the non-firm secondary service under the point-to-point tariff and that off-system purchases for native load should not result in a revenue credit.

Southwestern suggests that the Commission not require the crediting of a transmission component associated with off-system purchases by the public utility. Southwestern argues that a credit would interfere with a utility's ability to buy the most economic energy for its native load customers. It also argues that requiring a credit is not comparable to what network customers pay. NEPCO points out that crediting transmission associated with purchases would require native load customers to pay the costs of the utility's purchasing off-system power while network customers do not have to pay a separate point-to-point charge for their off-system purchases. Southwestern claims that the crediting requirement would double-charge the transmitting utility and its native load customers because a utility's off-system purchases directly relate to the load it serves, and that load already is reflected in the transmission rate calculation. Southwestern also claims that it is unclear from the NOPR whether the Commission considers sales from the renewal of existing wholesale requirements contracts as being subject to crediting. It argues that transmission related to these sales should not be subject to the crediting requirement because this is service to native load customers.

Brazos opposes imputing revenues associated with a utility's own use of its transmission system because this will artificially increase the cost of power and deny consumers the benefits of economy energy sales made at market-based prices.

Commission Conclusion

While we used the word ''accounting'' in the NOPR, the real issue is assuring that utilities bear the costs associated with their own uses of the system in a manner comparable to how they charge others. Accordingly, this is a rate issue, not an accounting issue. However, we direct utilities to account for all uses of the transmission system and to demonstrate that all customers (including the transmission provider's native load) bear the cost responsibility associated with their respective uses.[348]

D. Ancillary Services

In the NOPR, the Commission stated that several ancillary services are needed to provide basic transmission service to a customer. These services range from actions taken to effect the transaction (such as scheduling and dispatching services) to services that are necessary to maintain the integrity of the transmission system during a transaction (such as load following and reactive power support). Other ancillary services are needed to correct for the effects associated with undertaking a transaction (such as energy imbalance service).

We proposed six ancillary services to be offered in an open access transmission tariff, which we called (1) scheduling and dispatching services, (2) load following service, (3) energy imbalance service, (4) system protection service, (5) reactive power/voltage control service, and (6) loss compensation service. We requested

[346] If the utility is not required to file a Form No. 1, PacifiCorp states that it should be required to file similar information annually.

[347] *E.g.*, Consumers Power, Northern States Power, PacifiCorp, Allegheny Power.

[348] Additional guidance on this subject is in Section IV.G.4.g.(2)(a).

comments on all aspects of ancillary services, including whether the identified ancillary services are appropriately defined, whether other services should be included, and how these services should be supplied.

Commenters identified a number of other services that may be provided as part of interconnected operations. After considering the comments, we conclude that the following six ancillary services must be included in an open access transmission tariff:

(1) Scheduling, System Control and Dispatch Service;

(2) Reactive Supply and Voltage Control from Generation Sources Service;

(3) Regulation and Frequency Response Service;

(4) Energy Imbalance Service;

(5) Operating Reserve—Spinning Reserve Service; and

(6) Operating Reserve—Supplemental Reserve Service.

A description of these services and our reasons for designating them as ancillary services are included in section 1 below. We also discuss in that section our rationale for excluding other services from the list of ancillary services that must be included in an open access transmission tariff. In section 2 below, we discuss which of the six ancillary services the transmission provider must provide or offer to provide to transmission customers, and which the transmission customer must purchase from the transmission provider. These requirements are summarized as follows:

(1) Scheduling, System Control and Dispatch Service (Transmission Provider must provide and Transmission Customer must purchase from Transmission Provider);

(2) Reactive Supply and Voltage Control from Generation Sources Service (Transmission Provider must provide and Transmission Customer must purchase from Transmission Provider);

(3) Regulation and Frequency Response Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply);

(4) Energy Imbalance Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply);

(5) Operating Reserve—Spinning Reserve Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply); and

(6) Operating Reserve—Supplemental Reserve Service (Transmission Provider must offer to provide only to Transmission Customer serving load in Transmission Provider's control area and Transmission Customer must acquire, but may do so from Transmission Provider, a third party or self supply).

Our requirement that these six ancillary services be included in an open access transmission tariff does not preclude the transmission provider from offering voluntarily to provide other interconnected operations services to the transmission customer along with the supply of basic transmission service and ancillary services.[349]

1. Definitions and Descriptions

Comments

Commenters generally agree that some ancillary services are needed for transmission of power. Some commenters, however, argue for a different name or description for the ancillary services we proposed in the NOPR. Others argue for a more extensive list of services.

EEI believes that the term ''ancillary'' is a confusing description because the services are integral to providing transmission service. NERC, PSE&G, and others claim that ancillary services are not, as the term ''ancillary'' implies, subordinate or auxiliary to the transmission of power; rather such services are conjunctive and required to allow reliable operation of an electric system. BG&E and others contend that ancillary services should be defined as services for control area operation,[350] and not as services provided by an individual, noncontrol area utility. NERC proposes, and many IOU commenters support, an alternative name for these services, ''Interconnected Operations Services.'' NERC contends that the alternative name better reflects the fact that the services are needed in the broader context of allowing control areas, transmission customers, and other operating entities to operate reliably and equitably.

Some commenters propose a greater number of ancillary services. They argue that the services we proposed can be broken down into more discrete functions. A number of commenters provide rather lengthy lists of possible ancillary services to supplement those identified in the NOPR.[351]

NERC identifies twelve services, which it groups into three broad categories: interchange scheduling services, generation services, and transmission services. NERC's proposed interconnected operations services are:

(a) interchange scheduling services:

(1) System control and dispatch services; and

(2) Accounting;

(b) generation services:

(1) Regulation service;

(2) Energy imbalance service;

(3) Frequency response service;

(4) Backup supply service;

(5) Operating reserve service: spinning reserve and supplemental reserve services;

(6) Real power loss service;

(7) Reactive supply (from generation resources) and voltage control service; and

(8) Restoration service; and

(c) Transmission services:

(1) Facilities use; and

(2) Reactive supply (from transmission resources).

NERC also identifies dynamic scheduling as a unique type of dispatch service that control areas must have responsibility over to ensure reliability.

Houston L&P proposes a substitute list of twenty services. NYPP proposes a substitute list of thirty-eight ''unbundled components for transmission service,'' which include twelve generation-related services and twenty-six operations-related services. Oak Ridge recommends that the Commission consider using seven ancillary services, which closely conform to the six services described in the NOPR.[352] Although Oak Ridge identifies several additional ancillary services, it recommends that these services not be included in the list of services to be required because they cannot be measured or because the cost

[349] Of course, public utilities would have to have a rate schedule on file to provide other jurisdictional interconnected operations services.

[350] A control area is part of an interconnected power system with a common generation control system. It may contain one or several utilities. The operator of the control area is responsible for balancing generation and load and for maintaining reliable system operation.

[351] *E.g.*, Oak Ridge, Houston L&P, Carolina P&L, NYPP.

[352] Oak Ridge originally identified nineteen ancillary services, which included a recommended separation of the six NOPR ancillary services into twelve services and seven additional new services.

of metering and billing outweighs the cost of these services.

Commission Conclusion

We will adopt NERC's recommendations for definitions and descriptions with modifications. Starting with NERC's Interconnected Operations Services, we identify some of these as ancillary services that must be offered with basic transmission service under an open access transmission tariff.[353] The definitions developed by NERC for the individual services reflect the current position of a broad spectrum of experts on the subject of interconnected operations. Adoption of NERC's terminology will provide a more universally accepted set of definitions of services. We will retain the term ''ancillary services,'' which will refer to those interconnected operations services that we will require transmission providers to include in an open access transmission tariff.

The interconnected operations services identified by NERC incorporate all of the ancillary services proposed in the NOPR. We believe, however, that several of the individual services identified by NERC do not warrant classification as unbundled ancillary services due to the small cost involved (*e.g.*, accounting). NERC also has identified services that, while capable of being provided in the context of integrated operations, are more appropriately provided for in a separate service agreement or other contractual arrangement (*e.g.*, dynamic scheduling, loss compensation service). NERC and others have attempted to identify all interconnected operation services that could be provided by a control area. The thoroughness of the comments received on this issue has been invaluable to the Commission's deliberations.

We will require that an open access transmission tariff include the six ancillary services that we have identified as necessary for the transmission provider to offer to transmission customers. These are needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service. Other interconnected operations services, such as loss compensation service, may be provided by the transmission provider or third parties to facilitate a particular transaction or operating arrangement. We will not require other interconnected operations services as part of an open access transmission tariff. If a transmission provider supplies such services voluntarily, they may be added to a customer's service agreement with the transmission provider.

As mentioned, we will adopt NERC's definitions with modifications, and we name and describe the six ancillary services below. After each service name, we list in parenthesis the service name in the NOPR that most closely corresponds to the service defined. In the discussion, we explain whether and how we modified NERC's term.

a. The Six Ancillary Services

(1) Scheduling, System Control and Dispatch Service (in the NOPR: Scheduling and Dispatching Service)

Comments

NERC proposes a System Control and Dispatch Service, which provides for (i) interchange schedule confirmation and implementation with other control areas, including intermediary control areas that are providing transmission service, and (ii) actions to ensure operational security during the interchange transaction. A transmission customer may schedule interchange with another control area operator or with another entity inside another control area; however, the control area operators are responsible for confirming and implementing the interchange into or out of their respective areas on behalf of the transmission customer.

NERC also proposes a separate Accounting Service, which provides for energy accounting and billing services associated with interchange. Accounting Service would be provided by the operator of the control area in which the transmission service takes place.

Commission Conclusion

We adopt ''Scheduling, System Control and Dispatch'' as the name for an ancillary service. It substitutes for the NOPR's Scheduling and Dispatching Service.

The name is NERC's recommendation with two modifications. First, we include the term ''scheduling'' in the name of this service because a control area operator/transmission provider must take on the function of scheduling on behalf of customers. Second, we will not require Accounting as a separate ancillary service. The purpose of separating accounting as a stand-alone service would be to allow customers to take it separately from scheduling and system control. However, we believe that accounting for scheduling, system control and dispatch is not separable from these other functions and that accounting costs are likely to be small. Therefore, accounting does not warrant separate service status. The cost of accounting for these services should be included in the cost of Scheduling, System Control and Dispatch Service.

(2) Reactive Supply and Voltage Control From Generation Sources Service (Formerly Reactive Power/Voltage Control Service)

Comments

A number of commenters explain that reactive power and voltage control service is integrally related to the reliable operation of the transmission system. These commenters also note that reactive power and voltage support must be supplied at the location where it is needed.[354] It cannot be provided by a distant supplier.[355]

NERC indicates that reactive supply is necessary to maintain the proper transmission line voltage for the transaction. NERC states that reactive supply is provided from both generation resources and transmission facilities (*e.g.*, capacitors), and lists its provision as two services, distinguished by the facilities that supply them.[356] NERC further distinguishes reactive supply service based on the source of the need for the service: (1) Reactive supply needed to support the voltage of the transmission system and (2) reactive supply needed to correct for the reactive portion of the customer's load at the delivery point.

Commission Conclusion

We adopt ''Reactive Supply and Voltage Control from Generation Sources'' as the name for an ancillary service. It substitutes for the NOPR's Reactive Power/Voltage Control Service.

We accept NERC's identification of two ways of supplying reactive power and controlling voltage. One is to install facilities, usually capacitors, as part of the transmission system. We will consider the cost of these facilities as part of the cost of basic transmission service. Providing reactive power and voltage control in this way is not a separate ancillary service.

The second is to use generating facilities to supply reactive power and voltage control. This use is the service

[353] NERC indicates that the list of services is a work in progress and therefore may not be a complete list. NERC has formed an independent Interconnected Operations Services Working Group (Working Group). The Working Group includes representatives with a broad range of industry interests (transmission-dependent, partial requirements, IPP, transmission-owning, public power). We encourage this effort and will consider future changes to the list of ancillary services or their descriptions to reflect the further development of concepts in this area.

[354] *See, e.g.*, APPA.

[355] *E.g.*, EEI, NERC, NYSEG, FPL, NSP.

[356] *See also* APPA.

named here, which must be unbundled from basic transmission service.

We note, however, that customers have the ability to reduce (but not eliminate completely) the reactive supply and voltage control needs and costs that their transactions impose on the transmission provider's system. For example, customers who control generating units equipped with automatic voltage control equipment can use those units to respond to local voltage requirements and thereby reduce a portion of the reactive power requirements associated with their transaction.[357]

In addition, transmission customers that serve loads can minimize the reactive power demands that they impose on the transmission system by maintaining a high power factor at their delivery points. A poor power factor at a customer's delivery point creates a need for either transmission reactive facilities (*i.e.*, capacitors) or local generator-supplied voltage support.[358]

However, these transmission customer actions do not eliminate entirely the need for generator-supplied reactive power. The transmission provider must provide at least some reactive power from generation sources. For this reason, and because a transmission customer has the ability to affect the amount of reactive supply required, we will require that reactive supply and voltage control service be offered as a discrete service, and to the extent feasible, charged for on the basis of the amount required.[359]

(3) Regulation and Frequency Response Service (in the NOPR: Load Following Service)

Comments

Someone must supply extra generating capacity, called regulating margin, to follow the moment-to-moment variations in the load located in a control area. Following load variations is necessary to maintain scheduled interconnection frequency at sixty cycles per second (60 Hz).

NERC and others support the need for someone to provide load following service to have generation follow a transmission customer's load changes; someone must supply power to meet any difference between a customer's actual and scheduled generation. Usually, the control area operator provides this service, but it is possible for a customer to arrange for someone else to follow its variations in load.

Many commenters indicate that the industry commonly refers to this service as ''Regulation Service.'' [360]

Also, NERC proposes that Frequency Response Service be identified as a related but distinct service. NERC indicates that all control areas are expected to have generation and control equipment to respond automatically to frequency deviations in their networks.

Commission Conclusion

We adopt ''Regulation and Frequency Response'' as the name of an ancillary service. It substitutes for the NOPR's Load Following Service. This name conforms to the terminology recommended by NERC.

We conclude that Regulation Service and Frequency Response Service are the same services that make up the Load Following Service referenced in the NOPR. While the services provided by Regulation Service and Frequency Response Service are different, they are complementary services that are made available using the same equipment. For this reason, we believe that Frequency Response Service and Regulation Service should not be offered separately, but should be offered as part of one service.

(4) Energy Imbalance Service (the Same in the NOPR)

Comments

Many commenters explain that Energy Imbalance Service, as proposed in the NOPR, is necessary when transmission service is provided in a control area that contains the load being served.[361] Energy Imbalance Service supplies any hourly mismatch between a transmission customer's energy supply and the load being serving in the control area. That is, this service makes up for any net mismatch over an hour between the scheduled delivery of energy and the actual load that the energy serves in the control area. In contrast, Regulation and Frequency Response Service corrects for instantaneous variations between the customer's resources and load, even if over an hour these variations even out and require no net energy to be supplied.

Commission Conclusion

We will adopt ''Energy Imbalance'' as the name for an ancillary service. This is the same name proposed in the NOPR. NERC's description is the same as the service proposed in the NOPR.

(5) Operating Reserve—Spinning Reserve Service and

(6) Operating Reserve—Supplemental Reserve Service (in the NOPR These Two Were Formerly System Protection Service)

Comments

Many commenters express confusion regarding the NOPR term ''system protection.'' They indicate that the term ''system protection,'' is described in the NOPR as furnishing operating reserve, but has another meaning in the industry.[362]

Operating reserve is extra generation available to serve load in case there is an unplanned event such as loss of generation. Generation held for operating reserve should be located near the load, typically in the same control area. Operating reserve amounts are set by the region, subregion, or a reserve sharing group in which the transmission customer's load is electrically located.

NERC and other commenters recommend the commonly-used name, ''operating reserve,'' for this service. NERC also indicates that there are two types of operating reserve: spinning reserve and supplemental reserve.

Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output. They are available to serve load *immediately* in an unexpected contingency, such as an unplanned outage of a generating unit.

Supplemental reserve is also generating capacity that can be used to respond to contingency situations. Supplemental reserve, however, is not available instantaneously, but rather within a short period (usually ten

[357] The ability to reduce reactive power requirements will be affected by the location and operating capabilities of the generator. Any arrangement for the customer to self-supply a portion of reactive supply should be specified in the transmission customer's service agreement with the transmission provider.

[358] Transmission providers may propose delivery point power factor standards, including additional (penalty) charges for failure to maintain specified power factors, in service agreements with customers. We will evaluate the reasonableness of any such proposals by public utilities to determine whether they conform to prudent utility practices and are comparable to requirements imposed by the utility on other customers, including the utility's own requirements customers, and are otherwise just and reasonable.

[359] Separation of reactive supply and voltage control from basic transmission service also may contribute to the development of a competitive market for such service if technology or industry changes result in improved ability to measure the reactive power needs of individual transmission customers or the ability to supply reactive supply from more distant sources. We recognize that these capabilities may not be fully developed at present and the ability to distinguish the reactive power needs of individual customers may be limited at first to generator control and power factor correction.

[360] *E.g.*, NERC, EEI, Florida Power Corp.

[361] *E.g.*, NERC, EEI.

[362] *E.g.*, EEI, Florida Power Corp, TVA, Wollenberg.

minutes). Supplemental operating reserve is provided by generating units that are on-line but unloaded, by quick-start generation, and by customer-interrupted load, *i.e.*, curtailing load by negotiated agreement with a customer to correct an imbalance between generation and load rather than increasing generation output.

Commission Conclusion

We adopt Operating Reserve—Spinning Reserve Service and Operating Reserve—Supplemental Reserve Service as the names of two related, but distinct, ancillary services. They substitute for a single ancillary service in the NOPR, System Protection Service. The names conform to the terminology recommended by NERC. We distinguish them because these services may be subject to different reliability requirements; the resources that supply each service may not be the same; and the two services may be provided by different suppliers.

b. Other Services Discussed in the NOPR

Commenters discussed whether two other services that were discussed in the NOPR should be designated as ancillary services.[363] Although we do not designate these as ancillary services for purposes of this Rule, we discuss the names and descriptions here so that we can discuss our policy regarding these services.

(1) Real Power Loss Service (in the NOPR: Loss Compensation Service)

In the NOPR, we proposed that Loss Compensation be an ancillary service.

Comments

NERC recommends the term, ''Real Power Loss,'' to refer to energy consumed in transmission, much of it by resistance heating of the lines and transformers. Many parties, including NERC, comment that there are a number of ways to compensate the transmission provider for the losses that occur in providing transmission service. They indicate that real power loss service can be obtained from a variety of sources, such as the power supplier, the customer, a third-party, the transmission provider, or another control area. Also, the loss is commonly accounted for by a transmission customer receiving less energy at the point of delivery than it provides to the transmission provider at the point of receipt. The difference between delivered and received energy can be set equal to the energy lost in transmission.

Commission Conclusion

We adopt the term ''Real Power Loss'' as the name of this interconnected operations service. It substitutes for the Loss Compensation service described in the NOPR. This name conforms to the terminology recommended by NERC.

Although proposed as an ancillary service in the NOPR, we will not require that Real Power Loss be included as an ancillary service in an open access transmission tariff. It is not necessary to require the transmission provider to supply energy losses to the transmission to ensure comparable transmission access. Real Power Loss is more appropriately an interconnected operations service that transmission providers may offer voluntarily to provide to transmission customers.

It is not necessary for the transmission provider to supply Real Power Loss to effect a transmission service transaction. The transmission provider is not uniquely situated to provide Real Power Loss service to its customers, nor does it have a comparative advantage over anyone in providing such a service. Indeed, to require the transmission provider to provide this service would effectively obligate the transmission provider to engage in a sale of power when such a sale is not needed to effect the transmission service transaction.

As noted in the comments, customers have several options to cover losses that occur when electricity moves across transmission facilities.[364] The availability of open access permits the customer to obtain energy losses from many regional suppliers.

Although we will not require the transmission provider to supply Real Power Loss to the transmission customer nor require the customer to purchase it from the transmission provider, the customer must make provision for Real Power Loss. It cannot take basic transmission service without such a provision. A customer seeking transmission service must bring to the transaction sufficient energy and capacity to replace the losses associated with its intended transaction.[365] Consequently, we will require that the transmission customer's service agreement with the transmission provider identify the party responsible for supplying real power loss. In addition, we will require that the transmission provider indicate, either in its tariff or on its OASIS, what the energy and capacity loss factors would be for any transmission service it may provide so that potential customers will know the amount of losses to replace.

(2) Dynamic Scheduling (the Same in the NOPR)

In the NOPR's discussion of Scheduling and Dispatch Service, we pointed out that dynamic scheduling is possible in some regions. We asked for comments on whether we should require dynamic scheduling as an ancillary service, given the complexity of the service.

Comments

Most commenters would not have us require Dynamic Scheduling as an ancillary service.[366] Dynamic scheduling provides the metering, telemetering, computer software, hardware, communications, engineering, and administration required to allow remote generators to follow closely the moment-to-moment variations of a local load. In effect, dynamic scheduling electronically moves load out of the control area in which it is physically located and into another control area.

Commission Conclusion

We adopt the name Dynamic Scheduling Service, but we will not designate it as an ancillary service that must be included in an open access transmission tariff.

In the NOPR, we noted that Dynamic Scheduling could be used in a transmission transaction if it is technically feasible to do so without adversely affecting reliability. We did not propose in the NOPR that Dynamic Scheduling be named an ancillary service. Although Dynamic Scheduling is closely related to Scheduling, System Control and Dispatch Service, it is a special service that is used only infrequently in the industry. It uses advanced technology and requires a great level of coordination. Each Dynamic Scheduling application has unique costs for special telemetry and control equipment, making it difficult to post a standard price for the service.

Consequently, we will not require that the transmission provider offer Dynamic Scheduling Service to a transmission customer, although it may do so voluntarily. If the customer wants to

[363] In addition, NERC designates ''facilities use service'' as an interconnected operations service. We note that the facilities use service described by NERC is simply basic transmission service, which must be provided under an open access tariff. We do not consider facilities use service to be an ancillary service.

[364] *See, e.g.*, Portland, APPA, PacifiCorp, EEI.

[365] If a transmission provider does not charge for transmission used to supply losses for its own wholesale power sales and purchases, it may not charge others. If it charges others, it must charge for its own uses.

[366] *E.g.*, Detroit Edison, El Paso, FPL, Minnesota P&L, NIPSCO.

purchase this service from a third party, the transmission provider should make a good faith effort to accommodate the necessary arrangements between the customer and the third party for metering and communication facilities.

c. Other Services Not Discussed in the NOPR

Comments

Some commenters identified several other services that were not discussed in the NOPR, which they recommend we require to be provided as ancillary services.[367] Examples are emergency power, supplemental power, and inadvertent power.

Commission Conclusion

We believe that these other services generally refer to either (1) generation services that are not related to providing transmission or (2) a subpart of a service discussed above, the cost of which is not easily separable from the other service. Consequently, we will not name any of these services as an ancillary service that a transmission provider will be required to offer separately under an open access transmission tariff. However, generation-related services may be offered voluntarily to the transmission customer.

We discuss below two of these proposed generation-related ancillary services, which NERC included among its proposed interconnected operations services.

(i) Backup Supply Service

Comments

NERC explains that Backup Supply is electric generating capacity and energy that is provided to the transmission customer as needed (1) to replace the loss of its generation sources and (2) to cover that portion of the customer's load that exceeds its generation supply for more than a short time. NERC notes that Backup Supply Service is a long-term service, which distinguishes it from Operating Reserve Service and Energy Imbalance Service. Backup Supply service replaces temporary use of operating reserves; it serves load after operating reserves are returned to standby mode to maintain operating reserves at required levels. Backup Supply may last for hours, weeks, or longer. NERC indicates that a transmission customer could reduce its need for backup supply service by using interruptible load control or active demand-side management control, or both.

Commission Conclusion

We accept the term ''Backup Supply'' as the name for this interconnected operations service, but we will not require this service as an ancillary service under an open access transmission tariff. Backup Supply Service is not required for comparable open access transmission service.

Backup Supply Service is an alternative source of generation that a customer can use in the event its primary generation source becomes unavailable for more than a few minutes. Although we believe that the two short-term operating reserve services (spinning and supplemental) are necessary to support transmission, we conclude that long-term service is not necessary. Backup Supply is a generation service that may reasonably be viewed as the responsibility of the transmission customer, who may contract for backup service or curtail load.

We will impose no obligation on the transmission provider to provide power to the customer for a time longer than specified in the tariff for the customer's own backup power supply to be made available. The transmission provider is obligated to protect against emergencies for a short time; it has no obligation to furnish replacement power on a long-term basis if the customer loses its source of supply. The transmission provider has no obligation to provide power for the weeks necessary for unit maintenance, for example.

The transmission provider is not uniquely situated to provide Backup Supply Service to its transmission customers, nor does it have a comparative advantage over others in providing such service. Moreover, as Backup Supply Service may require substantial amounts of generation capability, it is inappropriate to require the transmission provider to assume significant generation responsibilities as we functionally unbundle transmission from generation.

Although the transmission provider will not be required to offer this service to transmission customers, it may offer voluntarily to provide Backup Supply Service to its transmission customers. Any arrangements for the supply of such service by the transmission provider should be specified in the customer's service agreement.

(ii) Restoration Service

Comments

NERC states that Restoration Service provides facilities and procedures to enable (1) a transmission provider to restore its system and (2) a transmission customer to start its generating units or restore its loads if local power is unavailable. Other commenters refer to Restoration Service as Blackstart Service, which may be provided by the operator of the host control area, another control area operator, or another generation supplier.[368]

According to NERC, close coordination with the host control area operator is absolutely necessary during system restoration operations. Under current industry practice, each control area operator is responsible for implementing a restoration plan in coordination with non-control area utilities as well other power producers. Many large generating units require startup power to restart after being out of service. Startup power may be provided, for example, by self-contained diesel engine generator sets located at a generating plant. If electric power is not available from the grid, some and perhaps many plants must obtain the necessary power from their auxiliary generators to restart plants and return the grid voltage to the proper level. Other generators without blackstart capability may rely on power from the grid to restart, once the grid is energized by others. NERC notes, however, that it may be inappropriate to rely completely on power from the grid for restart power because power from the grid may be unavailable or insufficient. Consequently, at least some power plants must have internal auxiliary power sources.

Commission Conclusion

We accept the term ''Restoration'' as the name for this interconnected operations service. We will not require the transmission provider to offer Restoration Service as a separate ancillary service in an open access transmission tariff.

Comments on Restoration Service appear to describe two services, blackstart service and planning for system restoration. Presumably, each utility and power producer will do its part through voluntary coordination and self-interest to ensure a reliable and adequate source of startup power for its generating units. We will not require a transmission provider to provide blackstart capability to transmission customers. Generators without blackstart capability can instead purchase blackstart power from any power supplier connected to the grid at an appropriate power price, if such service is available after a contingency is corrected.

[367] *E.g.,* NERC, Carolina P&L, Oak Ridge, Houston L&P.

[368] *E.g.,* Atlantic City, Oak Ridge.

The obligation to plan for restoration capability is a system control area function that rests with the transmission provider and the operator of the control area in which the transmission provider is located. The transmission provider (or its associated control area operator) generally makes arrangements with enough generators to provide the system with this capability at strategic locations on the transmission system. Thus, restoration planning is intrinsic to the transmission provider's basic transmission service and included in its cost.

2. Obligations of Transmission Providers and Transmission Customers With Respect to Ancillary Services

In the NOPR, the Commission proposed that public utilities required to file open access transmission tariffs also be required to provide unbundled ancillary services to transmission customers. Although the NOPR included a list of ancillary services to be offered by transmission providers, the NOPR did not indicate whether a customer must take basic transmission service from the transmission provider to be eligible to require the transmission provider to supply ancillary services. Comments on these issues are summarized below.[369]

Comments

Several commenters [370] distinguish generation-related ancillary services from others. Generation-related services are those that require the provider to have extra generating capacity or to provide electric energy. The remaining ancillary services are called transmission-related services or control area services. Transmission-related services would involve, for example, voltage support from transmission facilities. An example of a control area service is system control and dispatch. Commenters do not agree on how each service should be classified.

Many commenters state that only control area operators should be allowed to offer certain ancillary services, such as scheduling, system control and dispatch.[371] They believe that otherwise reliability might suffer.

Minnesota P&L states that certain ancillary services (*e.g.* reactive power from generators, load following, frequency control) should be provided exclusively by the operator of the control area where the load resides.[372] Minnesota P&L indicates that obtaining these services externally could jeopardize reliability. Several commenters claim that a control area operator must provide the scheduling, system control and dispatch service and reactive power supply service (except in cases where the customer's load is very close to the generating source).[373] Numerous commenters indicate that load following (now called Regulation and Frequency Response Service) generally is provided only by a control area operator.[374]

EEI and other commenters state that energy imbalance service must be provided by either the control area operator or some other entity that is in the control area where the customer's load is located and has real-time response capability.[375] NYSEG points out that transmission providers generally are also control area operators and thus automatically provide energy imbalance service to maintain interchange flows and control area reliability. For this reason, NYSEG believes it is important that this service remain a responsibility of the transmission provider.

SC Public Service Authority contends that ancillary services can be provided only by an entity large enough to operate at a NERC regional scale. It states that ancillary services protocols must be established regionally to support regional transmission services.

Other commenters disagree. They argue that all the generation-related ancillary services identified in the NOPR can be obtained from sources other than the transmission provider.[376] American Wind believes the ability of a transmission customer to self-supply ancillary services or purchase them from a third party will help to curb inflated prices for such services. Southwest TDU Group also claims that permitting entities outside the transmission provider's control area to provide ancillary services will enhance competition and reduce the need for Commission oversight of charges for ancillary services.

A majority of commenters support the view that the transmission-providing public utility should provide ancillary services. Many commenters do not discuss the services individually but present their views generally on the provision of ancillary services. Missouri-Kansas Industrials and CCEM support a requirement that utilities make ancillary services available through a tariff. They argue that, from a customer's point-of-view, it is extremely critical that a transmission provider be required to furnish these services under a regulated, nondiscriminatory, cost-based tariff format. NIEP argues that, until a fully competitive market for ancillary services develops, transmitting utilities should be obligated to provide or arrange for any and all of the NOPR ancillary services, to the extent that the transmission customer desires such services. Direct Service Industries emphasizes that a transmission provider should be required to provide any ancillary service that it is capable of supplying. Direct Service Industries and Utilities For Improved Transition claim that open access tariffs should state clearly that the transmission provider must secure ancillary services for a transmission customer if the transmission provider is not able to provide these services itself. Large Public Power Council contends that, during the transition to a competitive market for generation-related ancillary services, transmission providers should be required to provide all ancillary services related to generation that existing customers now take on a bundled basis. OH Com notes that transmission owners, by virtue of their position as transmission owners, are necessarily the providers of last resort for certain ancillary services. OH Com therefore believes that only transmission providers should provide ancillary services.

Several non-IOU, transmission-owning commenters, however, urge that the Commission not require transmission providers to provide ancillary services that they cannot physically supply, *i.e.*, if they lack sufficient generation, lack control area facilities, or have slow-responding generating units.[377] NRECA and TDU Systems also state that many cooperatives and transmission

[369] Some commenters suggest that transmission providers be required to provide, or transmission customers be required to purchase or self-supply, certain services other than the six ancillary services that we will require to be included in an open access transmission tariff. Because we will not require the transmission provider to offer any services other than basic transmission service and the six ancillary services, comments on requirements to provide or take other services are not included in the summary.

[370] *E.g.*, NERC, Tallahassee, IL Com.

[371] *E.g.*, BG&E, Minnesota P&L, Florida Power Corp.

[372] *See also* Florida Power Corp and Montana Power.

[373] *E.g.*, Carolina P&L, Texas Utilities, NERC, PSE&G.

[374] *E.g.*, SCE&G, Montana Power, NIPSCO, EEI, PacifiCorp. EEI and PacifiCorp indicate that dynamic scheduling of load following service is an exception to the general practice of the control area operator providing load following service.

[375] *E.g.*, Montana Power, TDU Systems.

[376] *E.g.*, Tallahassee, Wisconsin Municipals, IL Com.

[377] *E.g.*, OVEC, OG&E, Memphis, Nebraska Public Power, TDU Systems, TANC, San Francisco, Brazos.

dependent systems presently obtain ancillary services from control area utilities under specific contract terms. Consequently, if their member systems are asked to provide transmission service, they may not be able to take on the obligation to secure ancillary services under their existing contracts for transmission customers. Soyland and Pacific Northwest Coop argue that a transmission provider should not be required to supply services that it does not provide to its native load.

Most IOU commenters and others oppose a requirement that the transmission provider be obligated to provide generation-related ancillary services. They offer the following reasons: (1) The need for such services differs from one transaction to the next; (2) a transmission provider is neither uniquely qualified to provide these services, nor is it essential that such provider be the one providing these services in order to effect a transaction; (3) until it is demonstrated that these services cannot be obtained from a source other than the transmission provider, it is inappropriate to require transmission providers to supply such services; and (4) a transmission provider should have no residual obligation as a provider of last resort to plan its system to have generating resources available for the supply of ancillary services.[378] IL Com also contends that utilities should not be required to provide generation-related ancillary services under general transmission service tariffs if such services can be obtained from the bulk power market.

Other IOU commenters argue that there is a fundamental inconsistency between an obligation to provide or obtain ancillary services for customers and the NOPR's unbundling requirement. For example, BG&E claims that it is inconsistent to require the traditional vertically integrated utility to functionally unbundle and also to remain responsible for providing at cost-based rates what should be competitively-priced generation services. Florida P&L and other IOU commenters argue that providing generation-related ancillary services effectively imposes the load-serving obligation of the transmission customer on the transmission provider.

However, some IOU commenters contend that the transmission provider or its agent should be required to provide certain ancillary services.[379] NIPSCO and PacifiCorp believe that load following (now called Regulation and Frequency Response Service) should be provided only by the transmitting utility, especially if the customer's load and resources are located in the control area operated by the transmitting utility. EEI contends that a third-party generator should have the opportunity to provide regulation service if it resides in the transmission provider's control area and coordinates its actions with the control area operator.

IN Com and NY Com recommend that the Commission provide flexibility in assessing responsibility for the supply of ancillary services. MN DPS recommends that an individual transmission provider should not be required to file an individual tariff for ancillary services if it is a member of an RTG whose tariffs adequately cover the same services.

EEI contends that a control area utility should not be required to provide ancillary services to a third party outside its control area. EEI also argues that, if the transmission provider is not a control area, it should not be required to procure ancillary services from a control area on behalf of a third party seeking service over its system. Rather, the third party should be responsible for procuring the ancillary services it needs. Other IOU commenters argue that the responsibility to acquire ancillary services belongs to the transmission customer, not the transmission provider.[380]

Many IOU commenters express concern that ancillary services be offered and taken on a symmetrical basis, *i.e.,* if transmission providers are uniquely situated to provide the service, customers should likewise be required to take and pay for the service from such transmission providers.[381] BG&E claims that it is patently unfair to give third-party users the option not to purchase ancillary services that the transmission provider must offer. BG&E argues that, if transmission providers have an obligation to provide ancillary services, equity dictates that transmission customers have a corresponding obligation to take those services or compensate transmission providers for the costs associated with the unused capabilities. United Illuminating argues that the requirement to provide service without a corresponding obligation to purchase service unfairly burdens the transmission provider and skews competition in favor of transmission customers.

Other non-IOU commenters oppose a symmetric obligation to provide and purchase particular ancillary services.[382] Ontario Hydro and others claim that the customer should decide on a case-by-case basis which ancillary services it needs to purchase.

BPA and BG&E assert that transmission providers should be able to require that the party *receiving* the power, which may not be the transmission customer, be responsible for acquiring ancillary services. This would allow the transmission provider to establish the appropriate contractual arrangements with the party that is actually receiving the energy and avoid shifting responsibility to a party that is merely arranging the transmission service.

A number of IOU commenters express concern that customers may ''lean'' on a transmission provider's system for ancillary services. That is, they worry that the transmission customer may not purchase an ancillary service but nevertheless rely on the transmission provider to provide it. Commenters propose various remedies to address this concern. NIEP, Dayton P&L and others argue that the Commission should require that, as a prerequisite to basic transmission service, the transmission customer has either arranged to obtain ancillary services from the transmission provider or has demonstrated it has an arrangement with an alternative supplier that is reliable and sufficient to satisfy the ancillary service needs associated with the transmission service transaction. NYPP believes that, if the customer's method of providing ancillary services does not meet the standards of the transmission provider, the transmission provider should be able to require that the transmission customer find another ancillary service supplier or purchase the service directly from the transmission provider at its tariff rates.[383] EEI proposes that penalties be permitted as a backstop if the market cannot resolve the ''leaning'' problem. VEPCO suggests that utilities should have the option to require customers to maintain backup supply reserves.

Commission Conclusion

The NOPR proposed that six ancillary services be included in an open access transmission tariff. Some commenters interpret the NOPR to require that transmission providers make a ''universal'' offer of unbundled ancillary

[378] *E.g.,* PSNM, Atlantic City, Centerior, UWG, Texas Utilities, Entergy, LG&E, Montana Power, FPL, United Illuminating, Large Public Power Council, Christensen.

[379] *E.g.,* NIPSCO, PacifiCorp, Orange & Rockland, Allegheny, NYSEG, EEI.

[380] *E.g.,* BG&E.

[381] *E.g.,* CSW, BG&E, ConEd, United Illuminating, Ohio Edison, Atlantic City, Centerior, SoCal Edison, Duke, EEI.

[382] *E.g.,* RUS, TDU Systems, DE Muni.

[383] *See also* NYSEG, Ohio Edison.

services, *i.e.*, an offer to any transmission customer regardless of location and whether the transmission customer would also be taking basic transmission service from the supplier of ancillary services.[384] Such interpretation is incorrect; it goes beyond what is required for comparability. These services are required to be provided only to customers taking basic transmission service. However, transmission providers may offer these services on a voluntary basis to other customers if technology permits.

Transmission *through* or *out of* a control area requires fewer ancillary services from the operator of the control area than transmission *within* or *into* a control area to serve loads in the control area. If the requested transmission service transaction involves more than one control area, *i.e.*, the receipt point and delivery point of transmission service are located in different control areas, certain ancillary services will be needed only in the control area where the transmission customer's load is located.

We will distinguish two groups or categories of ancillary services: (1) Services that we will require the transmission provider to provide to all its basic transmission customers, and (2) services that we will require the transmission provider to offer to provide only to transmission customers serving load in the provider's control area. The first group is comprised of (i) Scheduling, System Control and Dispatch and (ii) Reactive Supply and Voltage Control from Generation Services. The second group is comprised of (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental.

With respect to the first group of ancillary services, we conclude that the transmission provider that operates a control area is uniquely positioned to provide these services. Thus, as stated above, we will require the transmission provider that operates a control area to *provide* these ancillary services. We will also require that the transmission customer purchase these services from the transmission provider, as explained in the next section.

With respect to the second group of ancillary services, we conclude that the transmission provider is not always uniquely positioned to provide these services, although in many cases it may be the only practical source. Thus, we will require the transmission provider to *offer* to provide the ancillary services in the second group to transmission customers serving load in the transmission provider's control area. We also will require the transmission customer serving load in the transmission provider's area to acquire these services, but it may do so from the transmission provider, a third party or self-supply. These ancillary services must be provided by someone if the system is to be operated reliably; the customer may not decline the transmission provider's offer of ancillary services unless it demonstrates that it has acquired the services from another source. The transmission provider may require the customer to decide which of these ancillary services it will purchase from the transmission provider when it applies for basic transmission service.

If the transmission provider is a public utility providing basic transmission service but is not a control area operator, it may be unable to provide some or all of the ancillary services we require without substantial investment. In this case, we will allow the transmission provider to fulfill its obligation to provide, or offer to provide, ancillary services by acting as the customer's agent. We will require the transmission provider to offer to act as agent for the transmission customer to secure these services from the control area operator.[385] The customer may have the transmission provider act as agent or may secure the ancillary services directly from the control area operator. As stated above, the customer may also secure the second group of ancillary service from a third party or by self-supply.

If the transmission provider is a public utility that is not a control area operator, but its control area operator is a public utility, the control area operator must offer to provide all ancillary services to any transmission customer that takes transmission service over facilities in its control area whether or not the control area operator owns or controls the facilities used to provide the basic transmission service.[386]

We discuss the requirement to supply and purchase each ancillary service individually below.

a. Ancillary Services Required To Be Provided by Transmission Provider for All of Its Transmission Customers

(1) Scheduling, System Control and Dispatch Service

We conclude that this service is necessary to the provision of basic transmission service within every control area. As NERC and other commenters point out, Scheduling, System Control and Dispatch Service can be provided only by the operator of the control area in which the transmission facilities used are located.[387] This is because the service is to schedule the movement of power through, out of, within, or into the control area.

(2) Reactive Supply and Voltage Control Service From Generation Sources

We conclude that this service is necessary to the provision of basic transmission service within every control area. Because reactive power cannot be transmitted for significant distances, the local transmission provider has to supply reactive power from generation sources. It is often uniquely situated to supply reactive power. The transmission provider or the operator of the control area in which the provider is located cannot avoid supplying it to the transmission customer, and the transmission customer cannot avoid taking at least some of this service from the transmission provider. Although a customer is required to take this ancillary service from the transmission provider or control area operator, it may reduce the charge for this service to the extent it can reduce its requirement for reactive power supply.

b. Ancillary Services Required To Be Offered Only to Transmission Customers Serving Loads in the Transmission Provider's Control Area

(1) Regulation and Frequency Response

Regulation and Frequency Response Service is not required for transmission out of or through the transmission provider's control area. We conclude that this service must be offered only for transmission within or into the transmission provider's control area to serve load in the area. Customers may be able to satisfy the regulation service obligation by providing generation with

[384] *E.g.*, PSNM, Atlantic City, Centerior, Texas Utilities, Entergy, FPL, Utility Working Group.

[385] The requirement to offer to act as agent is in lieu of the requirement for the transmission provider to supply the ancillary service to the transmission customer. Many commenters asked that we not require the transmission provider to acquire the capacity to provide ancillary services that it does not provide for itself but acquires from its control area operator. *E.g.*, EEI, NRECA, BPA, TDU Systems.

[386] If the transmission provider is a control area operator but not a public utility, we can order transmission services only upon application, pursuant to section 211 and 212 of the FPA. However, the provision of transmission services by non-public utilities would be necessary to satisfy the reciprocity condition in public utilities' open access transmission tariffs.

[387] *E.g.*, Carolina P&L, Texas Utilities, PSE&G.

automatic generation control capabilities to the control area in which the load resides. Dynamic scheduling may also be used to electronically ''move'' a remote generating unit into the appropriate control area. For customers to take advantage of these developments, a transmission provider is required to identify the regulating margin requirements for transmission customers serving loads in its control area and develop procedures by which customers can avoid or reduce such requirements.

(2) Energy Imbalance

We conclude that Energy Imbalance service must be offered for transmission within and into the transmission provider's control area to serve load in the area.

Energy imbalance represents the deviation between the scheduled and actual delivery of energy to a load in the local control area over a single hour. A transmission customer can reduce or eliminate the need for energy imbalance service in several ways. A customer can avoid taking energy imbalance service if it controls generation with load-following capabilities located in the control area. The Final Rule pro forma tariff allows unlimited changes before the hour at no additional charge to a customer's hourly schedule of energy deliveries to the control area. By changing its schedule more frequently (based on updated load information, for example), a customer can reduce or avoid energy imbalance charges. Other customer options to reduce or avoid energy imbalance charges include (i) establishing the load as a separate control area island within the transmission provider's control area with its own generation and load and (ii) removing the customer's load from the transmission provider's control area through dynamic scheduling.[388]

(3) Operating Reserve—Spinning

(4) Operating Reserve—Supplemental

We conclude that Operating Reserve—Spinning and Operating Reserve—Supplemental must be offered for transmission within and into the transmission provider's control area to serve load in the control area. Reserves should be located near load in case of unplanned unavailability of generating units serving load in the control area. We will permit transmission providers to rely upon prevailing regional practices to set reserve criteria. Transmission providers are required to facilitate efforts by customers to meet Operating Reserve obligations with their own generating resources or from third-party sources if they can satisfy the regional criteria.

If a customer uses either type of operating reserve, it must expeditiously replace the reserve with backup power to reestablish required minimum reserve levels.

3. Unbundling and Bundling Ancillary Services

a. Services That Can Be Bundled With Transmission Service

In the NOPR, the Commission proposed that transmission providers should be required to offer ancillary services as discrete services, unbundled from basic transmission service.

Comments

While most commenters support the approach to unbundling the ancillary services proposed in the NOPR, a number of commenters argue that, for technical and administrative reasons, certain services should be bundled with basic transmission service. For example, some commenters assert that Reactive Supply and Voltage Support service should be bundled with basic transmission service.[389] They argue that this service is integrally related to the operation of the transmission system, that it must be provided at or near the point of need, and that its costs are difficult to isolate and account for.[390] Other commenters argue that scheduling and dispatch service, for similar reasons, should be bundled with basic transmission service.[391]

A few commenters suggest that other services could be bundled with the basic transmission service. For example, NYSEG identifies energy imbalance service as a candidate for bundling. EEI identifies frequency regulation and NYMEX identifies frequency control as services that could be bundled with basic transmission service.

Some commenters believe that the Commission should allow utilities to file transmission tariffs that bundle all necessary transmission and ancillary services, at least as an interim measure.[392]

On the other hand, other commenters believe that a greater level of unbundling of transmission and ancillary services is necessary to facilitate the development of competitive markets and to ensure that transmission customers are able to purchase only the services they require.[393] Dayton P&L believes that all ancillary services should be offered as discrete services with separate prices. Texas Utilities asserts that generation-related ancillary services should be unbundled and separately priced.

Commission Conclusion

Although commenters raise valid concerns, they do not provide a compelling reason to require that our six ancillary services be bundled with basic transmission service. We have, however, changed the proposal in the NOPR to clarify that reactive supply and voltage support from *transmission* resources is part of basic transmission service.

Unbundling ancillary services will promote competition and efficiency in their supply. Because most generation-based ancillary services potentially can be provided by many of the generators connected to the transmission system, some customers may be able to provide or procure such services more economically than the transmission provider can. Once they are unbundled, a more competitive market may emerge to supply such services.

Also, unbundling makes possible a more equitable distribution of costs. Because customers that take similar amounts of transmission service may require different amounts of some ancillary services, bundling these services with basic transmission service would result in some customers having to take and pay for more or less of an ancillary service than they use. For these reasons, the Commission concludes that the six required ancillary services should not be bundled with basic transmission service.

With respect to the specific question of whether Reactive Supply and Voltage Control from Generation Sources should be bundled with basic transmission service, we believe that this service should remain unbundled because, as explained above, transmission customers have some ability to effect how much of this service they need and a third party may be able to supply some portion of a customer's reactive power requirements.

b. Services That May Be Offered and Sold as a Package

The NOPR indicated that ancillary services must be offered separately from one another but did not indicate if the

[388] Some of these options (*e.g.*, establishing a separate control area), while technically feasible, may be too costly or otherwise inadvisable.

[389] *E.g.*, Carolina P&L, NYSEG, FPL, NSP, WP&L, Orange & Rockland, Arizona, Salt River, SC Public Service Authority, Brazos, NY Com.

[390] *See, e.g.*, Carolina P&L Initial Comments at 56.

[391] *See, e.g.*, CCEM, Carolina P&L, NYSEG, CINergy.

[392] *E.g.*, UT Com, Washington and Oregon Energy Offices, WA Com.

[393] *E.g.*, Direct Service Industries, Mt. Hope Hydro.

transmission provider may also offer a package of ancillary services.

Comments

Several commenters support giving customers the option either to purchase ancillary services as separate and distinct services or to purchase a package of services from the transmission provider.[394] Others, such as Tallahassee, recommend that utilities be prohibited from bundling the purchase of one service with another so that a transmission customer cannot rely on the transmission provider for just one or a few of the ancillary services.

EEI and ELCON argue that the Commission should permit customers the option to request that transmission providers offer packages of selected ancillary services.[395] They and other commenters express a concern that efficiencies can be lost under a policy that precludes combining ancillary services.

Commission Conclusion

We conclude that a transmission provider must offer and price the individual ancillary services separately. It may not tie the purchase of one to the purchase of another.

However, we will allow a transmission provider to assemble packages of ancillary services (*not* bundled with basic transmission service) that can be offered at rates that are less than the total of individual charges for the services if purchased separately. It may also offer rate discounts on any ancillary service. If a rate discount is offered to the transmission owner itself or to an affiliate of the transmission owner, the same discount must be offered to non-affiliates, as well. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory. All discounts must be posted on the transmission provider's OASIS.

4. Reassignment of Ancillary Services

In the NOPR, the Commission noted that ancillary services may not be suitable for reassignment and requested comments on this issue.

Comments

Commenters express divided views on the reassignment issue. Some IOU commenters believe that, subject to technical limitations, ancillary services could be reassigned.[396] Other commenters, including many IOUs, oppose reassignment because they believe it is impractical.[397] In particular, PacifiCorp claims that the customer-specific nature of generation-related ancillary services prevents such services from being reassigned.

TDU Systems argue that transmission customers that must pay for ancillary services they do not need should be able to resell them to someone else.[398] Mt. Hope Hydro claims that, if a bulk power transaction and the associated transmission service can be reassigned, it is reasonable that the ancillary services used to support the transaction also should be reassigned, particularly if the same facilities and contract path are used.[399]

Commission Conclusion

We conclude that transmission customers will be allowed to reassign ancillary services along with the reassignment of basic transmission service. The Commission believes that a policy of transmission capacity reassignment may not be possible unless the ancillary services used to support the transmission are also reassignable.

5. Pricing of Ancillary Services

In the NOPR, we asked for comments on ancillary service pricing and proposed specific ancillary services prices in the Stage One implementation rates. Many commenters commented on the Stage One rates. There is no Stage One in the Final Rule.

Comments

Many commenters state that ancillary services are difficult to price. They suggest diverse pricing approaches. IN Com notes that, because utilities and regulatory commissions have no experience with pricing unbundled ancillary services, the process needs to evolve but the goal should be to encourage market pricing in competitive markets. Air Liquide believes the best pricing policy should be negotiated bilateral agreements, provided market power is mitigated.

Other commenters express concern about how pricing proposed in the NOPR would affect the development and operation of competitive ancillary services markets. Industrial Energy Applications notes that low price caps on generation-related services, such as supplying losses, imbalance energy, operating reserve and backup power, which can be provided from many sources, inhibit competitive market development. There is little incentive for other providers to invest in facilities to provide these services. Dayton P&L and others contend that the Commission should not require transmission providers to provide generation-based ancillary services at cost-based rates and then allow third parties to resell such services at market-based rates. PacifiCorp expresses concern that the NOPR's pricing proposal would be overly restrictive in the emerging competitive market for generation-related ancillary services.

Many commenters argue that cost-based price caps are appropriate for ancillary services if there are no alternative suppliers or until competitive markets develop.[400] CAMU suggests that the comparability standard is not met if market rates exceed the costs of providing ancillary services. Allegheny, Ohio Edison and Atlantic City support cost-based pricing for Reactive Power/Voltage Control. Ohio Edison recommends cost-based pricing for frequency regulation, and Atlantic City recommends it for scheduling and dispatch.

Several commenters suggest that the Commission require cost-based rates for ancillary services where no source other than the transmission provider exists and market-based rates for generation-related ancillary services if competition exists.[401] Washington and Oregon Energy Offices recommend that, before permitting market-based rates, at least two other non-affiliated parties should be able to offer a nearly identical ancillary service and that the Commission should use the same standards for allowing market-based rates for ancillary services that it has used for wholesale power sales. Mt. Hope Hydro argues that vertically integrated utilities should be permitted to charge cost-based rates that are limited to no more than the market price for ancillary services. It also contends that companies whose generation facilities are not supported by captive retail or transmission customers should be authorized to sell at market-based prices.

The vast majority of commenters from all interest groups who address market-based pricing for ancillary services agree that market-based pricing is appropriate for ancillary services where competitive market conditions exist. However, commenters disagree over whether a

[394] *E.g.*, Direct Service Industries, Mt. Hope Hydro, ELCON, PA Com.

[395] EEI Initial Comments at V–4; ELCON Initial Comments at 21.

[396] *E.g.*, WP&L, NYSEG.

[397] *E.g.*, Consumers, PacifiCorp, Carolina P&L, PSNM, Salt River, PA Com, TDU Systems.

[398] TDU Systems Initial Comments at 87.

[399] Mt. Hope Hydro Initial Comments at 17.

[400] *E.g.*, Utilities For Improved Transition, Idaho, CINergy, Direct Service Industries, Mt. Hope Hydro, ABATE, TDU Systems, Missouri-Kansas Industrials, Washington and Oregon Energy Offices, IN Com.

[401] *E.g.*, PJM, Texas Utilities, Entergy, Carolina P&L.

competitive market for ancillary services currently exists.

In determining the extent of competition, many commenters distinguish between ancillary services that are (1) generation-related and (2) transmission-related. Commenters disagree over whether the Commission can declare generation-related ancillary services to be competitive on a generic basis. Many commenters contend that transmission-related ancillary services are not available in a competitive market; consequently, they agree that prices for such services should be cost-based.

Commission Conclusion

We will consider ancillary services rate proposals on a case-by-case basis.

In response to comments,[402] we offer here some general guidance on ancillary services pricing principles.

(1) Ancillary service rates should be unbundled from the transmission provider's rates for basic transmission service, even though such services are a necessary adjunct to basic transmission service.

(2) The fact that we have authorized a utility to sell wholesale power at market-based rates does not mean we have authorized the utility to sell ancillary services at market-based rates.

(3) In the absence of a demonstration that the seller does not have market power in such services, rates for ancillary services should be cost-based and established as price caps, from which transmission providers may offer a discount to reflect cost variations or to match rates available from any third party. If a rate discount is offered to the transmission owner itself or to an affiliate of the transmission owner, the same discounted rate must be offered to non-affiliates, as well. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory. All discounts must be posted on the transmission provider's OASIS.

(4) The amount of each ancillary service that the customer must purchase, self-supply, or otherwise procure must be readily determined from the transmission provider's tariff and comparable to the obligations to which the transmission provider itself is subject. The provider must take ancillary services for its own wholesale transmission under its own tariff.

(5) The location and characteristics of a customer's loads and generation resources may affect significantly the level of ancillary service costs incurred by the transmission provider. Ancillary service rates and billing units should reflect these customer characteristics to the extent practicable.

6. Accounting for Ancillary Services

Comments

Some commenters suggest that there may be a need for revising the Uniform System of Accounts to track better the costs of providing discrete ancillary services. Other commenters believe that ancillary services are transmission-type services and suggested that the costs of generation-provided ancillary services be refunctionalized from power production expense to transmission expense.

Oak Ridge asserts that a primary goal of those interested in restructuring the electricity industry should be to identify clearly the different functions that are today buried within the vertically integrated utility and bundled into one price. Oak Ridge, however, indicates that achieving this ideal of identifying unbundled services at appropriate prices will be difficult because of utility accounting practices.

EEI asserts that since the current Uniform System of Accounts was designed to track costs incurred to provide bundled wholesale service, it does not track the discrete costs incurred to provide ancillary services. Therefore, according to EEI, a major update is needed to support the pricing of discrete ancillary services.

ConEd states that ancillary services are integral and essential elements of providing transmission services. It notes that, historically, due to the vertical integration of utilities, those services have been bundled with the other services provided and the costs associated with providing ancillary services have not been specifically defined. ConEd claims that to a large degree, this is due to the fact that utility accounting mechanisms were not established with the intention of identifying the costs for ancillary services.

UI asserts that if transmission customers are to be charged for certain ancillary services, it may be necessary to refunctionalize certain specific costs items from generation to transmission. UI points out that some of the reactive power to support system voltages and to provide transmission services, for example, is supplied from the variable reactive output of the generators. It states that these costs, to the extent they can be identified with the provision of transmission service, should be refunctionalized to the transmission account. However, UI states it may not be possible to develop a unit cost for specific transactions. Thus, UI states it may be more appropriate to roll these costs into the embedded transmission rate and allocate them among the various users of the transmission system.

Commission Conclusion

To ensure comparable transmission access a Transmission Provider is obligated to offer or arrange to provide certain ancillary services to the Transmission Customer. Also, the Transmission Provider may offer to provide other ancillary services to the Transmission Customer. A Transmission Customer is obligated to purchase certain ancillary services from the Transmission Provider.

Generation resources provide certain ancillary services, while transmission resources provide other ancillary services. Consequently, the costs of providing certain ancillary services are recorded in the utility's power production expense accounts, while others are recorded in the utility's transmission expense accounts.

Currently, the Uniform System of Accounts requires that costs incurred in providing ancillary services be recorded as power production or transmission expense depending upon which resource the utility uses to supply the service. At this time, we are not convinced that the amounts involved or the difficulty associated with measuring the cost of ancillary services warrants a departure from our present accounting requirements. We will specify, however, that revenues a Transmission Provider receives from providing ancillary services must be recorded by type of service in Account 447, Sales for Resale, or Account 456, Other Electric Revenues, as appropriate.

E. Real-Time Information Networks

In the Open Access NOPR, the Commission determined that in order to remedy undue discrimination, a utility must functionally unbundle its wholesale services, and that among the things required by functional unbundling is that the utility, when buying or selling power, rely upon the same electronic network that its transmission customers rely upon to obtain transmission information. Accordingly, the Commission accompanied its issuance of the Open Access NOPR with issuance of a notice of technical conference that initiated a proceeding in Docket No. RM95–9–000

[402] Many commenters were particularly concerned that rates for energy losses, a NOPR ancillary service, should be market-based. We need not address this concern in this Rule, however, because we will not require Real Power Losses to be offered as an ancillary service.

to consider whether Real-Time Information Networks (RINS) or some other option would be the best means to ensure that potential customers of transmission services have access to the information necessary to obtain open access transmission service on a non-discriminatory basis.[403]

The Commission affirms its conclusion that in order to remedy undue discrimination in the provision of transmission services it is necessary to have non-discriminatory access to transmission information, and that an electronic information system and standards of conduct are necessary to meet this objective. Therefore, we issue, in conjunction with this Final Rule, a final rule adding a new Part 37 that requires the creation of a basic OASIS and standards of conduct.[404]

The Phase I OASIS rules require each public utility (or its agent), as defined in section 201(e) of the Federal Power Act, 16 U.S.C. 824(e), that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to develop and/or participate in an OASIS. The Phase I OASIS rules describe what information must be provided on the OASIS during Phase I and how OASIS must be implemented.

In addition, the new Part 37 contains a code of conduct applicable to all transmission providing public utilities. The code of conduct is designed to ensure that preferential access to information about wholesale transmission prices and availability is not available to employees of the public utility engaged in wholesale marketing functions or to employees of certain of the public utility's affiliates.

F. Coordination Arrangements: Power Pools, Public Utility Holding Companies, Bilateral Coordination Arrangements, and Independent System Operators

Comments

Timing of Reformation

Many marketers, IPPs, and other nonmembers of pools request that the Commission immediately apply unbundling and transmission tariff requirements to all new transactions under existing pooling agreements. APPA states that the Commission should not deal with power pools as a ''follow-on activity'' because treatment of pools is an integral step in achieving transmission comparability. AEC contends that until pools publish open access tariffs, the Commission should permit applications for section 211 transmission orders from one or more applicants directed to multiple respondents.

Existing pools generally urge the Commission to allow time for the pools to propose alternative structures or agreements which would meet the objectives of the final rule. EEI states that the rule may create problems for power pools that will not be examined or understood by the Commission and the public until the Commission's pooling inquiry is completed; it requests that the pooling inquiry be completed before a final rule is issued. Duke recommends that implementation of open access transmission services by power pools be addressed in a separate proceeding because implementation of open access for power pools raises complex issues.

EGA, among others, argues that new transactions under existing pooling agreements should not be grandfathered, but rather should be required to meet the functional unbundling requirements of the final rule. Some pool members argue that pool transactions are largely not wholesale transactions. For example, PECO (a member of PJM) requests the Commission to clarify that the delivery of pooled generation to pool members' native load is not a ''wholesale purchase'' of power and thus would not require taking transmission service under one's own open access transmission tariff. Another member of PJM, BG&E, interprets the proposed rule to require all PJM economy trades to be firm point-to-point services; it claims that such a requirement ''jeopardizes the continued viability of the pool.''

System-Wide Tariffs

Virtually all commenters on power pool issues state that the tariff requirements should not be applied directly to individual utilities who are members of ''tight'' power pools. ELCON, CCEM, and others argue that the pro forma tariff requirement should be applied directly to ''tight'' or ''single system'' power pools to avoid discriminatory ''pancaking'' of transmission rates. However, Duke argues that where there are both multiple owners and operators, as in ''loose'' pools, it is appropriate to have individual tariffs unless the pool members agree otherwise. DOE recommends a power pool file a single pool-wide tariff to offset problems associated with joint ownership or control of transmission. CT DPUC recommends that the Commission provide guidance for transmission access and pricing (so as to avoid needless disruption of present methods).

Flexible Treatment

Most commenters on power pools support recognizing regional differences among power pools and urge flexibility. PSE&G (a member of PJM) states that open access tariffs must be specially crafted to deal with power pool members. NYPP and PJM state that they are considering innovations and urge that their efforts not be stifled by any final rule. CSW proposes a region-wide pricing model based on power flows. NPPD, a member of the Mid-Continent Area Power Pool (MAPP), says MAPP is considering adopting the megawatt-mile approach to transmission pricing. SoCal Edison states that California utilities are developing a market-based power pool and that it is crucial for the final rule to be flexible to permit innovations throughout the country.

ELCON and power marketers, however, argue for uniformity and point out the difficulties of moving power from system to system where each system has varying standards or ''pool rules.'' These commenters support uniform application of the terms and conditions in the pro forma tariffs to create a national standard.

NEPOOL emphasizes that since pools remain voluntary, the imposition of rules that are not acceptable to pool members simply increases the likelihood that members will withdraw and pools will disintegrate. For this reason, NEPOOL states that solutions to enhance competition (within a tight pool setting) are best identified through the consensus of pool members, which requires both time and flexibility on the part of the Commission.

DE, DC, NJ and MD Coms emphasizes its concern that a one-size-fits-all open-access policy, while perhaps benefiting subsets of individual suppliers and purchasers, may not be the best solution for the millions of retail customers who currently rely on power pools.[405] It wants the Commission to be aware that the individual commissions have begun a formal dialog among each other and with the PJM utilities to discuss possible regional solutions to transitional competitive issues.

Open Membership

NIEP and CCEM argue that the competitive playing field cannot be level unless nonmembers receive certain

[403] *See* Real-Time Information Networks, Notice of Technical Conference and Request for Comments, 60 FR 17726 (April 7, 1995).

[404] In Phase II, we will continue to develop the requirements for fully functional OASIS. We expect to issue a final rule on Phase II OASIS requirements sometime in 1997.

[405] *E.g.*, DE Com, DC Com, NJ Com, MD Com.

power pool services on terms comparable to those for pool members. Members of pools state that ''return in kind'' transactions are efficient, but that such transactions are not appropriate for those entities that are not similarly situated to vertically integrated utilities.

EEI maintains that those seeking the benefits of pool membership must accept the burdens imposed on existing pool members (otherwise, they would have an advantage, not comparability). EEI believes that new pool participants can negotiate and ''buy into'' the pool resources. Many commenters claim that unbundling certain power pool services to accommodate open access will solve the problem.

MidAmerican states that if the Commission grants nonmembers access to pool transmission service, the Commission should allow a period of at least four years for pools to restructure and refile rate schedules to avoid the inequitable results which the Commission's requirements will impose on pool members.

MidAmerican contends that the Commission should authorize pool members to unilaterally withdraw from their pools if any restructuring or revision of rate schedules is unacceptable to the member.

Holding Companies

Allegheny, Southern, and other holding companies argue that coordination agreements among subsidiaries of a utility holding company system do not constitute a power pool and should not be subject to any obligations the Commission may place on power pools.

Bilateral Coordination Agreements

Ohio Edison requests clarification that the Commission is not requiring new wholesale coordination transactions to be under the open access tariffs; they may be continued under existing coordination agreements. It stresses the importance of such agreements in making economy and emergency transactions.

A number of commenters agree that existing coordination contracts should not be abrogated or modified, and that transactions under these existing contracts should *not* be governed by the provisions of the pro forma tariffs.[406] These commenters generally argue that existing coordination agreements should not be abrogated or amended by the final rule because: (1) They were not negotiated in the environment envisioned by the NOPR; (2) coordination sales are beneficial to consumers and ratepayers (and thus it would not be in the public interest to curtail them); and (3) the termination of coordination agreements, which in some cases have been in place for years and are tailored to parties' peculiar circumstances, could cause severe hardships in certain regions (especially with regard to scheduling and curtailment).

PSNM contends that such agreements are the result of mutually beneficial bargaining. LPPC and MEAG argue that current contracts negotiated among parties provide cost savings to consumers, which may be foregone if existing contracts are modified. Central Louisiana suggests that the pro forma tariff provisions should be flexible enough to achieve comparability if applied to both existing and new coordination agreements.

Some commenters argue that there may be cases where it is inappropriate to modify existing coordination agreements to satisfy the requirements of the rule. They assert that coordination agreements providing for emergency transactions,[407] reliability,[408] and resource efficiency gains[409] need special attention. However, Soyland believes that existing agreements need to be reviewed if there is substantial increase in wholesale power market transactions, at the customer's option. TDU Systems argues that coordination contracts supporting system reliability should be honored and given scheduling and curtailment preference. TDU Systems contends that any amendments should be at the parties' discretion rather than by Commission mandate.

Several commenters suggest that the proposed rule is unclear about whether only existing transactions under agreements already approved by the Commission will be exempt from functional unbundling, or whether the proposed rule also would exempt (or grandfather) *new* transactions entered into pursuant to existing approved contracts.[410] Other commenters recommend that the Commission clarify that its policy on unbundling applies to all new transactions, whether pursuant to new or existing agreements.[411] ConEd and KCPL request clarification that purchases made to satisfy retail service are not subject to the requirements of the pro forma tariffs.

CCEM argues that all coordination transactions, including new transactions under existing agreements, should be unbundled to ensure that transmission providers are implementing the posted transmission rate. CINergy contends that the comparability standard should be applied to existing coordination agreements, including buy-resell agreements, to mitigate any unfair bulk power market advantages. Functional unbundling would ensure that a utility includes an EBB-posted transmission rate in the transaction charge. CINergy and Power Marketing Association recommend that the Commission use its authority under section 206 to require all utilities to file amendments to their existing coordination agreements providing for transmission service to be taken pursuant to the parties' open access transmission tariffs. Power Marketing Association further recommends that the Commission establish expedited procedures to address the situation arising from conflicting pro forma tariffs and existing coordination provisions.

Tallahassee also believes that the comparability standard should be applied to existing coordination agreements, but Tallahassee recommends that the Commission establish a transition period to allow for renegotiation among parties rather than imposing modifications to existing agreements. Renegotiation would provide an opportunity to retain previously bargained-for benefits. Detroit Edison also contends that many of the existing coordination agreements do not provide for the services required under the pro forma tariffs. Like Tallahassee, Detroit Edison recommends that the Commission allow sufficient time for parties to renegotiate existing agreements. CINergy suggests a three-year transition period.

Coordination Pricing Practices

EEI and PJM disagree with the Commission's assertion that current coordination pricing is no longer just and reasonable in the absence of an open access tariff. Ohio Edison and PA Com question the basis of the Commission's preliminary conclusion that current coordination pricing is no longer justified in the absence of a seller's tariff offer of non-discriminatory open access transmission services. PA Com asserts that the Commission's underlying assumption of general lack of transmission access by wholesale customers has not been established as fact in the proposed rule.

[406] *E.g.*, Central Louisiana, Dayton P&L, LPPC, MEAG, Missouri Basin Group, Montana-Dakota Utilities, Nebraska Public Power District, Ohio Edison, PSNM.

[407] *E.g.*, Arizona, Ohio Edison.

[408] *E.g.*, Soyland, NRECA.

[409] *E.g.*, APPA.

[410] *E.g.*, APPA, CCEM, EGA.

[411] *E.g.*, APPA, CCEM, LG&E, EGA.

MN DPS supports current coordination pricing methods provided that utilities have executed open-access tariffs. Missouri Basin Group argues that, if increased market competition materializes through open access, utilities will decreasingly rely on current coordination pricing if it no longer produces the most beneficial outcome. Missouri Basin Group recommends the Commission simply allow utilities to choose a pricing method even if a utility opts for a less beneficial outcome. Nebraska Public Power District also urges the Commission to avoid mandating coordination pricing methods. Nebraska Public Power District is concerned that this may impede establishing RTGs where such pricing is by mutual agreement and subject to ADR procedures.

Several commenters agree that current coordination pricing may no longer be appropriate in an open access regime.[412] FL Com believes that current coordination pricing should be replaced by market-based rates if open access transmission service is imposed by the Commission.

Commission Conclusion

The term ''coordination'' is applied to a wide variety of wholesale power sales agreements within the industry, including interchange, interconnection, pooling, and other agreements. Broadly speaking, any non-requirements power sales agreement can be considered to be a coordination agreement.[413]

The Final Rule's general requirement for non-discriminatory transmission access and pricing by public utilities, and its specific requirement that public utilities unbundle their transmission rates and take transmission service under their own tariffs, apply to all public utilities' wholesale sales and purchases of electric energy, including coordination transactions. The Commission has determined that certain existing wholesale coordination arrangements and agreements must be modified to ensure that necessary transmission services for such arrangements and agreements are taken under open access transmission tariffs and thus that such arrangements and agreements are not unduly discriminatory. Below we discuss how and when various types of coordination agreements will need to be modified, and when public utility parties to coordination agreements must begin to trade power under those agreements using transmission service obtained under the same open access transmission tariff available to non-parties.

Coordination arrangements, and the agreements governing them, vary widely. They range from relatively simple bilateral arrangements to complex tight power pools. Our discussion addresses four broad categories of arrangements and accompanying agreements: ''tight'' power pools, ''loose'' power pools, public utility holding company arrangements, and bilateral coordination arrangements. For purposes of implementing the non-discriminatory, open access requirements of the Final Rule, we are dividing bilateral coordination agreements into two general categories: bilateral economy energy agreements and other bilateral coordination agreements. Economy energy agreements typically provide for short-term economy trading ''if, as, and when available'' and are generally driven by the buyer and seller's generation costs. They do not require either the seller or the buyer to engage in a particular transaction. Other coordination agreements are typically longer term or open-ended. Some may involve joint ownership or joint planning of generation.[414] Others may provide joint operation of facilities so that the parties can coordinate their maintenance schedules or provide one another with emergency service. These longer-term coordination agreements are distinguished from short-term economy trading agreements in that the parties have undertaken a contractual obligation to operate their facilities so as to support one another under the conditions specified in the arrangements.

As noted in the NOPR, power pools, in contrast to most bilateral arrangements, present complex issues that may require special implementation requirements.[415] This is because these arrangements may involve agreements containing an intricate set of rights, obligations, and considerations among the members of a pool. We provide for implementation requirements herein that vary depending upon the type of ''pooling'' arrangement involved.

The Commission has concluded that in order to adequately remedy the undue discrimination in transmission access and pricing by public utilities that are members of power pools or other coordination arrangements, such public utilities must remove preferential transmission access and pricing provisions from agreements governing their transactions. The filing of open access tariffs by the public utility members of a power pool is not enough to cure undue discrimination in transmission if those public utilities can continue to trade with a selective group within a power pool that discriminatorily excludes others from becoming a member and that provides preferential intra-pool transmission rights and rates. The same holds true of certain bilateral arrangements that allow preferential transmission pricing or access. These arrangements and agreements need to be changed. We expect such arrangements and agreements to be modified by the dates indicated in this Rule. However, if necessary, we will institute section 206 proceedings against public utilities that do not make such filings.

The Commission's technical conferences on power pools, ISOs, and pro forma tariffs made clear to us the need to articulate guidance in this Rule on the restructuring or modification of unduly discriminatory coordination arrangements—particularly tight power pools.[416] They also made clear that members of tight power pools, in particular, need time to make the necessary modifications to these arrangements. We recognize that members of some power pools are already in the process of formulating voluntary modifications to pooling agreements to be filed with the Commission (*e.g.*, PJM, NYPP, NEPOOL). Therefore, we will provide adequate time for these filings as well as guidance to changes that need to be made.

In addition, although we do not at this time find it necessary to require power pools to form an independent system operator in order to remedy undue discrimination, we believe ISOs may prove to be an effective means for

[412] *E.g.*, Arizona, CINergy, Consumers Power, EEI, PJM.

[413] For example, a 30-year contract to supply 50 MW of power can be considered to be a coordination arrangement because it is not a contract to meet all of the buyer's power requirements.

[414] Agreements dealing with joint ownership or operation of transmission facilities are discussed at Section IV.C.3.

[415] The Commission did not define what it meant by ''power pools'' in the NOPR discussion. We use the term power pool in a very broad context here and have generally characterized three broad types of arrangements that represent some form of pooling: ''tight pools'', ''loose'' pools and other multilateral coordination arrangements, and holding companies. Even between the categories of tight and loose pools, however, there is no bright dividing line.

[416] A technical conference on pro forma tariffs was held on October 27, 1995. A technical conference on power pools was held on December 5 and 6, 1995 and a follow-up technical conference on ISOs and power pools was held on January 24, 1996.

accomplishing comparable access.[417] We recognize that several utilities are exploring the possibility of forming ISOs. For example, discussions are ongoing in California, PJM, NYPP, and the Midwest. Therefore, because of the industry's interest (which we share) in the concept of an ISO and the potential for an ISO to provide non-discriminatory transmission services to all market participants, we will provide guidance in this section on minimum ISO characteristics.

1. Tight Power Pools

For purposes of this Rule, the tight power pools are: New York Power Pool (NYPP), New England Power Pool (NEPOOL), Pennsylvania-New Jersey-Maryland Interconnection (PJM), and the Michigan Electric Coordinated Systems (MECS).

Public utilities who are members of a tight pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) An individual Final Rule pro forma tariff; or (2) a joint pool-wide Final Rule pro forma tariff. They are not required to take service for *pool transactions* under the tariff that is filed within 60 days. However, they will be required to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and must begin to take service under that tariff for all pool transactions no later than December 31, 1996. The purpose of this extension is to allow sufficient time for tight pools to amend their pooling agreements and to restructure their operations to conform to the requirements of the Final Rule. We also believe that the additional time is necessary to preserve efficient trading arrangements during the restructuring period.

The Commission therefore will require that the public utility members of tight pools file reformed power pooling agreements no later than December 31, 1996. The reformed power pool agreements should establish open, non-discriminatory membership provisions (including establishment of an ISO, if that is a pool's preferred method of remedying undue discrimination) and modify any provisions that are unduly discriminatory or preferential. The membership provision must allow any bulk power market participant to join, regardless of the type of entity, affiliation, or geographic location.

If the reformed agreement allows members to make transmission commitments or contributions in exchange for the discounted transmission rates, the pool may file a transmission tariff that contains an access fee for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs. Alternatively, the pool could make available a transmission rate that is structured the same as the discounted rate (*e.g.,* non-pancaked) but with a higher rate that is justified on the basis of transmission-related costs borne (or contributed) by the pool members. However, any such access fee or higher rate must be justified solely on the basis of transmission costs and cannot be tied to the costs of any other agreement among the pool members (*e.g.,* generation reserve sharing).

2. Loose Pools

For purposes of the Final Rule, a loose pool is any multi-lateral (more than 2 public utilities) arrangement, many of which contain discounted and/or special transmission arrangements. Examples are MAPP, Inland Power Pool, and the MOKAN pool. Other entities may qualify to be treated as a loose pool if they can show that they meet the definition above.

Public utilities within a loose pool must file, within 60 days of publication of the Final Rule in the Federal Register, either: (1) An individual Final Rule pro forma tariff; or (2) a pool-wide Final Rule pro forma tariff. They are not required to take service for *pool transactions* under the tariff that is filed within 60 days. However, they will be required to file a joint pool-wide Final Rule pro forma tariff no later than December 31, 1996, and must begin to take service under that tariff for all pool transactions no later than December 31, 1996. The purpose of this extension is to allow sufficient time for loose pools to amend their agreements and to restructure their operations to conform to the requirements of the Final Rule. We also believe that the additional time is necessary to preserve efficient trading arrangements during the restructuring period.

The Commission therefore will require that the public utility members of loose pools file reformed power pooling agreements no later than December 31, 1996. They also must file a joint pool-wide tariff no later than December 31, 1996. The reformed power pool agreements should establish open, non-discriminatory membership provisions and modify any provisions that are unduly discriminatory or preferential. The membership provision must allow any bulk power market participant to join, regardless of the type of entity, affiliation, or geographic location.

The Commission recognizes that loose pools typically do not operate as a single control area and that operational unbundling, perhaps through an ISO, might not be readily attainable at this time. Nonetheless, we encourage the members of loose pools to explore the advantages of the ISO concept.

If the reformed agreement allows members to make transmission commitments or contributions in exchange for discounted transmission rates, the pool may file a transmission tariff that contains an access fee for non-transmission owning members or non-members, justified solely on the basis of transmission-related costs. Alternatively, the pool could make available a transmission rate that is structured the same as the discounted rate (*e.g.,* non-pancaked) but with a higher rate that is justified on the basis of transmission-related costs borne (or contributed) by the pool members. However, any such access fee or higher rate must be justified solely on the basis of transmission costs and cannot be tied to the costs of any other agreement among the pool members (*e.g.,* generation reserve sharing).

3. Public Utility Holding Companies

Public utility members of registered and exempt holding companies that are also members of tight or loose pools are subject to the tight and loose pool requirements set forth above. The remaining holding company public utility members, with the exception of the Central and South West (CSW) System, are required to file a single system-wide Final Rule pro forma tariff permitting transmission service across the entire holding company system at a single price within 60 days of publication of the Final Rule in the Federal Register (service companies may, of course, file on behalf of their public utility affiliates). As discussed below, CSW presents special circumstances.

The CSW System is comprised of four operating public utilities. Two of those utilities, Southwestern Electric Power Company (SWEPCO) and Public Service Company of Oklahoma (PSO) operate in the Southwest Power Pool (SPP). The other two, West Texas Utilities Company (West Texas) and Central Power and Light Company (CP&L), operate in the Electric Reliability

[417] The DOJ and DOE suggested that the Commission examine operational unbundling as a way of enforcing comparability in transmission service. DOJ and DOE believe that functional unbundling may not be adequate to ensure comparability and so have recommended that some form of operational unbundling be required. While we believe that requiring this is premature, we note that an ISO is one way to achieve operational unbundling and we encourage the voluntary development of ISOs.

Council of Texas (ERCOT). SWEPCO and PSO exchange power with West Texas and CP&L through two high voltage, direct current interconnections (the North and East Interconnections).[418]

Pursuant to the Commission orders concerning the North and East Interconnections, CP&L, West Texas, SWEPCO, and PSO have on file what are referred to as the ''to or from and over tariffs.'' [419] Those tariffs apply only to transmission service that involves the delivery of power and energy to or from and over the North and East Interconnections.[420] The tariffs do not apply to the transmission of power for CSW subsidiaries other than the operating companies. The tariffs in many respects are different from the Final Rule pro forma tariff and do not provide comparable services. Moreover, the pricing provided in the ''to or from and over'' tariffs is different from the pricing set forth in the Texas Commission's final open access rule.[421]

Given these special circumstances, we believe it appropriate to give CSW the opportunity to propose a solution to achieving comparability for the CSW system. Accordingly, we direct the public utility subsidiaries of CSW to consult with the Texas, Arkansas, Oklahoma and Louisiana Commissions and to file not later than December 31, 1996 a system tariff that will provide comparable service to all wholesale users on the CSW System,[422] regardless of whether they take transmission service wholly within ERCOT or the SPP, or take transmission service between the reliability councils over the North and East Interconnections.[423]

The Commission will give public utilities that are members of holding companies an extension of the requirement to take service under the system tariff *for wholesale trades* between and among the public utility operating companies within the holding company system. This extension is until December 31, 1996—the same extension we are granting to power pools. At that point, the public utility operating companies will be required to take service under the Final Rule pro forma tariff for wholesale trades among themselves. In addition, it may be necessary for registered holding companies to reform their holding company equalization agreement to recognize the non-discriminatory terms and conditions of transmission service required under the Final Rule pro forma tariff.

4. Bilateral Coordination Arrangements

Any bilateral wholesale coordination agreement executed after the effective date of this Rule will be subject to the functional unbundling and open access requirements set forth in this Rule. With regard to existing bilateral agreements, however, the diversity of the types of agreements currently on file presents special implementation problems. The Commission is particularly concerned with future economy energy transactions that may occur pursuant to existing umbrella-type coordination agreements. Accordingly, we shall require all bilateral economy energy coordination contracts executed before the effective date of this Rule to be modified to require unbundling of any economy energy *transaction* occurring after December 31, 1996. All non-economy energy bilateral coordination contracts executed before the effective date of this Rule will be permitted to continue in effect, but will be subject to complaints filed under section 206 of the FPA. Under those procedures, the rates, terms, and conditions of individual coordination contracts may be challenged as unduly discriminatory or otherwise unlawful.

To compute the unbundled coordination compliance rate, the utility must subtract the corresponding transmission unit charge in its open access tariff from the existing coordination rate ceiling. For example, if a utility has a coordination rate ceiling for hourly service of incremental cost plus 15 mills/kWh and a transmission tariff rate for hourly service of 3 mills/kWh, it shall revise the coordination rate ceiling to incremental cost plus 12 mills/kWh. The Commission cautions that the compliance filing will be strictly limited to removing the current transmission tariff price from the coordination price and will not be a medium for otherwise revising the residual coordination sales price.

The transmission rate for the coordination transactions may be at or below the tariff rate. However, if a utility's transmission operator offers a discounted transmission rate to the utility's wholesale marketing department or an affiliate for the purposes of coordination transactions, the same discounted rate must be offered to others for trades with any party to the coordination agreement. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory.[424] This may require parties to file modifications of the coordination arrangements.

ISO Principles

The Commission recognizes that some utilities are exploring the concept of an Independent System Operator and that the tight power pools are considering restructuring proposals that involve an ISO. While the Commission is not requiring any utility to form an ISO at this time, we wish to encourage the formation of properly-structured ISOs. To this end, we believe it is important to give the industry some guidance on ISOs at this time. Accordingly, we here set out certain principles that will be used in assessing ISO proposals that may be submitted to the Commission in the future.

These principles are applicable only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools. We recognize that some utilities are exploring concepts that do not involve full operational control of the grid. Without in any way prejudging the merits of such arrangements, the following principles do not apply to independent administrators or coordinators that lack operational control. We do not have enough information at this time to offer guidance about such entities, but

[418] The North and East Interconnections were ordered by the Commission pursuant to sections 210, 211 and 212 of the Federal Power Act. *See* Central Power and Light Company, *et al.*, 17 FERC ¶ 61,078 (1981), *order on reh'g*, 18 FERC ¶ 61,100 (1982); 40 FERC ¶ 61,077 (1987).

[419] Houston Lighting and Power Company (HL&P) and Texas Utilities Electric Company (TU) also have on file ''to or from and over tariffs'' pursuant to the Commission orders.

[420] *See, e.g.*, CP&L and West Texas Interpool Transmission Service Tariff, § 4.1.

[421] *Compare* 21 TEX REG 1397, LEXIS, *mimeo* at 18 (adopting hybrid pricing scheme with 70% of transmission rate based on regional postage stamp method and 30% based on the vector-absolute megawatt-mile method) *with Id.* at Article III.

We note that the Texas Commission concluded that the ERCOT portion of the costs of the North and East Interconnections ''should be included in the cost of service, when the owners of the (Interconnections) amend the FERC tariffs for the use of the (Interconnections) to provide equal access to other utilities. 21 TEX REG, LEXIS, *mimeo* at 24.

[422] It may be appropriate to have different rates for transmission service wholly within ERCOT or the SPP, and for service between the reliability councils. However, the same rates, terms, and conditions applicable for third parties should also be applicable to the CSW System's wholesale transmission requirements.

[423] We recognize that this action may require amendment to the Commission's orders under FPA sections 210, 211, and 212, ordering the North and East Interconnections. In this regard, it should be clearly understood that the Commission's action in requiring comparable service by the CSW System is not in any way intended to result in public utility status to any ERCOT participants that are not public utilities—*e.g.*, HL&P and TU. *See* 16 U.S.C. 824(b)(2).

[424] All discounts must be posted on the transmission provider's OASIS.

recognize that they could perform a useful role in a restructured industry.

Because an ISO will be a public utility subject to our jurisdiction,[425] the ISO's operating standards and procedures must be approved by the Commission. In addition, a properly constituted ISO is a means by which public utilities can comply with the Commission's non-discriminatory transmission tariff requirements. The principles for ISOs are:

1. The ISO's governance should be structured in a fair and non-discriminatory manner. The primary purpose of an ISO is to ensure fair and non-discriminatory access to transmission services and ancillary services for all users of the system. As such, an ISO should be independent of any individual market participant or any one class of participants (e.g., transmission owners or end-users). A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO's rules of governance, however, should prevent control, and appearance of control, of decision-making by any class of participants.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards. To be truly independent, an ISO cannot be owned by any market participant. We recognize that transmission owners need to be able to hold the ISO accountable in its fiduciary role, but should not be able to dictate day-to-day operational matters. Employees of the ISO should also be financially independent of market participants. We recognize, however, that a short transition period (we believe 6 months would be adequate) will be needed for employees of a newly formed ISO to sever all ties with former transmission owners and to make appropriate arrangements for pension plans, health programs and so on. In addition, an ISO should not undertake any contractual arrangement with generation or transmission owners or transmission users that is not at arm's length. In order to ensure independence, a strict conflict of interest standard should be adopted and enforced.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner. An ISO should be responsible for ensuring that all users have non-discriminatory access to the transmission system and all services under ISO control. The portion of the transmission grid operated by a single ISO should be as large as possible, consistent with the agreement of market participants, and the ISO should schedule all transmission on the portion of the grid it controls. An ISO should have clear tariffs for services that neither favor nor disfavor any user or class of users.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council. Reliability and security of the transmission system are critical functions for a system operator. As part of this responsibility an ISO should oversee all maintenance of the transmission facilities under its control, including any day-to-day maintenance contracted to be performed by others. An ISO may also have a role with respect to reliability planning. In any case, the ISO should be responsible for ensuring that services (for all users, including new users) can be provided reliably, and for developing and implementing policies related to curtailment to ensure the on-going reliability and security of the system.

5. An ISO should have control over the operation of interconnected transmission facilities within its region. An ISO is an operator of a designated set of transmission facilities.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading. A key function of an ISO will be to accommodate transactions made in a free and competitive market while remaining at arm's length from those transactions. The ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading over interfaces in some circumstances. It is important that the ISO's operational control be exercised in accordance with the trading rules established by the governing body. The trading rules should promote efficiency in the marketplace. In addition, we would expect that an ISO would provide, or cause to be provided, the ancillary services described in this Rule.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market. Management and administration of the ISO should be carried out in an efficient manner. In addition to personnel and administrative functions, an ISO could perform certain operational functions, such as: determination of appropriate system expansions, transmission maintenance, administering transmission contracts, operation of a settlements system, and operation of an energy auction. The ISO should use competitive procurement, to the extent possible, for all services provided by the ISO that are needed to operate the system. All procedures and protocols should be publicly available.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions. Appropriate price signals are essential to achieve efficient investment in generation and transmission and consumption of energy. The pricing policies pursued by the ISO should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid. In particular, the Commission would consider transmission pricing proposals for addressing network congestion that are consistent with our Transmission Pricing Policy Statement. In addition, an ISO should conduct such studies and coordinate with market participants including RTGs, as may be necessary to identify transmission constraints on its system, loop flow impacts between its system and neighboring systems, and other factors that might affect system operation or expansion.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements. A free-flow

[425] A public utility is any person that owns *or operates* facilities used for the transmission of electric energy in interstate commerce or the sale of electric energy at wholesale in interstate commerce. An ISO will operate facilities used for the transmission of electric energy in interstate commerce and thus will be subject to the Open Access and OASIS rules.

of information between the ISO and market participants is required for an ISO to perform its functions and for market participants to efficiently participate in the market. At a minimum, information on system operation, conditions, available capacity and constraints, and all contracts or other service arrangements of the ISO should be made publicly available. This information should be made available on an OASIS operated by the ISO.

10. An ISO should develop mechanisms to coordinate with neighboring control areas. An ISO will be required to coordinate power scheduling with other entities operating transmission systems. Such coordination is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and stability of the systems. The mechanisms by which ISOs and other transmission operators coordinate can be left to those parties to determine.

11. An ISO should establish an ADR process to resolve disputes in the first instance. An ISO should provide for a voluntary dispute resolution process that allows parties to resolve technical, financial, and other issues without resort to filing complaints at the Commission. We would encourage the ISO to establish rules and procedures to implement alternative dispute resolution processes.

G. Pro Forma Tariff

In the NOPR, the Commission stated that—

> all utilities use their own systems in two basic ways: to provide themselves point-to-point transmission service that supports coordination sales, and to provide themselves network transmission service that supports the economic dispatch of their own generation units and purchased power resources (integrating their resources to meet their internal loads). [426]

Accordingly, the Commission proposed two pro forma tariffs in Appendices B and C of the NOPR: One for point-to-point service and one for network service. Our goal was to encourage the development of competitive bulk power markets by ensuring that all participants would be able to secure transmission services on a non-discriminatory basis. We attempted in the NOPR pro forma tariffs to articulate the minimally acceptable terms and conditions of service for point-to-point and network transmission service that were required to ensure non-discriminatory transmission service.[427] We explained that, for the most part, specific pricing provisions were omitted. We asked for comments on whether these tariffs provided a good basis for defining the minimum acceptable non-price terms and conditions of service.[428]

Subsequently, in a June 28, 1995 order, we encouraged public utilities to file open access transmission tariffs as soon as possible.[429] Tariffs with terms and conditions of service substantively similar to the NOPR pro forma tariffs would become effective without a refund condition, assuming there were no other concerns, *e.g.*, rate issues. We also indicated that these tariffs would be subject to revision based on the Final Rule.

Unified Pro Forma Tariff

The Commission received many comments on both the point-to-point and network tariffs. Many commenters suggested improvements to the proposed tariffs. Others took issue with how to reconcile various aspects of service under the two tariffs (*e.g.*, cost allocation, service priority, customer rights and obligations). As discussed below, the Commission has attempted to address these concerns in developing tariff requirements for the Final Rule. Importantly, while the Commission has retained point-to-point transmission service and network transmission service as distinct services, the requirements for the two services are now in a single pro forma tariff.[430] The Final Rule pro forma tariff eliminates many of the differences between the two NOPR pro forma tariffs, provides a unified set of definitions, and consolidates certain common requirements such as the obligation to provide ancillary services. The general terms and conditions of transmission service specified in the Final Rule pro forma tariff should be familiar to all utilities, particularly those that have voluntarily filed open access tariffs based on the NOPR pro forma tariffs.

The Commission believes that the modified, single pro forma tariff, in conjunction with the other requirements, is sufficient to remedy undue discrimination in the provision of transmission services. However, we note that in an accompanying notice of proposed rulemaking in Docket No. RM96–11–000, we are seeking comments on whether a different form of open access tariff—one based solely on a capacity reservation system—might better accommodate competitive changes occurring in the industry while ensuring that all wholesale transmission service is provided in a fair and non-discriminatory manner.

We address below the comments received on the NOPR tariff and the specific modifications we have made in the Final Rule pro forma tariff.

1. Tariff Provisions That Affect The Pricing Mechanism

a. Non-Price Terms and Conditions

Comments

Utilities For Improved Transition argues that any generic imposition of detailed tariffs on the electric industry will stifle the evolution of the industry. Rather, it asserts, utilities that supply transmission service should be permitted to apply general principles of comparability in their company-specific tariffs, using terms and conditions of service based on their own particular circumstances and those of their customers.

Utility Working Group wants the final rule to allow utilities to depart from the pricing method implicitly contained in the NOPR pro forma tariffs. It argues that the final rule should recognize that some terms and conditions may not make sense in the context of innovative pricing proposals.

DOE thinks that it is proper to base the tariffs on a familiar and simple pricing method. However, DOE suggests that, in the future, the Commission carefully assess the workability of the contract path model in a competitive bulk power market. DOE suggests that spot or real-time pricing should be considered.

Numerous commenters contend that the NOPR pro forma tariffs are based upon the contract path, embedded cost methodology. According to EEI and other IOU commenters, conforming changes may be needed to various terms and conditions of the tariffs to implement pricing methodologies that are not based upon contract path. These commenters argue that any flow-based model would necessitate different non-price terms and conditions. The commenters generally recognize the technical difficulties of implementing a flow-based model.[431] These commenters assert that the NOPR pro forma tariffs, as written, are not independent of pricing.

EGA criticizes the assumption underlying the contract path approach,

[426] FERC Stats. & Regs. ¶ 32,514 at 33,079.

[427] *Id.* at 33,092.

[428] On October 27, 1995, the Commission's staff sponsored a technical conference on the pro forma tariffs.

[429] American Electric Power Service Corporation, *et al.*, 71 FERC ¶ 61,393, modified, 72 FERC ¶ 61,287 (1995).

[430] The Final Rule pro forma tariff is attached as Appendix D.

[431] Additional comments concerning transition to flow-based pricing are summarized in Section IV.A.6.

i.e., that the capacities of individual transmission paths can be determined independently and made available to third parties. EGA notes that, in light of the competitive implications associated with transmission pricing, some utilities may propose other non-price terms and conditions suitable for other pricing methods, including power-flow-based tariffs. EGA expresses concern that the pro forma tariffs will be the only type of tariff allowed. EGA believes that the Commission should follow its transmission pricing policy guidelines and not impose a special burden on parties proposing tariffs that differ from the final rule pro forma tariffs, including non-price terms that support alternative pricing methods.

Some commenters also interpret the lack of reference to opportunity cost and incremental cost in the NOPR pro forma tariffs as a rejection of their use.[432]

Commission Conclusion

We agree that non-price terms and conditions cannot be designed independent of pricing and cost recovery. As discussed in detail below, the Final Rule pro forma tariff is intended to *initiate* open access, with non-price terms and conditions based on the contract path model of power flows and embedded cost ratemaking. It is designed based on the practices and procedures currently used by virtually all public utilities and complements the large number of tariffs already filed with the Commission. The Final Rule pro forma tariff is not intended to signal a preference for contract path/embedded cost pricing for the future. We recognize that the industry, in response to changes in institutions, competitive pressure, and technological innovations, is evolving rapidly. For example, various forms of flow-based pricing are beginning to be considered in conjunction with electronic transmission information systems. We seek to encourage this process and will in the future entertain non-discriminatory tariff innovations to accommodate new pricing proposals.[433]

In response to various comments, we are revising certain non-price terms and conditions where suggested changes either improve the tariff services or reconcile tariff inconsistencies. The nature of these tariff revisions does not appear to have serious cost consequences. The mandated changes are generally compatible with the rate proposals already filed by many public utilities. As discussed in Section IV.H., those utilities will not be required to file corresponding rate changes due to our mandated tariff changes to non-price terms and conditions, although they will be permitted to do so.

The Final Rule pro forma tariff includes specific terms and conditions rather than general principles. By initially requiring a standardized tariff,[434] we intend to foster broad access across multiple systems under standardized terms and conditions. However, in response to concerns raised by certain commenters, the tariff provides for certain deviations where it can be demonstrated that unique practices in a geographic region require modifications to the Final Rule pro forma tariff provisions. Accordingly, where applicable, the tariff permits the use of alternative non-price terms or conditions that are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider.

Finally, we will allow utilities to propose a single cost allocation method for network and point-to-point transmission services. These principles, as well as other modifications and clarifications to the NOPR pro forma tariffs, are discussed in detail below.

b. Load Ratio Sharing Allocation Mechanism for Network Service

Comments

Some commenters believe that load ratio cost allocation is appropriate for network service.[435] Other commenters argue that load ratio cost allocation is inappropriate, but disagree on the alternative. They offer a variety of other cost allocation and pricing methods.

The most frequent comment is that network and point-to-point services should be priced on the same basis. Florida Power Corp wants network contract demand to be offered and priced on a 12 CP basis.[436] ConEd and Duke argue that their systems are built and designed to meet a single peak; therefore, they contend that network service costs should be allocated with a load ratio calculation based on annual system peak rather than 12 CP. PSE&G claims that load ratio cost allocation works only if the customer has its own generation. Many commenters propose that ‘‘behind the meter’’ generation and load be eliminated from the network load ratio calculation.[437]

CINergy notes that the transmission provider's monthly load ratio calculation includes its long-term off-system firm service. It proposes that off-system sales be eliminated from the load ratio calculation to enable the transmission provider to offer discounts on long-term service. Alternatively, CINergy proposes that the revenues from these long-term off-system sales be shared with network customers based on their load ratio.

Atlantic City and Allegheny contend that cost allocation for network service should also reflect customers' relative energy use (*i.e.*, not just customers' coincident demand). Consequently, these commenters propose that cost allocation consider the network customer's actual load factor. Allegheny also proposes adding a minimum revenue provision to the load ratio method to recognize cost responsibility for non-peak use. Allegheny further proposes to include an increasing return on equity as available transmission capacity decreases. EEI proposes that cost allocation be based on a customer's non-coincident peak demand.

Lower Colorado River Authority proposes using load flow studies to determine planned use during the system peak with MW-mile billing units. It believes that this pricing method should be used for all transmission service to ensure comparable transmission pricing. Oklahoma G&E wants cost allocation to be based on the impacted MW-mile method, or alternatively, to determine embedded cost by voltage level. Centerior proposes the use of actual transfer capability instead of contract path capability in determining cost responsibility.

Orange & Rockland recommends some form of a ‘‘poolco’’ approach using locational marginal cost pricing. DOE also recommends using location-specific spot pricing (a form of marginal cost) for operating and congestion costs.

Public Generating Pool believes that load ratio share pricing is unworkable in the Pacific Northwest, in part because generation is generally located outside of the control area directly served by parties in the Northwest, and in part because BPA, which does not have a typical service territory, dominates the regional transmission market. Seattle states that cost allocation based solely on demand is inappropriate for systems

[432] *E.g.,* BPA, Utilities For Improved Transition, PG&E, Duke.

[433] We further clarify that, contrary to some commenters' interpretation, the Final Rule pro forma tariff is in no way a rejection of opportunity or incremental cost pricing.

[434] As noted in Section IV.H., public utilities may propose variations that are consistent with or superior to the terms and conditions in the Final Rule pro forma tariff.

[435] *E.g.,* PSNM, WP&L.

[436] Florida Power Corp's contract demand proposal would allow a network customer to nominate less than its full load for transmission service.

[437] *E.g.,* Cajun, NRECA.

that consist predominantly of hydro generation.[438]

AEC & SMEPA and NRECA are concerned about pancaked rates for network service that is provided to load served by more than one network tariff. Other commenters advocate use of some form of regional pricing.[439] American Wind proposes the use of a complex seasonal calculation, which appears to benefit wind energy. NY Com and Missouri-Kansas Industrials also express a preference for seasonal pricing models.

Commission Conclusion

We conclude that the load ratio allocation method of pricing network service continues to be reasonable for purposes of initiating open access transmission. Network service permits a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning. Moreover, we recognize that alternative allocation proposals may have merit and welcome their submittal by utilities in future rate applications. They will be evaluated on a case-by-case basis and decided on their merits.

As to the concerns raised by AEC & SMEPA and NRECA about pancaked rates for network service provided to load served by more than one network service provider, we have stated that if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so.[440] Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by ''behind the meter'' generation that seek to eliminate the load from their network load ratio calculation.

As noted, the most frequent comment is that the network and point-to-point services should be priced on a similar basis. This concern is addressed in the next section.

c. Annual System Peak Pricing for Flexible Point-to-Point Service

Comments

Commenters express concern that, if annual system peak capability is used to determine rates for point-to-point service and 12 CP is used to allocate costs for network service, point-to-point service may be underpriced relative to network service.[441] Therefore, many commenters propose pricing both services on the same basis.

EEI argues that flexible point-to-point service provides a premium service at a discount price. Therefore, EEI would increase the price unless the Commission either (1) eliminates the flexibility or (2) allows network customers to make non-firm sales at no additional charge. It recommends use of 12 CP for pricing both network and point-to-point service, but would credit point-to-point revenues to the cost of service for network and native load to avoid over-collection from contract demand point-to-point users. Alternatively, EEI contends that point-to-point service could use annual system peak capability pricing with a ratchet,[442] although EEI believes that 12 CP reflects the premium nature of long-term transmission. Under this alternative method, EEI notes that long-term non-flexible point-to-point service would use annual system peak pricing, while short-term service should be based on ''up to'' (ceiling) rates. In essence, EEI proposes a two-tier point-to-point service, with the first tier (flexible service) of equal priority in all respects to network service.[443] Ohio Edison also claims that, as proposed, flexible point-to-point service is a more valuable service than network service because it would be priced lower than network service. To correct for this difference, Ohio Edison would impose a separate rate for point-to-point non-firm use.

According to NRECA, unless the same measure of demand is included in the calculation of network and point-to-point charges, actual revenue from these two firm services will be greater than the actual cost of service. FL Com believes that flexible point-to-point service allows a transmission customer to engage in network economy transactions without incurring a full network charge, thus gaining an advantage over the transmission provider. Atlantic City recommends that the Commission either (1) eliminate the flexibility of point-to-point service or (2) price such service on a 12 CP basis. It claims that the use of an annual system peak capability creates a higher value service at a lower cost than network service. Based on its 1994 system data, Atlantic City claims that there is a 33 percent difference in rates between network and point-to-point services. Atlantic City also opposes the requirement to offer point-to-point service on an hourly basis, claiming that, unlike the point-to-point service customer, native load and network service customers are responsible for system investment year-round. Atlantic City also argues that point-to-point customers should pay for all non-firm use, *i.e.*, the Commission should eliminate the flexible nature of firm point-to-point service. PSE&G argues that point-to-point service should be used only for through-flow or out-flow transactions with all other transactions treated as network service. Thus, according to PSE&G, point-to-point service would not need flexibility.

If an annual system peak capability is used, Oklahoma G&E would redefine point-to-point service to eliminate the flexibility. FPL recommends either eliminating the flexibility to nominate secondary receipt and delivery points and receive non-firm service between them or pricing point-to-point service as premium service (*i.e.*, at a higher price than network service). Florida Power Corp claims that flexibility should be associated with network service, not point-to-point service. It also argues that revenues from point-to-point service should be credited against total transmission costs. It would similarly exclude point-to-point demands from the derivation of the network rate. Utility Working Group claims that if flexible point-to-point service is retained, such service should be priced at a higher (unspecified) rate or the non-firm secondary use should be separately priced. It believes that all users should

[438] Additional comments concerning the Pacific Northwest are summarized in Section IV.K.

[439] *E.g.*, OH Coops, Municipal Energy Agency Nebraska, UT Com.

[440] Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 (1996), *reh'g pending.*

[441] Under the annual system peak method, system costs are allocated on the basis of each customer's contribution to the utility's annual system peak. Under the 12 CP method, system costs are allocated based on the average of the customer's usage at the time of the utility's 12 monthly system peaks.

[442] A ratchet is a billing provision that imposes minimum payment obligations on utility customers.

[443] *See also* Centerior, SCE&G, Detroit Edison.

pay for non-firm use, or if there is no additional charge under the point-to-point tariff, network customers and the transmission provider should be treated equally. SMUD argues that a user who does not want flexibility should have an option to elect a lower-priced non-flexible point-to-point service.

Commission Conclusion

We agree that pricing both services on a consistent basis may be appropriate. Consequently, we will allow a transmission provider to propose a formula rate that assigns costs consistently to firm point-to-point and network services. While not requiring the use of any particular rate methodology, we will no longer summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks.

Our previous rationale for not using the average of the twelve-monthly peaks as a denominator in the development of non-customer specific transmission rates was enunciated in *Southern Company Services, Inc.*, 61 FERC ¶ 61,339 (1992) (*Southern*). In *Southern*, the Commission was concerned that establishing a system-wide, non-customer specific transmission service rate that did not appropriately account for diversity [444] among various transmission customers might result in the over-recovery of revenues for point-to-point service. Inherent in our ruling in *Southern* was the understanding that once a sufficient pattern of customer usage under the tariff was established, the company was free to file a customer-specific rate using the average of the 12 monthly system peaks for cost allocation. We still believe that it is appropriate for utilities to use a customer-specific allocated cost of service [445] to account for diversity, but based on the changed circumstances since *Southern* (which we discuss below) we will now permit an alternative.

We also note that the circumstances in *Southern* are distinguishable from those now present in the industry. Southern proposed a rigid, inflexible firm point-to-point transmission service where the customer paid separately for each delivery and receipt point combination. The only flexibility permitted was to use alternative receipt and delivery points on a non-firm basis at no additional charge. As the name implies, the flexible nature of the point-to-point transmission service proposed in the NOPR is more akin to the service provided to native load and network service customers. Contrary to what was proposed in *Southern*, point-to-point service does not require separate charges for each firm service receipt and delivery point combination. Rather, customers pay on the basis of the higher of the total delivery points or total receipt point combination. Flexible point-to-point transmission customers continue to be able to access alternative receipt and delivery points on a non-firm basis without additional charges (as long as they remain within their capacity reservation). In addition, firm point-to-point customers can reassign and resell unused portions of their reserved firm capacity to third parties. With flexible firm and non-firm point-to-point transmission service, the transmission provider must make firm point-to-point transmission capacity available to the customer regardless of its load characteristics or use.

For these reasons, we will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads. The adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with *all* firm point-to-point service customers plus the monthly contract demand reservations for *all* firm point-to-point service.

The flexibility and reassignment rights of this transmission service require the transmission provider to hold the firm contract capacity available regardless of the customer's own load characteristics or its actual use. In other words, a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes.

In order to prevent over-recovery of costs for those who use this approach, we will require transmission providers to include firm point-to-point capacity reservations in the derivation of their load ratio calculations for billings under network service. In addition, revenue from non-firm services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates. The combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement.[446]

d. Opportunity Cost Pricing

(1) Recovery of Opportunity Costs

Comments

EEI and IOUs generally support the notion that transmission customers should pay some form of opportunity cost when transmission is constrained and request that the final rule clearly define redispatch and opportunity costs. These commenters generally agree that the final rule should codify these terms consistent with recent Commission orders addressing opportunity costs.

Duke requests that the final rule clarify that the transmission customer should pay all the opportunity costs associated with modified dispatch. Centerior argues that redispatch costs include consideration of parallel flows and scheduled deliveries, which, according to Centerior, cause redispatch costs to be incurred.

Florida Power Corp and NYSEG state that redispatch costs should be either rolled in or charged on an incremental basis, consistent with the Commission's "or" pricing policy. Florida Power Corp recommends that an opportunity cost recovery provision be added to the "Rates and Charges" sections of the tariffs. NYSEG recommends that the tariffs implement the Commission's recent ruling in *Florida Power & Light Company*, 66 FERC ¶ 61,227 (1994), allowing lost opportunity costs to be recalculated annually. NYSEG believes that: (1) Redispatch costs should be collected for any period in which the transmission customer causes a constraint, including the period of time it takes to construct incremental facilities necessary to alleviate the constraint; (2) network customers should be responsible for any opportunity costs incurred as a result of their non-firm use of the system if such costs rise to a level above their load ratio share of system costs; and (3) point-to-point customers should be responsible for any opportunity costs incurred as a result of their non-firm use of the transmission provider's system up to their reserved firm entitlement.

Ohio Edison believes that, given the unique nature of network service, it is inappropriate to require network service customers to incur redispatch costs in order to create additional capacity. PECO requests that the final rule clearly indicate (1) from whose perspective

[444] In this context, diversity occurs when a customer's peak demand is not coincident with the transmission provider's system peak demand.

[445] The use of this rate design is particularly applicable where customers who were taking bundled service convert to transmission-only service under the point-to-point tariff and ensures that transmission costs are allocated to point-to-point customers and network customers in a consistent manner.

[446] FERC Stats. & Regs. ¶ 31,005 (1994).

''least cost'' redispatch is judged and (2) that the ''least cost'' redispatch obligation is subordinate to reliability.

Concerned that transmission providers could manipulate the calculation of redispatch charges to increase profits, NRECA proposes that transmission providers develop formal redispatch protocols that would be provided to all customers. NRECA argues that all information necessary to calculate redispatch costs should be made available on the RIN. Customers assessed redispatch charges should be provided with all the necessary information to evaluate such charges, including full audit rights. NRECA, Cajun, and PacifiCorp object to the inclusion of ''lost opportunity'' costs in redispatch charges. NRECA proposes that only actual non-firm sales or purchases should be included in the calculation of opportunity costs.

United Illuminating and Seattle state that all opportunity costs should be assessed to short-term and non-firm transmission service customers that cause the transmission provider to redispatch its generation to unload a constrained transmission line. According to United Illuminating, it is not appropriate to roll opportunity costs into the rates charged other transmission users because existing users do not have the choice to pay the opportunity costs or to allow their transaction to be curtailed.

UtiliCorp, on the other hand, states that all ''out of rate'' uneconomic dispatch costs should be rolled in and recovered from all users of the transmission system. UtiliCorp argues that directly assessing these costs to a particular customer would unfairly penalize a customer who could not gain access to a system until after the tariffs take effect.

CCEM argues that only lost opportunity costs associated with the loss of *firm* purchases or sales should be recoverable. CCEM also believes that the transmission provider should calculate the redispatch costs in advance and transmission customers should be able to opt out of redispatch if costs rise above a certain level.

Commission Conclusion

We will retain redispatch provisions in the Final Rule pro forma tariff, but clarify that redispatch is required only if it can be achieved while maintaining reliable operation of the transmission system in accordance with prudent utility practice.

We find that the recovery of redispatch cost requires that: (1) A formal redispatch protocol must be developed and made available to all customers; and (2) all information necessary to calculate redispatch costs should be made available to the customer for audit.

As discussed in the Section IV.H., the Commission is according substantial flexibility to public utilities to propose appropriate pricing terms, including opportunity cost pricing, in their compliance tariff. However, as with any compliance filing, the rates proposed must meet the standards for conforming proposals in the Transmission Pricing Policy Statement.

In *Northeast Utilities* and *Penelec,* we fully explained our rationale for allowing utilities to charge opportunity costs.[447] We concluded that a public utility is entitled to full compensation for all ''legitimate'' and ''verifiable'' costs it incurs to provide firm transmission service.[448] We explained that where a utility can demonstrate that additional opportunity costs are incurred as a direct result of providing transmission service, our pricing principles would permit recovery of those costs. The Commission further explained in the Transmission Pricing Policy Statement that when transmission capacity is constrained and a utility does not expand capacity, we have allowed the utility to charge transmission customers the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two (*i.e.,* ''or'' pricing is permitted; ''and'' pricing is not). The opportunity costs are capped by incremental expansion costs.[449]

Transmission providers proposing to recover opportunity costs must adhere to the following requirements:

(1) A fully developed formula describing the derivation of opportunity costs must be attached as an appendix to their proposed tariff.

(2) Proposals must address how they will be consistent with comparability.

(3) All information necessary to calculate and verify opportunity costs must be made available to the transmission customer.

[447] Northeast Utilities Service Company (*Northeast Utilities*), 56 FERC ¶ 61,269 (1991), *order on reh'g,* 58 FERC ¶ 61,070, *reh'g denied,* 59 FERC ¶ 61,042 (1992), *order granting motion to vacate and dismissing request for rehearing,* 59 FERC ¶ 61,089 (1992), *aff'd in relevant part and remanded in part,* Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993); Pennsylvania Electric Company (*Penelec*), 58 FERC ¶ 61,278 at 62,871–75, *reh'g denied,* 60 FERC ¶ 61,034 (1992), *affd,* Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

[448] *Penelec,* 58 FERC at 61,872; 60 FERC ¶ 61,034 at 61,126 (1992).

[449] FERC Stats. & Regs. ¶ 31,005 at 31,138.

(2) Fuel Adjustment Clause Treatment for Redispatch Costs

If the transmission provider proposes to separately collect redispatch costs on a direct assignment basis from a specific transmission customer, we will require that the transmission provider credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause.

e. Expansion Costs

Comments

ELCON argues that direct assignment of 100% of the costs of expanding a constrained transmission system to a particular customer is unfair. NY Energy Buyers believes that the costs of expanding the transmission system should be shared among all customers seeking transmission service. Alternatively, NY Energy Buyers states that if direct assignment of system expansions is adopted, such costs should be payable both by new wholesale customers and by new retail load. According to NY Energy Buyers, it would be preferable for the utility to treat all requesters during a given period as making one request for a large increment of capacity, with all requesters paying the same average incremental cost. New native load also should be considered to be a requester of transmission capacity and allocated an appropriate share of any expansion costs.

CA Energy Co believes that incremental pricing will discriminate against all later competitors by charging higher rates. It advocates rolled-in pricing with the requirement that all users requesting system expansion commit to service for a term that will cover their proportionate expansion cost assignments.

FPL proposes that costs associated with normal load growth and the repair and/or replacement of older facilities be rolled in with the other embedded transmission costs and shared on a load ratio basis. However, it believes that transmission expansions associated with the addition of a new resource should be separately assigned.

On the other hand, Orange & Rockland maintains that unless expansion costs are directly assigned, an unfair subsidization will occur. According to PECO, transmission customers should be assigned costs for system upgrades under both the network and point-to-point tariffs. Consumers Power claims that the network tariff is unclear about which facilities are directly assignable, and proposes that all costs that exceed the embedded average cost qualify for direct assignment.

SMUD requests that the final rule clarify that if a transmission customer invests in incremental facilities, it will be entitled to ownership-like rights to the capacity addition.

In order to avoid possible argument over the necessity and cost of system expansions for a particular transmission request, NIEP requests that the final rule require utilities to use a ''least-cost'' approach to transmission expansion that includes comparable transmission expansion practices for all wholesale customers.

According to Duke, the concern that the transmission provider's retail customers will retain an advantage by having expansion costs placed on third parties is misplaced. Duke argues that, under ''or'' pricing, the issue of who is responsible for expansion costs would still arise. It contends that the Commission will have to decide on a case-by-case basis whether expansion costs are incurred for the benefit of a specific party or are part of overall network costs. Duke generally supports the current ''or'' pricing policy.

Citing the Commission's Transmission Pricing Policy Statement, FL Com supports the flexibility of charging both embedded cost and incremental cost transmission rates, *i.e.*, ''and'' pricing. It argues that, because of the dynamic and interconnected nature of the transmission system, tariff customers causing expansion costs should be held responsible for both the incremental cost of the addition and some portion of the existing transmission system needed to support the addition. FL Com states that the comparability standard is at odds with the Commission's non-conforming transmission pricing policy, particularly with respect to ''and'' pricing.

Commission Conclusion

Under the Final Rule pro forma tariff, we will allow transmission providers to propose any method of collecting expansion costs that is consistent with our transmission pricing policy. We disagree with ELCON's assertion that directly assigning the costs for expanding a constrained transmission system is necessarily unfair. As we stated in *Northeast Utilities*, if the cost of expansion is directly attributable to a customer's request for transmission service and the expansion would not be undertaken ''but for'' that customer's request, then it is reasonable to assign the cost of expansion to that customer. If we were not to allow the direct assignment of expansion costs to the customer causing the expansion, then other customers would subsidize the new customer's use of the transmission system. We continue to believe that ''or'' pricing sends the proper price signal to customers and promotes efficiency. Under the tariff, any assignment of future expansion costs must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Recovering expansion cost based upon ''and'' pricing will not be allowed.

Any request to recover future expansion costs will require a separate section 205 filing. The Commission will evaluate, on a case-by-case basis, who is responsible for expansion costs in those filings and whether direct assignment of those costs is appropriate.

f. Credit for Customers' Transmission Facilities

Comments

Most commenters agree that the Commission must clearly define when a network customer's transmission facilities warrant a credit from the transmission provider. Several commenters state that customers must bear the burden of demonstrating that their facilities are used by and useful to the transmission provider, provide direct benefits, and support the operation of the transmission system.[450] EEI cautions against providing a credit for facilities that may be integrated with, but of no effective benefit to, the operation of the bulk power system.

The costs associated with customer-owned facilities that are used by the transmission provider should, in PECO's opinion, be recovered from the transmission provider under the customer's own transmission tariff.

FPL cautions that the position of certain parties that transmission facilities warrant a credit if they would have been included in the transmission provider's rates could produce absurd results. It claims that it could actually end up paying a network customer with substantial transmission investment for the right to provide that customer service. FPL contends that it will receive absolutely no service from its network customers because FPL would not need, nor could it use, any of the customers' transmission facilities to integrate FPL's loads and resources. FPL argues that crediting under the so called ''rate base'' test obligates the transmission provider to purchase a load-ratio share of the customer's transmission facilities. FPL states that, under network service, the transmission provider and the network customer will not create a single system.

[450] *E.g.*, EEI, Consumers Power.

AEP recommends that a network customer receive a credit if its transmission facilities meet the following criteria: (1) At points of interconnection, there must be a through-flow of power from the network customer's system to the transmission provider's system under normal operating conditions; and (2) the customer's facilities must: (a) Increase the transfer capability of an interface on the transmission provider's system; (b) provide an alternative path for power flows during transmission facility outages, thus increasing the reliability or stability of the combined system; or (c) otherwise satisfy the transmission provider's planning criteria for the installation of network facilities.

WP&L argues for a broader standard and states that a transmission customer should be entitled to a credit if the transmission owner would have installed similar facilities to provide service for its own native load under similar circumstances. Florida Power Corp states that the credit for each facility should be determined on a case-by-case basis.

PacifiCorp argues that a utility may take advantage of the transmission credit and shift major transmission investment onto another transmitting utility and its transmission customers by simply becoming a network customer. PacifiCorp claims that such a situation may, for example, exist for BPA as a transmitting utility. According to PacifiCorp, preliminary studies indicate at least one potential network customer may be entitled to a transmission credit which would exceed that customer's charges for BPA's network integration service.

APPA, Blue Ridge, and Cajun maintain that a customer's facilities should be evaluated on a basis comparable to the facilities included in the rates of transmission providers in a region. APPA argues that a claim that the transmission customer's facilities do not benefit the transmission system must be weighed against the fact that some facilities included in the transmission provider's rate base may not directly benefit the transmission customer. Cajun advocates setting clear standards for the identification of customer-owned transmission facilities eligible for crediting and clear guidelines for determining the amount of the credit.

SMUD not only supports the credit under the network tariff, but also would extend the credit to facilities used to complete a transaction under the transmission provider's point-to-point tariff.

Commission Conclusion

Because of the diverse concerns raised by the commenters, we are unable to resolve on the basis of this record the extent to which, or under what circumstances, cost credits related to customer-owned facilities would be appropriate under an open-access transmission tariff. We conclude that such credits are more appropriately addressed on a case-by-case basis, where individual claims for credits may be evaluated against a specific set of facts.

We stress that while certain facilities *may* warrant some form of cost credit, the mere fact that transmission customers may own transmission facilities is not a guaranteed entitlement to such a credit. The presumption of many commenters that a customer's subscription to transmission service somehow transforms the provider's and customer's systems into an expanded integrated whole to the mutual benefit of both is not a valid one. As we ruled in *Florida Municipal Power Agency* v. *Florida Power & Light Company* (*FMPA*), it must be *demonstrated* that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider. Specifically, we stated that:

> The integration of facilities into the plans or operations of a transmitting utility is the proper test for cost recognition in such cases. The mere fact that a section 211 requestor has previously constructed facilities is not sufficient to establish a right to credits.[451]

The fact that a transmission customer's facilities may be *interconnected* with a transmission provider's system does not prove that the two systems comprise an *integrated* whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities—a key requirement of integration.[452] We also note that consistent with our ruling in *FMPA*, if a customer wishes not to integrate certain loads and resources, and thereby exclude them from their load ratio share of the allocated cost of the integrated system, it may do so. Customers that elect to do so, however, should recognize that they may need to secure alternative transmission arrangements such as point-to-point transmission service on an as-available basis in order to utilize those resources for reserves.

Where disputes over credits for customer-owned transmission facilities arise, we encourage all parties to first pursue alternative means to resolve their differences rather than seek formal resolution at the Commission. In any event, the Commission anticipates that disputes over the appropriate level of transmission facility credits should not preclude transmission customers from initiating service under the tariff. Where the parties are unable to reach agreement on the appropriate credit for customer-owned transmission facilities, the parties may make an appropriate filing with the Commission.

g. Ceiling Rate for Non-Firm Point-to-Point Service

Comments

Commenters generally support a ceiling rate for non-firm transmission service, capped at the firm rate.[453] Others request clarification as to whether the point-to-point tariff rates are fixed or are ceiling rates. Central Illinois Public Service's major concern is that, if the rates are fixed, the tariffs may result in higher prices for capacity and energy than those currently allowed for bundled service.

NYSEG argues that unequal pricing is a natural phenomenon of the open marketplace and requests assurance that offering transmission service at prices below a cost-based ceiling rate will not expose a transmission provider to claims of undue discrimination.

AEC & SMEPA opposes using the firm rate as the cap for non-firm transmission service. It states that, given the substantially lower quality of non-firm service (with no obligation to plan for such service), no cost-of-service principle justifies charging rates for non-firm service as high as the rate for firm service.

EGA and NRECA state that any discounts from the maximum firm rate must be uniform, transparent, readily understood, and posted on a RIN. According to CCEM and NRECA, the transmitting utility must have nondiscriminatory discount practices and must contemporaneously offer discounts to transmission customers at the same time and on the same basis as discounts for internal sales operations or affiliates.

Commission Conclusion

We believe that it is important to continue to allow pricing flexibility. In accordance with the Commission's current policies, the rate for non-firm point-to-point transmission service may reflect opportunity costs. Any provisions for opportunity cost pricing for non-firm service must meet the requirements already discussed. If a utility chooses to adopt opportunity cost pricing, the non-firm rate is effectively capped by the availability of firm service and is not subject to a separately-stated price cap. If a utility chooses not to adopt opportunity cost pricing, the non-firm rate is capped at the firm rate. We also wish to ensure that non-firm transmission service is priced in a nondiscriminatory fashion. Accordingly, if a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own transactions, the same discounted rate must also be offered at the same time to non-affiliates on the same transmission path and on all unconstrained transmission paths. We will further require that any affiliate discounts from the maximum firm rate must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate.[454] In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory and must be reported on the OASIS within 24 hours of when available transmission capability (ATC) is adjusted in response to the transaction. As discussed in the RIN section, information, including the price for all non-firm transaction discounts, must be posted on the OASIS to ensure comparability.

2. Priority for Obtaining Service

Comments

The term ''priority'' is used in the comments in several senses. The intent of the comment depends on which kind of ''priority'' is intended. In general, there are comments about the order in which parties can obtain new service, which we call ''reservation priority,'' and there are comments about the order in which parties lose service they already have, which we call ''curtailment priority.'' Commenters may establish different reservation priorities for various services, such as network, off-system sales, firm, ability to reserve a portion of new transmission

[451] 74 FERC ¶ 61,006 at 61,010 (1996), *reh'g pending.*

[452] We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

[453] *E.g.*, Duke, SCE&G, AEP, FPL.

[454] The same requirements will apply to discounts from firm transmission service. Similarly, if a transmission provider offers an affiliate a discount for ancillary services, or attributes a discounted ancillary service rate to its own transactions, it must offer at the same time the same discounted rate to all eligible customers. Discounted ancillary services rates must be posted on the OASIS pursuant to new Part 37 of the Commission's regulations.

capacity to be constructed, and so on. Curtailment priorities also differ with the type of service. However, many commenters assert that certain parties should or should not have ''priority'' without distinguishing the kind of priority or type of service for which priority is intended.

a. Reservation Priority for Existing Firm Service Customers

Comments

Many IOUs, state commissions, and cooperatives strongly believe that native load should have priority to reserve transmission capacity under the tariffs.

EEI suggests that existing and future allocations of transmission capacity must be based on proper transmission pricing or, in its absence, priority of service. According to EEI, retail and existing wholesale requirements service should have the highest priority for use of transmission capacity, followed by long-term point-to-point service. Dayton P&L supports a continued preference for native load growth because native load customers have borne the majority of the costs of the transmission system. Detroit Edison, EEI, and Florida Power Corp claim that, because native load and network customers pay higher rates during all hours, such customers should have higher priority for service requests than others requesting transmission service. These commenters also claim that the transmission provider should be able to reserve firm capacity for native load and network service customers.

Similarly, NARUC wants wholesale and retail native load customers to be held harmless from functional unbundling of wholesale transmission services. Because these customers have borne the vast majority of the costs of the utility's transmission facilities, NARUC argues that priority of service, quality of service, and allocation of joint and common costs to native load customers should not be affected by the transition to an open access transmission regime.

PA Com does not share the Commission's concern that a transmission provider may discriminate against a third party transmission customer vis-a-vis native load. It finds nothing impermissible in this sort of discrimination, arguing that the interconnected system was financed by, designed for, and built to serve native load.

NRECA explains that most transmission customers that seek network service will already be receiving similar service (albeit in a bundled form) from their transmission providers. It argues that these customers should receive the same priority of service as the transmission provider's native load customers for as long as they continue to take network service, whether under a current bundled wholesale supply contract, a private transmission contract, or a network tariff.[455]

East Kentucky requests that the final rule clarify that member distribution cooperatives of G&Ts will have priority over third parties in the use of the G&T's existing transmission facilities. TVA comments that native load customers and emergency service to neighboring systems should have a higher service priority than transmission services sold to third parties (where an alternative power supply is available to the third party).

Commission Conclusion

We reiterate that we are not requiring the transmission provider to unbundle transmission service to its retail native load nor are we requiring that bundled retail service be taken under the terms of the Final Rule pro forma tariff. However, the amount of transmission capacity available to wholesale and unbundled retail customers under the Final Rule pro forma tariff is clearly affected by the amount of transmission capacity that the transmission provider reserves for the use of its native load customers and the future load growth of those customers. The transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon. However, the transmission provider is obligated to provide transmission service to others under the Final Rule pro forma tariff out of capacity reserved for native load growth up to the time the capacity is actually needed for such future needs. Furthermore, as we explained previously, while existing wholesale customers do not have any ownership-like rights to the capacity they used during the term of their contract, they will have a right of first refusal to that capacity after the expiration of their contracts or when their contracts become subject to renewal or rollover.[456]

b. Reservation Priority for Firm Point-to-Point and Network Service

Comments

A number of commenters argue that all firm service should *not* be treated equally. These commenters argue that the price of the service should determine the priority that the service receives. A large number of IOUs and potential network customers (existing requirements customers) argue that in light of the pricing implicit in the NOPR, (*i.e.,* 12 CP for network versus annual system peak for point-to-point) network service should have priority over point-to-point service (because, all other things being equal, the price for network service will be higher).

BG&E believes that a customer receiving service priority equal to native load and network customers should pay comparable rates. Thus, BG&E argues that either flexible firm point-to point service should be priced the same as network service, or point-to-point service should have a lesser priority than native load and network service customers if point-to-point service is priced lower than network service.

DE Muni believes that native load and network customers must have priority access to interfaces (particularly where they are constrained) after system reliability concerns have been satisfied. The same argument is advanced by commenters concerning long-term service versus short-term service. Public Generating Pool argues that long-term service should always have priority over short-term service because long-term customers contribute more towards fixed-cost recovery than do short-term customers.

Cajun objects to having its service and service to its customers, which it characterizes as network service, receive the same priority as firm point-to-point service customers who take service for periods as short as one hour. Cajun points out that it, as well as other network and native load customers, have been paying and will be paying for the transmission facilities in place to serve their needs for many years. According to Cajun, the transient firm point-to-point customer should not have equal standing. Cajun suggests, however, that a long-term firm point-to-point customer taking service for ten years or more should have service priority equal to native load and network service customers.

SC Public Service Authority argues that the availability of short-term firm service with a priority equal to long-term service would provide a means for short-term customers to obtain the advantages of long-term firm service at a much lower total cost. As a result, it argues that a few point-to-point customers would opt for long-term firm service, and the burden of the residual costs of the transmission system would fall on network customers.

EEI claims that priority for point-to-point service should be on a continuum of firmness, with reservation (as well as

[455] *See also* American Forest & Paper, AMP-Ohio.

[456] *See* discussion in Section IV.A.5.

curtailment) priority based upon duration of service and specific negotiated terms. EEI proposes that the point-to-point tariff be modified to provide a first-tier category of flexible point-to-point transmission service that is comparable in priority, price, length, and terms of service to network service. EEI believes that this modification will resolve the problems that are associated with establishing priorities between network service and point-to-point service if the Commission retains different CP cost allocation methods for each service.

On the other hand, CCEM, a group of power marketers, supports the concept that all firm service should be treated equally, regardless of the term or the nature of service.

Commission Conclusion

An essential element of non-discriminatory transmission access is the right of transmission customers to reserve and purchase transmission service that is of the same quality as that used by the transmission provider in serving its wholesale requirements customers and retail load. Thus, we reject the proposal of some commenters that transmission providers need not provide firm point-to-point service that is of the same ''firmness'' as the transmission provider's service to native load. However, the fact that both network service and point-to-point service are provided on an equally firm basis does not mean that both types of service must be priced or reserved in the same manner.

The comments about reservation priorities for firm services boil down to two concerns. First, due to the differences in pricing firm point-to-point service and network service implicit in the NOPR (*i.e.*, twelve-monthly CP pricing for network versus annual system peak for point-to-point), some commenters believe that network service should have priority over point-to-point service. Second, some commenters maintain that according firm, short-term point-to-point service a priority equal to long-term service provides a means for short-term customers to avoid making a fair contribution to the long-term costs of the system.

With respect to the first concern, we have eliminated the differences in pricing by permitting utilities to adopt point-to-point reservations as the customer load. As discussed above, for purposes of the Final Rule pro forma tariff, utilities are free to propose a single cost allocation method for the two services.

The second area of concern arises because of the first-come first-served reservation priority in the NOPR point-to-point tariff. The Commission recognizes that the tariffs, as proposed in the NOPR, provide the opportunity for a customer to reserve certain valuable rights (*e.g.*, the right to short-term firm service during peak periods) while avoiding in part the long-term costs of the system (perhaps by relying on non-firm service during lengthy off-peak periods when there is a substantially reduced chance of interruption). However, the Commission has a countervailing concern that the transmission provider should not be able to withhold valuable transmission capacity from potential customers if that capacity is not being used by those who are paying for the long-term costs of the system.

Accordingly, the Final Rule pro forma tariff provides a mechanism to address this concern while safeguarding the rights of potential customers to obtain access to unused capacity. The tariff provides that reservations for short-term firm point-to-point service (less than one year) will be conditional until one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. These conditional reservations may be displaced by competing requests for longer-term firm point-to-point service. For example, a reservation for daily firm point-to-point service could be displaced by a request for weekly firm point-to-point service during an overlapping period. Before the applicable reservation deadline, a holder of a conditional firm point-to-point reservation would have the right of first refusal to match any longer-term firm point-to-point reservation before being displaced. After the deadline, the reservation becomes unconditional, and the service would be entitled to the same priorities as any long-term point-to-point or network firm service.[457]

The Final Rule pro forma tariff does not propose point-to-point or network service with various degrees of firmness beyond the simple categories of firm and non-firm. When a customer requests firm transmission service, reservation priorities are established based first on availability, and in the event the system is constrained, based on duration of the underlying firm service request; customers may choose the ''firmness'' of service they want by electing to take non-firm service, or by reserving and paying for firm service. We have not included any degrees of firmness in the Final Rule pro forma tariff because having intermediate categories of firmness under point-to-point or network service would, we believe, unnecessarily complicate the priority system. However, utilities are free to propose and fully support different reservation priority provisions for firm service in subsequent rate filings as long as those provisions are not unduly discriminatory, fully comply with the principles of comparability, and are priced appropriately.

c. Reservation Priorities for Non-Firm Service

Comments

IOUs, state commissions, and potential network customers tend to support the service reservation priorities for non-firm service set forth in the NOPR pro forma tariffs (*i.e.*, transmission service by network customers for economy purchases to serve network load has a higher priority than non-firm point-to-point service, which has a higher priority than a firm point-to-point customer using transmission service at secondary points of receipt and delivery). However, because network customers pay a higher rate than point-to-point customers, these commenters argue that network customers should be permitted to use their off-peak load ratio share of the transmission system to make off-system sales. Many commenters argue that point-to-point customers can use their secondary service for both purchases and sales; thus, they believe it is discriminatory to limit network customers to purchases at secondary points.

Commenters that are opposed to the service reservation priority scheme in the NOPR pro forma tariffs argue that transmission providers will discriminate against third party users in favor of their native load economy purchases. These commenters argue that all non-firm service should have equal priority.

Other commenters, such as CINergy, would base priority on the duration of service. CINergy claims that this method would eliminate what it claims is an advantage (over network) given in the NOPR to point-to-point service in making short-term purchases. TVA notes that it establishes priority for non-firm service based on duration of service requested, with customers in each service category receiving priorities based on the rate they wish to pay.

Some commenters believe that the transmission price should affect the

[457] The service itself, as opposed to reservations, is subject to the curtailment provisions discussed below.

priority of customers to obtain non-firm transmission capacity.[458] However, other commenters argue that this seems to be precluded by the NOPR pro forma tariffs' service priority provisions.

Although PSE&G believes that the NOPR pro forma tariffs suggest a first-come, first-served allocation method for capacity in excess of that needed for firm transmission service, it proposes a fixed period of time for all potential users to submit bids for service (*e.g.*, one week prior for monthly service), allowing the bid price to determine priority (*i.e.*, the higher bid prices receive service priority over lower bid prices). According to PSE&G, customers could bid an ''up to'' rate subject to a price floor, with all revenues flowed back to firm service customers. TVA also advocates departing from the first-come, first-served approach for allocating some uses of the transmission system, claiming that price is an effective means to establish priority for non-firm and short-term firm services.

Utility Wind Interest Group requests that non-firm service used for transmitting renewable resources be given a higher priority than non-firm service used for transmitting conventional resources because renewable resources cannot store their fuel supply.

Commission Conclusion

We continue to believe that network economy purchases should have a reservation priority over non-firm point-to-point and secondary point-to-point uses of the transmission system. Network transmission customers are obliged to pay all of the costs of the transmission system without regard to the resources from which energy is scheduled. Therefore, it is appropriate that the transmission associated with a network customer's economy purchases (*i.e.*, transmission that is used to substitute one resource for another on an as-available basis) enjoys a higher priority than non-firm point-to-point transmission service.

Regarding the reservation priority for non-firm service under point-to-point service, we will adopt a reservation priority based upon duration of non-firm service, with price acting as a tie-breaker for competing service requests of an equal duration. If there is insufficient transmission capacity to accommodate all non-firm transmission requests, the reservation of longer duration should displace the shorter. For example, a reservation for a month of non-firm service will displace a reservation for a week of non-firm service. Also, a reservation for a week will displace a reservation for a day, which will displace a reservation for an hour of non-firm service. If a customer requests non-firm and later another customer requests longer-term non-firm service before either term of service begins, the first customer to request service has the right of first refusal to change its request to the longer term of service. A firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest reservation priority.

3. Curtailment Provisions

a. Pro-Rata Curtailment Provisions

Comments

A large number of IOUs that are control area operators argue for discretion to curtail the transaction that most effectively relieves the constraint, in lieu of mandatory pro-rata curtailments, which they argue are inappropriate and not cost effective.

Other commenters that do not support pro-rata curtailment argue that preference should be given to native load or existing customers because these customers have paid the majority of the costs of the transmission system. A large number of customers note that their existing contracts contain ''enhanced'' curtailment priorities (*i.e.*, service to others will be curtailed before service to customers with such curtailment priority) due to the large capital outlays made by them in connection with their service.[459]

Public Generating Pool believes that the proposed curtailment provisions may not be flexible enough for transactions in the Northwest. It argues that hydro spill should be avoided, and suggests that transactions from federal and/or non-federal hydroelectric generation facilities should not be curtailed pro rata with other transactions that do not rely on such facilities. Public Generating Pool urges that regional agreements (*e.g.*, regional transmission group agreements) that would achieve this goal should be given deference.

Other commenters support pro-rata curtailments for firm service.[460] PSNM states that this has been its operating practice in the past, and PSNM expects to continue such an approach in the future.

Power marketer commenters generally support the pro-rata curtailment adding that a standardized curtailment priority applied nationally would provide greater open access and eliminate discriminatory curtailments.

Commenting on a related subject, EEI maintains that the network tariff provision for termination of service in the event a customer fails to curtail load [461] may not be realistic for service to a Transmission Dependent Utility. EEI suggests that the Commission supplement this provision with a substantial penalty provision, coupled with an indemnification requirement.

Commission Conclusion

It was not our intent in the NOPR to require all transactions to be curtailed on a pro-rata basis regardless of whether the transaction relieves a constraint. We intended to permit curtailments of transactions that substantially relieve a constraint.[462] We intended and continue to believe that curtailment on a pro-rata basis is appropriate for curtailing the transactions that substantially relieve the constraint. In order to allay the concerns of the commenters addressing this issue, we are clarifying the curtailment provision of the tariff to explicitly allow the transmission provider discretion to curtail the services, whether firm or non-firm, that substantially relieve the constraint. Of course, any curtailment must be made on a non-discriminatory basis, including curtailment of the transmission provider's own use of the transmission system. Customers that believe the curtailment policy is administered unfairly may file a section 206 complaint at the Commission.

Concerning the request of certain Pacific Northwest commenters, we would consider granting deference to an alternative curtailment method to avoid hydro spill if such a regional practice is generally accepted and adhered to across the region, as discussed further in Section IV.K.

Finally, we agree with EEI's observation that terminating network

[458] *E.g.*, Duke, Orange & Rockland.

[459] *E.g.*, TANC, Turlock, SMUD.

[460] *E.g.*, PSNM and Nebraska Public Power District.

[461] Proposed Pro Forma Network tariff section 9.7—System Reliability.

[462] The Final Rule pro forma tariff contains language allowing the transmission provider the discretion to interrupt firm transmission service in an emergency or other unforeseen condition in a manner suggested by these commenters. Section 11.6, Curtailment of Firm Service, of the Final Rule pro forma tariff provides:

However, the Transmission Provider reserves the right to interrupt, in whole or in part, firm Transmission Service provided under this Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its transmission system.

The reference to curtailments being allocated on a proportional (pro rata) basis addresses situations where multiple transactions could be curtailed to relieve a constraint.

service under the tariff to a transmission dependent utility that fails to curtail load as required may not be appropriate. As a result, we clarify that under network and point-to-point service, the transmission provider may propose a rate treatment (penalty provision) to apply in the event a customer fails to curtail load as required under the Final Rule pro forma tariff. Such proposals will be evaluated on a case-by-case basis on compliance.

b. Curtailment Provisions for Non-Firm Service

Comments

A number of commenters seek clarification of the curtailment provision for non-firm service under the two tariffs. They note that economy purchases by the network customer are accorded a higher curtailment priority than non-firm service under the point-to-point tariff. However, under the point-to-point tariff there is no acknowledgement of this higher priority for network service. Curtailments for non-firm transmission service under the point-to-point tariff are simply based upon duration of service, without reference to a higher priority for network economy purchases.

A number of commenters, including Industrial Energy Applications, suggest that a price-based curtailment queue for non-firm transmission will facilitate economy energy deals in highly competitive wholesale power supply markets and allow the parties to directly address delivery risk through the pricing mechanism.

Blue Ridge argues that the final rule should provide equal curtailment priority for all types of non-firm transmission service. Utilities For Improved Transition argues that network customers should be able to transmit non-firm power imports under the network tariff with the same curtailment priority that is assigned to all other firm network uses of the transmission system.

A number of commenters note that the tariffs allow non-firm service to be interrupted only for emergency or reliability reasons or to provide firm service. These commenters contend that, under this requirement, curtailment of non-firm service is unlikely.[463] As a result, they believe that non-firm service is elevated to firm service. To remedy this situation, these commenters argue that transmission providers should have the ability to curtail non-firm service for any economic reason.

Commission Conclusion

We have clarified in the Final Rule pro forma tariff that a network customer's economy purchases have a higher curtailment priority than non-firm point-to-point transmission service.

A higher curtailment priority should be provided to network economy energy purchases for the reasons stated in *AES Power, Inc.*.[464] In that case, we recognized that the network transmission customer has already ''paid'' for the transmission of its economy purchases (*i.e.,* transmission that is used to substitute one resource for another on an as available basis) through its payment of a load ratio share of the system.

Many commenters oppose the point-to-point service provision allowing non-firm service to be interrupted only for emergency or reliability reasons or to provide firm service. Upon further consideration, we agree that this provision is too narrow. Accordingly, the Final Rule pro forma tariff is revised to allow the transmission provider to curtail non-firm service for reliability reasons or economic reasons (*i.e.,* in order to accommodate (1) a request for firm transmission service, (2) a request for non-firm service of greater duration, (3) a request for non-firm transmission service of equal duration with a higher price, or (4) transmission service for economy purchases by network customers from non-designated resources.). However, all curtailments must continue to be made on a non-discriminatory basis including curtailments of the transmission provider's own non-firm uses of the transmission system under the tariff. A firm point-to-point customer's use of transmission service at secondary points of receipt and delivery will continue to have the lowest curtailment priority.

4. Specific Tariff Provisions

a. Network and Point-to-Point Customers' Uses of the System

Comments

Generally, transmission providers argue that the tariffs give too much flexibility to customers, while transmission customers argue that even more flexibility is required. The arguments are generally tied to pricing rather than technical problems with providing any level of service.

A common transmission provider argument is that the proposed firm point-to-point tariff provides a premium service comparable to network service, but at a lower rate. It has been suggested that either the flexibility to use non-firm service at secondary points of receipt and/or delivery at no additional charge under the point-to-point tariff be eliminated or that point-to-point customers should pay a premium price for such flexibility.[465] Transmission providers generally argue that flexible point-to-point service puts the transmission owner and the network customer at a competitive disadvantage. They assert that the point-to-point customer is able to use non-firm transmission to reach secondary receipt and delivery points for both sales and purchases, but the network customer may use only non-firm transmission to reach secondary points for purchases. Thus, they argue, the flexible point-to-point users can sell non-firm power with a small or even no transmission component (because the underlying transmission is effectively free). Electric Consumers Alliance and Cajun believe that the owner and network customer competing for that sale should not be charged for the identical transaction. Absent a change to the point-to-point tariff, a number of transmission providers and state commissions (including Midwest Commissions) argue that to provide balance to the tariffs, the network tariff should permit the network customers to have non-firm transmission to secondary receipt and delivery points at no additional charge for both purchases and sales within its load-ratio transmission entitlement. Utilities For Improved Transition refers to this proposed network tariff modification as ''headroom.''

CCEM opposes the headroom concept, arguing that ''free'' use of capacity will give transmission providers an unfair competitive advantage. CCEM also cites Order No. 636 in support of its position.

Conversely, a number of customer groups believe the point-to-point tariff should be made more flexible by broadly defining the concept of points of receipt and delivery. They argue that all points of connection between the transmitting utility and the purchasing utility should be treated as a single point of delivery (POD) or point of receipt (POR).[466] In this manner, a customer would not have to pay for every point of receipt or point of delivery, but could select a contract demand level of service. The customer could then use the service at multiple

[463] *E.g.,* Florida Power & Light Company, Southern California Edison Company.

[464] 69 FERC ¶ 61,145 at 62,300 (1994) (proposed order), 74 FERC ¶ 61,220 (1996) (final order).

[465] *E.g.,* EEI, Utility Working Group, SoCal Edison.

[466] *E.g.,* Arkansas Cities, NRECA.

points without incurring separate reservation charges for each point.

A number of commenters contend that the Commission should not force specific tariffs on public utilities in the Pacific Northwest due to their unique status.[467] In particular, NWRTA recommends that the final rule recognize that the Pacific Northwest's integrated transmission system, including large components owned by non-public utilities, was constructed to support a unique region-wide hydroelectric-dependent generating system. NWRTA recommends that the final rule be sufficiently flexible to accommodate these unique characteristics without prejudicing the interests of users or providers of transmission services.

Similarly, Public Generating Pool states that the NOPR pro forma network tariff departs from the status quo arrangements in the Northwest and is generally unworkable because generation is usually remote from the control area serving the network load and because BPA, which does not have a typical service territory, dominates the regional transmission market. Public Generating Pool suggests that the Commission require, and the region develop, a ''generation integration'' transmission tariff that would offer network-type service to a source or sources of generation unbundled from the ''network services'' designed to integrate load. Similar contract demand network tariffs have already been proposed by some IOUs.

Commission Conclusion

We will not allow network customers to make off-system sales within the load-ratio transmission entitlement at no additional charge. Commenters have raised no new arguments to persuade us to do so. The primary purpose of network service is to integrate resources to serve loads. Use of transmission by network customers for non-firm economy purchases, which are used to displace firm network resources, must be accorded a higher priority than non-firm point-to-point service and secondary point-to-point service under the tariff. Off-system sales transactions, which are sales other than those to serve a network customer's native load, must be made using point-to-point service. They can be made on either a firm or non-firm basis.

A large number of transmission providers support the ''headroom'' concept, arguing that without it the flexible point-to-point service puts them at a competitive disadvantage. This would be true if a utility serving load were required to use network service exclusively. However, we do not require any utility to take network service to integrate resources and loads. If any transmission user (including the public utility) prefers to take flexible point-to-point service,[468] they are free to do so. Any point-to-point customer may take advantage of the secondary, non-firm flexibility provided under point-to-point service equally, on an as-available basis.

b. Minimum and Maximum Service Periods

Comments

Commenters raise issues regarding the minimum term of one hour for firm point-to-point service. Their concerns center on price and priority. Transmission providers point out that their native load customers pay the fixed cost of the transmission system every hour of the year. They argue that comparability is not achieved by permitting others to have service for one hour with equal priority to native load and other long-term customers. Others worry that the one-hour minimum term will: (1) Promote the selective use of the transmission system; (2) impair the ability of a utility to plan its system; and (3) adversely impact longer term transactions.

Tallahassee and KY Com are concerned that one-hour firm service may encourage speculative advance requests for service during the system peak day (Cajun refers to this as cream skimming). These commenters express concern that such requests could displace other valid transactions or constrain a corridor or interface to the detriment of network service or native load customers. Tallahassee proposes a one-day minimum term for firm service.[469]

East Kentucky is concerned that users of the transmission system could, under the Commission's proposed open-access rule, purchase short-term firm service during peak months in lieu of annual firm service to reduce expenses associated with the purchase of firm transmission service. By buying short-term firm service only during the peak months, an entity can significantly reduce its transmission expenses by purchasing non-firm service during off-peak months when the available transmission capacity far exceeds the demand on the transmission system. For this reason, some commenters request that short-term firm service be priced to generate revenues over the peak months equal to the charge for annual firm service.

Duke argues that, because all curtailments are equal, the addition of each one hour firm transaction will lower the reliability profile of native load customers and other customers with long-term commitments. It suggests that different classes of services be established that offer transmission customers the flexibility to obtain an intermediate level of transmission service (between native load firm and non-firm) for transactions of shorter duration.

On the other hand, some TDUs and power marketers support the one-hour minimum term. TAPS argues that transmission providers should not be permitted to restrict the availability of hourly, daily or weekly transmission service at reasonable prices, as some transmission providers have proposed in open access cases. Brazos supports a minimum duration of service equal to the minimum scheduling period of the transmission owner. Turning to the maximum term of service, Chugach objects to the imprecise requirement that transmission service be offered for a term equal to the life of a particular generation resource. Chugach, joined by VEPCO, suggests that the Commission require transmitting utilities to offer five-year terms (with longer contract terms by negotiated agreement).

Although BPA supports eliminating arbitrary term limitations and facilitating long-term resource commitments, it is concerned that the Commission's failure to specify a maximum term for firm transmission service (particularly where no specific resource is being wheeled) requires transmitting utilities to effectively sell off their transmission capacity to third parties. In BPA's view, such a requirement goes well beyond the intent of the Energy Policy Act.

PSE&G argues that the term limit for firm transmission service should be consistent with the transmission provider's planning horizon (*e.g.*, for PSE&G, 10 years), which will ensure comparability of firm third party customers with native load. According to ConEd, failure to specify a maximum term for service creates uncertainty for planning purposes. PECO believes that utilities should have the right to limit the term of service to either: (1) The expected useful life of facilities used in providing service; or (2) the term of permits and land rights needed for those facilities.

[467] *E.g.*, Public Power Council, Washington Water Power, NWRTA.

[468] *See* Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 at 61,013 and n.70 (1996).

[469] *See also* VEPCO, CSW, NYSEG, WP&L.

Commission Conclusion

We will adopt a one-day minimum term for firm point-to-point service. The one-day minimum term for firm point-to-point service, along with modifications to the procedures for requesting firm point-to-point service, will moot a number of reliability concerns and allegations about possible ''cream-skimming.'' As discussed *supra*, firm service requests with longer durations of service will have bumping rights over shorter term firm service requests. Also, the one-day minimum will not disadvantage anyone because the transmission provider will be subject to the same one-day term for its firm point-to-point uses of the transmission system. Because of the longer-term nature of network service, it will be subject to a one-year minimum term.

We will not specify a maximum term for either point-to-point or network transmission service. However, we recognize the concerns raised by commenters that a commitment of uncertain duration makes planning difficult. Therefore, we will modify the tariff to require that an application for transmission service specify the length of service being requested. This will provide the transmission provider with the certainty it needs for planning and the transmission customer with the flexibility to request the service it needs.

c. Amount of Designated Network Resources

Comments

The NOPR pro forma network tariff specifies that a customer may designate only those resources that the customer owns or has committed to purchase pursuant to an executed contract. Transmission providers argue that there is a need for some limitation on the resources that network customers can designate to serve their loads. Otherwise, they assert, a utility would be required to incur costs (planning, constructing, and operating its transmission system) that are out of proportion to the customer's load and its share of the utility's cost of service. However, EEI, VEPCO, and Utilities For Improved Transition believe that the Commission's proposal to use a purchase obligation standard is too narrow, inflexible, and susceptible to manipulation. These IOU commenters argue that it could include very short-term obligations and contingent obligations to purchase. EEI suggests that the Commission should establish a minimum term so that a customer could not designate resources for which it has only a one-month contract. The principal problem VEPCO sees is that purchase obligations may not be clear. According to VEPCO, a transmission customer may claim an obligation when it has no substantial payment obligation and thus no economic deterrent to designating that purchase obligation as a potential resource to serve its loads. It alleges that the result is that the transmitting utility can be forced to tie up transmission capacity for service from a resource that may have little probability of being used; consequently, less capacity will be available for other uses. VEPCO further argues that, since upgrade costs are typically rolled in, the customer may not have a strong incentive to minimize transmission construction. EEI argues for system-specific limits based on capacity needs to serve the network loads reliably. Alternatively, if the ''own'' or ''purchase'' provision is to be used, EEI contends that the customer should be required to have a significant and ongoing obligation to purchase power (*e.g.*, minimum one-year contracts that impose obligations on a first-call basis).

These IOUs also recommend that the Commission not decide on a single way to limit network resources. They note that proposals based on percentage limits (*e.g.*, 125%) subject to exceptions for reliability concerns may be a reasonable approach. According to these IOUs, the Commission should permit flexibility to develop not unduly discriminatory provisions until experience suggests which are the best ways to satisfy the objective. To prevent over-designating network resources, Missouri-Kansas Industrials suggest placing a limit of 200% of the subscriber's load.

Arkansas Cities supports limiting the definition of network resources to those that the customer owns or contracts for. It argues that this reasonably accommodates the planning process. Arkansas Cities argues that any type of percentage adder would unreasonably restrict the process.

ELCON states that virtually any issue regarding the nature of network service can be resolved by reference to the price of such service. According to ELCON, if a transmission customer seeks to incorporate unlimited (*i.e.*, unspecified) generation sources into its network load, the customer should pay a higher rate than a network customer that can identify a need for service to/from specified generating units.

A related issue is how interface capacity should be allocated between network customers and the transmission provider. IOUs generally argue that interface capacity should be allocated based upon the load ratio of the customers. Tariff customers generally argue that there should be no restriction on the amount of interface capacity that they may designate.

Commission Conclusion

We do not believe that a superior alternative has been suggested to our purchase obligation for limiting network resources. Accordingly, we will not change the limitation on the amount of resources a network customer may designate. A transmission provider taking network service to serve network load under the tariff also is required to designate its resources and is subject to the same limitations required of any other network customer.

Limiting the amount of resources to those that the customer owns or commits to purchase will protect a utility from having to incur costs that are out of proportion to the customer's load. The transmission provider's concern that the purchase limitation will result in excessive network resources is unfounded. A transmission customer, like a transmission provider, has an incentive not to oversubscribe its capacity requirements because the cost of excessive reserve margins will be prohibitive. Requiring a strict percentage limitation could distort the planning process by limiting the size of resource additions a transmission customer may undertake. Allowing discretionary exceptions to the percentage limit will inevitably lead to disputes and claims of discrimination.

With respect to the allocation of interface capacity under network service, we clarify that a customer is not limited to a load ratio percentage of available transmission capacity at every interface. A customer may designate a single interface or any combination of interface capacity to serve its entire load, provided that the designation does not exceed its total load.

d. Eligibility Requirements

Under the NOPR pro forma tariffs, the transmission provider and anyone who can file a section 211 request is eligible to request service.

Comments

In general, most commenters agree with the eligibility requirements. However, several IOUs argue that the tariffs should be modified specifically to preclude the use of the tariffs for retail wheeling.[470]

NIEP believes the eligibility provision should include all entities that not only generate power themselves, but also purchase power generated by others for

[470] *E.g.*, El Paso, Southern, NSP.

resale, including municipalities, federal entities with rights to purchase, and other entities with load but no generation resources.

Power Marketing Association and others argue that the network tariff should be modified to specifically allow service to marketers.

PacifiCorp argues that independent owners of generation resources should not be allowed to acquire network integration service directly. It suggests that, if the eligible utility does not have a load in the control area, the service sought is to accommodate off-system sales, which is a point-to-point service.

Commission Conclusion

As we previously explained, a non-discriminatory open access transmission tariff must be made available, at a minimum, to any entity that can request transmission services under section 211 and to foreign entities.[471] Eligibility to take service is further discussed in Section IV.C.1.

e. Two-Year Notice of Termination Provision

Comments

Ohio Edison, Utilities For Improved Transition, LA DWP, and VEPCO believe that point-to-point transmission customers should not be allowed to terminate transmission service prior to the end of their contract term, especially in light of their reassignment rights. For network service, VEPCO, Florida Power Corp, Utilities For Improved Transition, and Duke believe that the notice of termination period should be at least five years, to coincide with the utility's construction horizon. In particular, VEPCO wants transmission customers terminating service prior to the end of the contract term to pay for network upgrades constructed for their benefit that would be stranded due to early termination of service.

CCEM supports a six-month notice of termination as appropriate for a term of service of one year or greater; any longer notice period would unduly limit a transmission customer's purchasing options.

NYSEG and EEI want the flexibility to negotiate a reasonable, mutually agreeable notice of termination period to recognize such things as the term of the contract and the amount of service at issue.

LEPA, VT DPS, and NorAm believe that written notice of termination should not be required for transactions of two years or less.

[471] *See* discussion in Section IV.C.1.

Commission Conclusion

We will delete the notice of termination provision from the tariff. We believe that commenters have raised a number of valid concerns about including the notice of termination provision. In particular, the notice of termination will have no effect on short-term service of less than two years. In addition, the two-year notice provision does not coincide with either a transmission provider's planning or construction horizon. Because we are eliminating the notice of termination provision from the tariff, transmission service will have to be reserved and paid for over the length of the contract term. Of course, by eliminating this tariff provision, we are not precluding parties from negotiating mutually agreeable terms for early termination on a case-specific basis. However, we note that point-to-point customers are able, under the reassignment provision, to resell unused transmission capacity.

f. Reciprocity Provision

In the NOPR, the Commission explained that it was requiring a reciprocity provision in the non-discriminatory open access transmission tariffs so that public utilities offering transmission access to others would be able to receive service from transmitting utilities that are not public utilities (*e.g.*, municipal power authorities and federal power marketing administrations that receive service under a public utility's tariff).

Comments

Reciprocity Requirement

The vast majority of the jurisdictional IOUs commenting on this issue favor a reciprocity requirement. In contrast, the non-jurisdictional transmission customers (primarily publicly-owned entities and cooperatives) generally oppose such a requirement. The few state commissions commenting on this issue generally support the stated goal of the reciprocity requirement, but question our legal authority to require it.[472] The few IPP and power marketer commenters that address this issue do not object to reciprocity if it does not apply to non-transmission owners.[473]

Several commenters believe that all transmission-owning utilities, whether public or investor-owned, must be required to provide open access service for a truly competitive wholesale power market to be realized.[474] Sierra states that specific legislation by Congress

[472] *E.g.*, IL Com, KY Com, VT DPS, GA Com.

[473] *E.g.*, CCEM, CA Energy Co.

[474] *E.g.*, Sierra, MidAmerican, Tucson Power.

and/or state lawmakers may be necessary to ensure that currently non-public utilities comply with the Commission's open access requirements.

A number of commenters maintain that the Commission should enforce reciprocity by allowing public utilities to deny transmission service to non-public utility transmitting entities when reciprocal transmission service is not offered.[475]

Phelps Dodge and Otter Tail believe that non-public utility transmitting entities will continue their existing bundled service contracts indefinitely to avoid complying with the reciprocity requirement. Therefore, to promote transmission access through reciprocity, Phelps Dodge and Otter Tail suggest requiring the unbundling of existing contracts by a date certain to convert such contracts to transmission service agreements under the transmission provider's open access tariff.

A number of commenters argue that the Commission's only legal authority to impose a reciprocity requirement on non-public utilities is that provided by section 211 of the FPA.[476] Large Public Power and others suggest that mandating reciprocity is not necessary because the stated goals of the reciprocity requirement can be met by voluntary transmission access and through section 211 filings.

Many commenters do not oppose reciprocity if it is modified to incorporate the protections present in sections 211 and 212 and the benefits available under sections 205 and 206.[477] TDU Systems explains that section 211 contains a number of protections, *e.g.*, transmitting utilities cannot be required to provide transmission service if such service impairs their ability to provide reliable service, disrupts existing contracts with entities seeking service, or is inconsistent with state law regarding retail marketing areas. It also notes that section 212 contains rate provisions that protect a non-public utility transmission provider from being forced to provide electric service at a non-compensatory rate. Seminole EC argues that, without section 205/206 rights, non-public utilities cannot adjust their tariffs or challenge tariff provisions that they believe should not apply to them.

Several commenters also suggest that, without sections 211, 212, and 205 rights and protections, reciprocity

[475] *E.g.*, Puget, Sierra, NSP.

[476] *E.g.*, NRECA, Omaha Public Power District, Dairyland, AEC & SMEPA, PA Com, IL Com, TDU Systems.

[477] *E.g.*, NRECA, SC Public Service Authority, Seminole EC, TDU Systems.

provisions allow the transmission provider to deny transmission based on its own determination of the transmission customer's attempt to comply with reciprocity, which SC Public Service Authority contends is letting the ''fox guard the henhouse.'' TAPS states that in no event should the claimed lack of reciprocity constitute grounds for refusal to offer a service agreement, or unilateral denial, delay or termination of service. TAPS, and other cooperative, municipal, and public power commenters suggest that some procedure must be developed to bring reciprocity disputes before the Commission. Wisconsin Municipals argues that this provision should be modified, claiming that a customer's receipt of a revenue credit for transmission facilities it contributes to the transmission provider's system should satisfy the reciprocity requirement.

Rather than filing tariffs with the Commission, Dairyland suggests allowing cooperatives that are not public utilities to file a compliance transmission tariff with the Rural Utilities Service (RUS) as it relates to the issue of reciprocity, thereby affording non-jurisdictional cooperative utilities rights and privileges similar to those afforded jurisdictional utilities.

Application of Reciprocity Requirement

Several commenters argue that reciprocity should apply to both the seller and purchaser engaged in a transaction under an open access tariff to ensure that: (1) Transmission customers cannot avoid their reciprocity obligation by requesting service through an agent that owns no transmission facilities; (2) a generator cannot take transmission service in order to sell power to a non-jurisdictional entity, thereby allowing the non-jurisdictional entity to escape the reciprocity provision, and (3) a buyer cannot take service in order to purchase power from a non-jurisdictional entity, thereby allowing the entity to escape the reciprocity requirement.[478]

Entergy also is concerned that reciprocity can be evaded through the use of power marketers. Therefore, Entergy proposes that, if the transmission customer is neither the producer, transmitter, nor distributor of the power and energy to be transmitted, but instead acts as a marketer, the marketer must designate an electric utility that either produces, transmits, or distributes such power and energy as being subject to the requirement to provide comparable service.

CCEM and NIEP support the reciprocity provision because they apply only to transmission owners. CCEM and NIEP contend that non-transmission-owning customers should not be required to procure transmission capacity or hire a proxy solely to meet a reciprocity requirement.

In contrast, CA Energy Co insists that the reciprocity provisions of the proposed tariffs must be amended to clarify that IPPs can obtain access even if the IPPs own no transmission assets. CA Energy Co argues that the Commission must exempt IPPs from the reciprocity requirement if IPPs are to be assured equal access and thus remain effective competitors.

Publicly-Owned Entities

Publicly-owned entities argue that they differ from IOUs and cannot provide completely reciprocal services.[479] LPPC identifies a number of differences between publicly-owned utilities and IOUs, such as: the publicly-owned utilities' use of tax-exempt debt, which could be jeopardized if they are required to make their transmission systems available for private use; restrictions on the rate-setting methods publicly-owned utilities can use; and statutory restrictions on the services publicly-owned utilities can offer.[480] LPPC asks that the reciprocity provision be dropped or changed to recognize these differences.[481] It argues that the purposes of the NOPR are met by transmission tariffs voluntarily offered by its members that generally meet the standard of open access.

NE Public Power District notes that to the extent that the Commission requires cost-based rates, the Commission must recognize that publicly-owned utilities do not establish rates in the same manner as IOUs; for example, NE Public Power District does not include depreciation or return on equity as costs in its rates, nor does it pay federal income taxes. It suggests that the Commission should not apply a one-size-fits-all approach to pricing transmission service, should consider the special circumstances of publicly-owned utilities in exercising its authority under section 212, and should give publicly-owned utilities the opportunity for an evidentiary hearing before requiring them to adopt rate-setting conventions that are appropriate for public utilities.[482]

CAMU asserts that the tax-exempt financing of government bodies may be jeopardized due to limitations on the private use of facilities that are financed through tax exempt bonds.[483] It suggests that a solution may be to impute the cost of capital based on the average cost of all area utilities. Wisconsin Municipals says that the Commission should seek an opinion from the IRS regarding whether reciprocal use would jeopardize tax-exempt status; if it is determined it would, the owner of the transmission facilities should be allowed to recover any increased costs associated with the loss of tax-exempt status.[484]

DE Muni is concerned that a utility may ''impose'' the open access tariffs on a non-public utility customer such as a municipal system and then demand reciprocal access to that customer's transmission facilities to serve the municipal's retail customers.

San Francisco argues that there is no legal authority in the FPA or case law to impose the open access requirement on non-public utility entities. Moreover, San Francisco is concerned that the reciprocity requirement may impair its ability to deliver its own power pursuant to the requirements of the Raker Act.

Salt River opposes the reciprocity provision because it could ''administratively vest discriminatory market power in FERC jurisdictional public utilities.'' Salt River further argues that ''duly adopted open access transmission tariffs or rate schedules of publicly-owned utilities should be presumed to satisfy FERC's reciprocity requirement, and the legislative action of the publicly-owned utility's ratemaking body should be given deference in a dispute brought before FERC relating to the tariff or rate schedule.''

Public Generating Pool argues that a non-public utility transmission customer should not have to provide the same service a public utility provides. It argues that a publicly-owned entity may lack the resources to provide the high level of service a public utility can provide.

Tallahassee seeks clarification that reciprocity does not mean that investor-owned utilities can require municipal utilities to offer services that are *identical* to those offered by the

[478] *E.g.*, EEI, Consumers Power, Montana-Dakota Utilities, CSW, Duke, BPA.

[479] *E.g.*, Blue Ridge, SMUD, LPPC, Salt River, Oglethorpe.

[480] *See also* Omaha PPD, Salt River, MEAG, TAPS.

[481] *See also* Omaha PPD.

[482] *See also* Heartland.

[483] *See also* Wisconsin Municipals, Omaha PPD, Salt River, MEAG, MMEWC, NE Public Power District.

[484] *See also* TAPS.

investor-owned utilities. It argues that it is not practical to require small utilities to provide all of the services bigger utilities provide and that legal obligations imposed on municipal utilities may interfere with their ability to provide certain types of open access provisions. Tallahassee concludes that reciprocity should be equated with comparability (the transmission user must offer service that is comparable to the service it offers to itself).

TANC asks for clarification and suggests various changes to the reciprocity provision. It asks whether the reciprocity requirement will apply to it, since it is part owner of a transmission facility (the California Oregon Transmission Project (COTP)) but has contractually dedicated its entitlement to use of this facility to its members. It argues that if the requirement does apply, its obligation should be limited to the member's share of TANC's entitlement. TANC also asks whether when it receives transmission service on behalf of a member, that member's non-COTP transmission facilities must be made available to the transmission provider. If that is the case, TANC asks what voltage level of facilities must TANC and its members make available? TANC believes that if a TANC member independently requests transmission service from a utility, that member would be obligated to make reciprocal service available to the utility on the share of the COTP that member ''controls'' through TANC's entitlement. TANC argues that neither TANC and its members nor TANC and its COTP co-owners should be treated as ''affiliates'' under the proposed reciprocity provision. It argues that the comparable service tariff it must provide as a member of the Western Regional Transmission Association should satisfy the reciprocity requirement.

TANC also asks for clarification as to how the reciprocity provision would be administered. A non-public utility cannot file a tariff with the Commission, so presumably it and the public utility from which it wants transmission service would negotiate; if, however, the public utility does not agree that reciprocal service is being offered, it will deny access to its transmission facilities, and the non-public utility would have to come to the Commission to resolve the dispute. SC Public Service Authority expresses a similar concern. It argues that the reciprocity provision will prevent non-public utilities from obtaining comparable access. The public utility from which the non-public utility wants access will be able to delay access by claiming that the reciprocity provision is not satisfied. Even the possibility of such a delay may discourage customers from contracting with non-public utilities. SC Public Service Authority suggests that this problem can be fixed by allowing non-public utilities to file comparable access tariffs with the Commission.

NE Public Power District asserts that while government-owned utilities are subject to limited regulation under sections 211–213 of the FPA, ''that limited grant of jurisdiction cannot be transmuted into amenability of state- and municipally owned utilities to the sort of detailed regulation that the NOPR would impose through requiring insertion of so-called 'reciprocity' clauses in the transmission tariffs of jurisdictional public utilities, by inviting the filing of 'class' § 211 applications, or by making adherence to the rules emerging from the NOPR proceeding an automatic requirement for utilities that are subject to a section 211 application.''

NE Public Power District explains that it has pending before the Commission a proceeding in which it has taken the position that it is not subject to the Commission's jurisdiction. (citing Docket No. TX95–3–000).[485] NE Public Power District also argues that it would be unconstitutional under the Tenth Amendment and the Guarantee Clause of the United States Constitution for the Commission to assert jurisdiction. It further argues that the proposed regulations would constitute an unfunded Federal mandate within the meaning of the Unfunded Mandates Reform Act of 1995 and that the Commission has not followed the requirements of that Act.

NE Public Power District explains that under Nebraska law it is prohibited from granting or conveying to any private entity any interest or control of any of its property or facilities, and section 211 does not authorize the Commission to order wheeling for an end-user or to replace a contractual wholesale sale. Thus, it argues that the Commission does not have authority to use mandatory reciprocity clauses to obtain compliance with a policy it has no right to impose directly. (citing *Sunray* and *AGD*). NE Public Power District also questions whether the Commission may lawfully declare exclusive-use provisions invalid under the *Sierra-Mobile* doctrine without conducting a proceeding under section 206 with regard to each specific facility and making the necessary findings.

[485] We note that the application in Docket No. TX95–3–000 by Municipal Energy Agency of Nebraska was withdrawn on November 16, 1995.

Salt River responds to complaints that public power entities have a competitive advantage, due to subsidies and preferences, over investor-owned utilities:

> This Commission is not the appropriate forum and this proceeding is not the appropriate proceeding to consider the investor-owned utilities' ''level playing field'' complaint as it relates to public power, and the Commission should reject any suggestion that it do so.[486]

Cleveland urges the Commission not to address in the NOPR proceeding either congressional policy as reflected in the tax laws or the propriety of other long-standing federal statutes in considering complaints that publicly-owned entities receive subsidies from the government that IOUs do not. It points to three tax breaks available to IOUs: (1) Investment tax credits; (2) deferred taxes resulting from different book and tax depreciation; and (3) use of tax-exempt financing in certain circumstances.

NRECA/APPA argues that the Commission should not, as requested by EEI, address alleged ''undue'' subsidies received by consumer-owned utilities and delve into such subsidy issues as municipal financing policy, rural electrification and development policies, and the merits of privatizing the federal power marketing administration. NRECA/APPA alleges that these are complex issues that are within the domain of other federal agencies.

G&T and Distribution Cooperatives

NRECA explains that under Dairyland Power Cooperative,[487] the Commission does not have jurisdiction over cooperatives that have REA/RUS loans.[488] NRECA further explains that rural electric cooperatives are exempt from federal taxation only if 85 percent of their revenues are derived from their members and open access could jeopardize their tax relief.[489] RUS notes that while the Energy Policy Act expanded the Commission's authority to order transmission access, it did not

[486] Salt River Reply Comments at 2. *See also* NCMPA.

[487] 37 FPC 12, 37 FPC 495 (1967), *aff'd sub nom.* Salt River Project v. FPC, 391 F.2d 470 (D.C. Cir.), *cert. denied,* 393 U.S. 857 (1968).

[488] *See also* Basin EC, Big Rivers EC (citing *Golden Spread,* 39 FERC ¶ 61,322, *reh'g denied,* 40 FERC ¶ 61,348 (1987)), RUS (asserting that RUS has exclusive authority over rural power cooperatives that have RUS loans).

[489] *See also* McKenzie EC, NW Iowa Cooperative, TDU Systems, RUS (asserting that if cooperative voluntarily gives up its tax exempt status, the Commission should allow the related tax expense to be included in the rates charged to the non-member customers only), Brazos, Tri-State G&T, TAPS.

amend the Rural Electrification Act (RE Act) so as to curtail the plenary powers of RUS to carry out a program of rural electrification.

Citing various cases, Brazos says that the Commission must be mindful of the purposes of the RE Act and, if available transmission on Brazos is taken for use by third parties, ''a question remains as to the capacity of the remaining portions of the system to function with 'decent service and at decent rates.' '' [490]

Various rural electric cooperatives state that the Commission must recognize that consumer-owned electric utilities are very different from investor-owned utilities.[491] Mor-Gran-Sou EC is concerned that the final rule will have a detrimental impact on rural areas, just as it believes deregulation of the banking industry, airline industry and telecommunications industry has had.

Many cooperatives request that the term ''affiliates'' be defined: (1) To apply only to corporate ''affiliates'' over which the transmission customer exercises legal control; and (2) to exclude the distribution cooperative members of a generation and transmission (G&T) cooperative.[492] Seminole EC explains that a G&T is a cooperative formed by a group of distribution cooperatives; therefore, a G&T has no legal powers to require action by its member cooperatives. In fact, according to Seminole EC, the distribution cooperatives govern the G&T.

Similarly, TDU Systems notes that the term ''affiliates'' could be construed to apply to a joint action agency and its municipal and cooperative members. TDU Systems point out that a joint action agency, itself a creature of statute, may not have the power to require its members to provide transmission service.

AEC & SMEPA contends that including the transmission customer's affiliates in the reciprocity obligation is broader than the obligation of the transmission provider, which does not include transmission service by the provider's affiliates. AEC & SMEPA suggests that either: (1) The transmission provider's affiliates should be included in the basic obligation to provide transmission service; or (2) the reciprocity provision should delete the reference to affiliates of the transmission customer.

NRECA comments that it is unclear whether ''facilities owned or controlled by the transmission customer'' include transmission contracts. NRECA believes that transmission contracts cannot be included in this definition, at least as applied to ''transmitting utilities'' under sections 211 and 212.

Transmission Provider

Seminole EC questions whether the requirement to offer ''open access'' service requires reciprocal service to be provided solely to the transmission provider or an open access tariff available to any and all qualified applicants. Seminole EC and NRECA request that the Commission adopt the former interpretation in the final rule.

In contrast, Tucson Power and Phelps Dodge believe that, if a non-public utility transmitting entity chooses to take service under any open access tariff, such access should be conditioned on its own agreement to provide comparable service to *all* eligible customers under an open access tariff.

Tucson Power believes that, without such access to all eligible customers, reciprocity will fail to achieve true ''comparability.'' Tucson Power explains that reciprocal transmission service would appear to be limited by the terms of the specific original request for transmission. For example, Tucson Power fears that a non-jurisdictional entity requesting 25 MW of point-to-point firm service could argue that its reciprocal transmission obligation is limited to the same 25 MW of point-to-point firm service for an equivalent duration. Tucson Power argues that such a limitation on providing reciprocal service would prove useless. Further, Tucson Power believes that reciprocity should be interpreted to require a non-public utility entity to expand or upgrade facilities to meet the transmission requests of all eligible entities and should contain the same pricing provisions as applied in this proceeding for jurisdictional utilities.

Seminole EC questions whether the reciprocity requirement to provide ''comparable'' service to the transmission provider simply means offering the same *kind* of service to the transmission provider that the transmission customer receives (i.e., network, firm point-to-point, or non-firm).

NRECA claims that the reciprocity requirement should not be construed to impose on non-public utilities an unreasonable obligation to build. Seminole EC adds that an unreasonable obligation to build could effectively preclude requests for tariff service; the transmission customer could be better off litigating a section 211 request rather than accepting the obligation to undertake a massive construction program.

Commission Conclusion

We conclude that it is appropriate to require a reciprocity provision in the Final Rule pro forma tariff. This provision would be applicable to all customers, including non-public utility entities such as municipally-owned entities and RUS cooperatives, that own, control or operate interstate transmission facilities and that take service under the open access tariff, and any affiliates of the customer that own, control or operate interstate transmission facilities. Any public utility that offers non-discriminatory open access transmission for the benefit of customers should be able to obtain the same non-discriminatory access in return.

In the NOPR, we explained that the reciprocity provision would ''requir(e) any user or agent of the user of the tariff that owns and/or controls transmission facilities to provide non-discriminatory access to the tariff provider.'' [493] We wish to clarify that, in stating that a user must provide non-discriminatory access to the tariff provider, we intend that reciprocal service be limited to the transmission provider. However, in situations in which a non-public utility is a member of an RTG or a power pool, it also would have to provide service to the other members of the RTG or power pool. We do not believe it is appropriate to expand the reciprocity condition beyond these situations at this time because, as discussed further below, the IRS currently is evaluating its tax-exempt financing regulations in light of competitive changes in the industry.

We are aware that many non-public utilities are very willing to offer reciprocal access, and that some are willing to provide access to all eligible customers through an open access tariff. However, they are fearful that a public utility may deny service based simply on a claim that the open access tariff offered by a non-public utility is not satisfactory. To assist these non-public utilities, we have developed a voluntary safe harbor procedure that should alleviate these concerns. Under this procedure, non-public utilities would be allowed to submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. We would post these requests on the Commission Issuance Posting System (CIPS) and would provide them with an NJ (non-

[490] Brazos Initial Comments at 6.

[491] *E.g.*, NW Iowa Cooperative, TDU Systems, Big Rivers EC, Mor-Gran-Sou EC, San Luis Valley REC, Tri-County EC; *see also* RUS, MEAG, Brazos.

[492] *E.g.*, NRECA, Cajun, AEC & SMEPA, Seminole EC, TDU Systems.

[493] FERC Stat. & Regs. at 33,050.

jurisdictional) docket designation. If we find that a tariff contains terms and conditions that substantially conform or are superior to those in the Final Rule pro forma tariff, we would deem it an acceptable reciprocity tariff and would require public utilities to provide open access service to that particular non-public utility.[494] In order to find that a non-public utility's tariff is consistent with our comparability standards, we would need sufficient information to conclude that the non-public utility's rate is comparable to the rate it charges others. In addition, once we find that a tariff is an acceptable reciprocity tariff, an applicant in a section 211 case against a non-public utility would have the burden of proof to show why service to the applicant under the same terms as the reciprocity tariff is not sufficient and why a section 211 order should be granted.

The safe harbor procedures that we have outlined above would be purely *voluntary* for non-public utilities. The procedures are intended to provide non-public utilities an opportunity to confirm that they are willing to provide comparable transmission service. If, however, a non-public utility chooses not to seek a Commission determination that its tariff meets the Commission's comparability standards, a public utility could refuse to provide open access transmission service only if such denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.

In addition to the safe harbor procedures, we note that a non-public utility that is a member of an RTG can meet our comparability standards through the RTG, and can provide an open access tariff that meets our comparability standards by filing a tariff with the administrator of the RTG.[495] Similarly, a non-public utility that is a member of a power pool could meet our comparability standard if the power pool adopts a joint pool-wide open access tariff.

Some commenters have challenged the Commission's jurisdiction to require any non-public utility that takes jurisdictional service to provide reciprocal non-discriminatory transmission services and to unbundle its rates. We are not requiring non-public utilities to provide transmission access. Instead, we are conditioning the use of open access services on an agreement to offer open access services in return. Non-public utilities can choose not to take service under public utility open access tariffs and can instead seek voluntary service from the public utility on a bilateral basis.

In response to arguments raised by publicly-owned utilities and cooperatives, we are not prepared to revise or eliminate the reciprocity condition. Our reason is simple and compelling. We are undertaking this Rule and imposing significant responsibilities on public utilities to ensure the Nation's transmission grid is open and available to customers seeking access to the increasingly competitive commodity market for electricity. While we do not have the authority to require non-public utilities to make their systems generally available, we do have the ability, and the obligation, to ensure that open access transmission is as widely available as possible and that this Rule does not result in a competitive disadvantage to public utilities. Non-public utilities, whether they are selling power from their own generation facilities or reselling purchased power, have the ability to foreclose their customers' access to alternative power sources, and to take advantage of new markets in the traditional service territories of other utilities. While we do not take issue with the rights these non-public utilities may have under other laws, we will not permit them open access to jurisdictional transmission without offering comparable service in return. We believe the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the non-public utility seeks to take advantage of open access on a public utility's system. However, we recognize that Congress has determined that certain entities in the bulk power market can utilize tax-exempt financing by issuing bonds that do not constitute ''private activity bonds'' [496] or by financing facilities with ''local furnishing'' bonds.[497] In both circumstances, Congress has entrusted the Internal Revenue Service (IRS) with the responsibility for implementation and for determining what uses of the facilities are consistent with maintaining tax-exempt status for bonds used to finance such facilities. It is not our purpose to disturb Congress's and the IRS's determinations with respect to tax-exempt financing.

We are encouraged that the IRS is presently reconsidering its private activity bond regulations in light of, among other things, the changing circumstances in the electric industry, including this proceeding.[498] We are hopeful that the IRS in its rulemaking will, to the maximum extent possible, remove regulatory impediments that limit the ability of industry participants to provide reciprocal open access service. Until that occurs, however, we believe we must ensure that the reciprocity requirement will not be used to defeat tax-exempt financing authorized by the Congress. Therefore, we clarify that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities.[499] If a non-public utility has sought a declaratory order on a voluntarily-filed tariff, we request that it identify the services, if any, that it cannot provide without jeopardizing the tax-exempt status of its financing.[500]

We believe, given the fact that the IRS is currently examining these issues, that our policy in this regard is appropriate for the time being. After the IRS acts, we will reexamine our policy to ensure that the reciprocity requirement is applied broadly to achieve open access without jeopardizing tax-exempt financing.

With respect to local furnishing bonds, which are available to a handful of public utilities, we note that Congress, in section 1919 of the Energy Policy Act, amended section 142(f) of the Internal Revenue Code to provide that a facility shall not be treated as failing to meet the local furnishing requirement by reason of transmission services ordered by the Commission under section 211 of the FPA if ''the portion of the cost of the facility financed with tax-exempt bonds is not greater than the portion of the cost of the facility which is allocable to the local furnishing of electric energy.'' [501] San Diego G&E has included in its existing transmission tariff a provision

[494] Public utilities would also be required to provide service during the pendency of any request for declaratory order. Otherwise, public utilities could continue to delay providing service.

[495] *See, e.g.*, Southwest Regional Transmission Association, 73 FERC ¶ 61,147 at 61,414 (1995).

[496] *See* 26 U.S.C. 141.

[497] *See* 26 U.S.C. 142.

[498] Definition of Private Activity Bonds, 59 FR 67658 (December 30, 1994), Proposed Rules (to be codified at 26 CFR pt. 1).

[499] The same would be true in the case of a G&T cooperative that is a tax-exempt entity under section 501(c)(12) of the Internal Revenue Code (26 U.S.C. 501(c)(12)) that would risk loss of tax-exempt status if more than 15 percent of its revenues are derived from business with non-members. We clarify that reciprocal service will not be required if providing such service would jeopardize the G&T cooperative's tax-exempt status.

[500] A tariff offered by a non-public utility transmission provider to satisfy the reciprocity requirement may include a provision permitting the transmission provider to refuse service if providing such service would jeopardize its tax-exempt status or the tax-exempt status of its bonds. The non-public utility could file a declaration to this effect in an NJ docket.

[501] 26 U.S.C. 142(f)(2)(A).

that provides that, if it appears that the provision of transmission service would jeopardize the tax-exempt status of any local furnishing bonds used to finance its facilities, San Diego G&E will not contest the issuance of an order under section 211 of the FPA requiring the provision of such service, and will, within 10 days of receiving a written request by the applicant, file with the Commission a written waiver of its rights to a request for service under section 213(a) of the FPA and to the issuance of a proposed order under section 212(c).[502] We believe such a provision is necessary and appropriate so that any local furnishing bonds that may exist do not interfere with the effective operation of an open access transmission regime. Accordingly, we will require any public utility that is subject to the Open Access Rule that has financed transmission facilities with local furnishing bonds to include in its tariff a similar provision.[503]

In addition, in response to arguments raised by cooperatives and joint action agencies, we agree to limit the reciprocity requirement to corporate affiliates. If a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, would be required to offer transmission service. However, if a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its G&T cooperative) must offer reciprocal transmission service over its interstate transmission facilities.

Finally, a non-public utility, for good cause shown, may file a request for waiver of all or part of the reciprocity requirement. We would apply the same criteria we will use to determine whether to grant a waiver of all or part of the Final Rule's requirements for public utilities that request waiver.

The reciprocity requirement will also apply to any entity that owns, controls or operates transmission facilities that uses a marketer or other intermediary to obtain access. For example, if a municipal purchases power from a marketer that also arranges for the transmission of the power through a public utility open access tariff to the municipal, the municipal would need to meet our reciprocity requirements. We point out here that we have established a procedure, set out in Section IV.K.2., for small public utilities to request a waiver from some or all of the requirements of the Rule. We would apply the same criteria to waive the reciprocity condition for small non-public utilities.

g. Miscellaneous Tariff Modifications

(1) Ancillary Services

The pro forma tariff, attached as Appendix D, incorporates conforming revisions consistent with the determinations discussed in Section IV.D.

(2) Clarification of Accounting Issues

Comments

A number of commenters generally assert that, as presently configured, the Commission's Uniform System of Accounts does not support the proposed stranded cost and open access policies set forth in the NOPR. They urge the Commission to open a separate docket to address these accounting issues and bring together all parties to properly resolve them. More specifically, commenters ask whether certain of the requirements outlined in the NOPR pro forma tariffs would require changes to the Uniform System of Accounts. In particular, commenters are concerned that the recording of costs and revenues related to ancillary services, facilities studies, and system impact studies would require the creation of new accounts under the Uniform System of Accounts. In addition, commenters raise questions about the procedures transmission providers would have to follow for recording the costs for their own use of the system. Commenters also indicate that the Commission's accounting requirements may not be adequate to provide fully for the recognition of stranded costs as contemplated in the NOPR.

Commission Conclusion

The Final Rule will result in significant changes in the way public utilities conduct business. This will create needs for financial information that are different from those that the Commission and others found necessary in the past. The Commission believes that the accounting guidance discussed *infra* will be sufficient to provide the financial information needed for regulatory purposes in light of this Rule. Therefore, we will not institute a separate proceeding to propose changes to our Uniform System of Accounts at the present time. We recognize, however, that the industry is in an early stage of transition to an environment in which truly comparable transmission services will be provided to all wholesale users. If, after gaining additional experience, it becomes apparent that more guidance is needed, additional guidance can be provided at that time through issuance of accounting interpretations, guidance letters, or a notice of proposed rulemaking to change our accounting regulations.

Many of the accounting concerns expressed by commenters were addressed in the Chief Accountant's January 26, 1996 guidance letter. We offer the following additional clarifications on the Final Rule pro forma tariff requirements and certain other accounting issues related to the Final Rule.

(a) Transmission Provider's Use of Its System (Charging Yourself)

The purpose of functional unbundling is to separate the transmission component of all new transactions occurring under the Final Rule pro forma tariff, thereby assisting in the verification of a transmission provider's compliance with the comparability requirement. For example, if a transmission provider makes an off-system power sale, functional unbundling requires that the revenues received from that third-party customer be unbundled into specific transmission and production components. The transmission component of the revenues would be the product of the amount of transmission capacity used in making the sale and the applicable rate. With respect to off-system sales, the transmission provider would look to operating revenue accounts those revenues received from the customer to whom it made the off-system sale. We will require that the transmission service component and energy component of those revenues be recorded in separate subaccounts of Account 447, Sales for Resale.

(b) Facilities and System Impact Studies

Comparability mandates that to the extent a transmission provider charges transmission customers for the costs of performing specific facilities or system impact studies related to a service request, the transmission provider also must separately record the costs associated with specific studies undertaken on behalf of its own native load customers, or, for example, for making an off-system sale. Utilities choosing this method of recovering the cost of specific studies must keep detailed expense records pertaining to each specific study. We will require utilities to record the cost of such studies that are properly includable in the determination of net income for the

[502] *See* San Diego Gas & Electric Company, Docket No. ER96–43–000, Pro-Forma Point-to-Point Transmission Service Tariff, section 4.6(d); Network Transmission Service Tariff, section 4.7(d).

[503] *See* Appendix D, Pro Form Open Access Transmission Tariff, Section 5.

period in a separate subaccount of Account 566, Miscellaneous Transmission Expenses. We note, however, that not all studies performed by a transmission provider will benefit only a single customer. To the extent a transmission provider performs a system impact study that is useful in providing service to all transmission customers, the costs should be allocated to all customers.

(c) Ancillary Services

To ensure comparable transmission access a transmission provider is obligated to provide, or offer to provide, certain ancillary services to the transmission customer. Also, the transmission provider may offer to provide other ancillary services to the transmission customer, as discussed in Section IV.D. A transmission customer is obligated to purchase certain ancillary services from the transmission provider.

Generation resources provide certain ancillary services, while transmission resources provide other ancillary services. Consequently, the costs of providing certain ancillary services are recorded in the transmission provider's power production expense accounts,[504] while others are recorded in the transmission provider's transmission expense accounts.

Some commenters suggest that there may be a need for revising the Uniform System of Accounts to better track the costs of providing discrete ancillary services. Other commenters believe that ancillary services are transmission-type services and suggested that the costs of generation-provided ancillary services be refunctionalized from power production expense to transmission expense.

Currently, the Uniform System of Accounts requires that costs incurred in providing ancillary services are recorded as power production or transmission expense depending upon which resource the transmission provider uses to supply the service. At this time, we are not convinced that the amounts involved or the difficulty associated with measuring the cost of ancillary services warrants a departure from our present accounting requirements. However, in calculating separate rates for specific ancillary services utilities must maintain sufficient records and cost support for the derivation of the rates. Additionally, we will specify that the revenues a Transmission Provider receives from providing ancillary services must be recorded by type of service in Account 447, Sales for Resale, or Account 456, Other Electric Revenues, as appropriate.

(3) Liability and Indemnification

Comments

A number of commenters addressed the liability and indemnification provisions of the proposed pro forma tariffs. Duke argues that the proposed language confuses and conflates the limitation on the Transmission Provider's and Customer's rights against each other if a force majeure event occurs, and the requirement of indemnification against claims by third parties.

EEI argues that the proposed indemnification provision is inappropriate because it applies both ways, that is, the Transmission Provider and Customer indemnify each other against third party claims arising on their own systems. EEI suggests that the provision, as written, could result in the utility being required to indemnify the customer against damages incurred if, for example, an individual pried open a transformer to steal materials and in the process was electrocuted. This concern was also voiced by Consolidated Edison, NYSEG, and Virginia Electric and Power Company. Consumer Power suggests that the best answer to this issue may be to leave the issue of allocation of risk to the contracting parties, to be resolved by negotiation when a Service Agreement is drawn up.

The Coalition for a Competitive Market, on the other hand, argues that the indemnification provision, as proposed, provides too much of a limitation of the Transmission Provider's liability, requiring gross negligence rather than simple negligence before the Transmission Provider can be held liable for damages to third parties arising from the Transmission Provider's actions.

Commission Conclusion

We agree with the commenters that these risk allocation provisions must be carefully drafted so that transmission providers and customers can accurately assess and account for their respective risks. The indemnification provision has now been broken into two parts. The first part is a force majeure provision which provides that neither the transmission provider nor the customer will be in default if a force majeure event occurs, but also provides that both the transmission provider and customer will take all reasonable steps to comply with the tariff despite the occurrence of a force majeure event. This protection against unexpected and unpredictable events is appropriately made available to both the transmission provider and transmission customer.

The second portion of the provision provides for indemnification against third party claims arising from the performance of obligations under the tariff. We have limited the indemnification portion of the provision so that it is now only the transmission customer who indemnifies the transmission provider from the claims of third parties. The customer is taking service from the transmission provider and may appropriately be asked to bear the risks of third-party suits arising from the provision of service to the customer under the tariff. We find that this new indemnification provision would be too strict if it required customers to indemnify transmission providers even in cases where the transmission provider is negligent. *See Pacific Interstate Offshore Company,* 62 FERC ¶ 61,260 at 62,733–34 (requiring amendment of indemnification provisions that required indemnification except in cases of "gross negligence"). Accordingly, the revised provision provides that the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.

(4) Miscellaneous Clarifications

(a) Electronic Format

In the NOPR, we proposed that public utilities making Stage Two filings be required, in addition to the requirements specified in Part 35, to file copies of such filings on a diskette in ASCII format. We will now require that public utilities, in addition to complying with the requirements of Part 35, submit a complete electronic version of all transmission tariffs and service agreements in a word processor format, with the diskette labeled as to the format (including version) used, initially and each time changes are filed. After the initial compliance filing, utilities proposing changes to the Final Rule pro forma tariff terms and conditions must provide a detailed list of changes and, to the extent practicable, provide an electronic version that reflects changes in redline/strikeout format.

(b) Administrative Changes

A number of commenters request tariff modifications of an administrative nature. We have adopted many of these recommendations. Due to the nature of these changes, we feel that no further

[504] This discussion applies to vertically integrated transmission providers. It may not apply, for example, to a transmission-only company or an independent system operator.

explanation is necessary. The tariff modifications include the following:

Part I—Common Service Provisions

Description

• Added definition for Curtailment.
• Modified definition for Good Utility Practice.
• Added definition for Interruption.
• Added definition for Load Shedding
• Added definition for Long-Term Firm Point-to-Point Transmission Service.
• Added definition for Third-Party Sale.
• Modified provision for Interest on Unpaid Balances to include amounts placed in escrow.
• Modified provision for Customer Default to not require termination of service.
• Deleted contradictory language from the provision for Rights Under the Federal Power Act.
• Deleted references to Valid Request throughout the tariff.

Part II—Point-To-Point Transmission Service

Description

• Added language that multiple generating units at one site are considered one point of receipt.
• Changed the time to file an unexecuted service agreement from 10 days to 30 days.
• Changed the time to execute a service agreement from 30 days to 15 days.
• Deleted charge for scheduling changes.
• Deleted redundant language on study agreements.
• Changed standards for estimates from binding to good faith.
• Clarified that schedules of energy submitted to the delivering party will equal the schedules of energy submitted by the receiving party unless reduced for losses.
• Clarified that the term of non-firm point-to-point transmission service need not expire before the customer may submit another application for service.
• Added language for rate treatment in the instance when a customer uses more non-firm point-to-point transmission service than it has reserved.
• Clarified Deposit provision to permit return of deposit at expiration of service agreement rather than crediting the deposit against unspecified customer obligations under the tariff.
• Clarified provision for Yearly Extensions for Commencement of Service.
• Clarified provision for Reservation of Non-Firm Point-to-Point Transmission Service.
• Modified provision for customer Power Factor to permit mutually agreeable alternatives to maintaining a specified power factor.

Part III—Network Integration Transmission Service

Description

• Deleted redundant Direct Assignment provision.
• Added language to clarify that a transmission customer does not have to use the transmission provider's point-to-point transmission service if the sales to non-designated loads do not use the transmission provider's system.
• Modified Transmission Customer Redispatch Obligation to limit the redispatch obligation to reliability reasons.
• Deleted Member System requirement from network service.
• Deleted redundant General Conditions.
• Added provision to return application if customer does not remedy deficiency.
• Deleted redundant language for designating new network resources.
• Deleted redundant language for connecting new member systems.
• Deleted redundant language for new interconnection points.
• Added a 60 day period for initial applications consistent with the point-to-point service provision. (If applications during this period exceed available capacity, they are considered simultaneous requests and service will be decided based on a lottery.)
• Modified System Impact Study provision.
• Added 30 day turnaround for Facilities Study Agreement and changed estimates from binding to good faith.
• Deleted redundant language for adding new network resources.
• Added language for rate treatment in the instance when a customer fails to curtail or shed load.
• Deleted redundant language from Network Operating Committee.

H. Implementation

The Commission proposed in the NOPR a two-stage implementation process that would apply to all transmission-owning public utilities that do not have non-discriminatory open access transmission tariffs on file on the effective date of the final rule. As proposed in the NOPR, public utilities already in compliance with the rule would not be subject to the two-stage process.

In Stage One, the Commission proposed to put into effect tariffs for network and point-to-point services, which include ancillary transmission services. These tariffs would specify the minimum terms and conditions of service needed to eliminate undue discrimination, and were proposed to be effective 60 days after the effective date of the final rule. Because the proposed pro forma tariffs did not contain specific rates, the Commission proposed to itself establish, for each affected public utility, just and reasonable rates for network service, point-to-point service, and six identified ancillary services. These rates were to be incorporated into each utility's tariffs.

In Stage Two, which was to begin 61 days after the effective date of the final rule, parties would have been allowed to propose changes to the rates, terms, and conditions for service under utilities' transmission tariffs pursuant to sections 205 and 206 of the FPA.

Comments

The commenters are split on the two-stage implementation procedure proposed in the NOPR. Commenters in favor of the proposed procedure believe that a two-stage process is necessary to put basic open access tariffs in place without delay.[505] Florida Power Corp and NIEP state that a longer implementation procedure would create a discriminatory situation for utilities that have filed open access tariffs versus those that have not. Other commenters, however, contend that the proposed Stage One rates would be just and reasonable only as an interim measure; therefore, the period during which such rates are effective should be limited.[506]

Those commenters that oppose the two-stage implementation process do so for a variety of reasons.[507] Many transmission customers believe that Stage One rates will be much higher than the rates they pay now. Several commenters warn that the implementation plan may not be practical if the Commission is inundated with filings at the beginning of Stage Two.[508] Some commenters expressing concerns about transmission pricing policy believe that in the NOPR the Commission intended to establish the Stage One rate method as its own

[505] *E.g.*, ABATE, CO Com, DOE, Florida Power Corp, IBM, IL Com, MN DPS, Industrial Energy Applications, Missouri-Kansas Industrials, NIEP, ND Com, PG&E, PSNM, SBA, SC Public Service Authority, TDU Systems.

[506] *E.g.*, SC Public Service Authority.

[507] *E.g.*, Dayton, Carolina P&L, Citizens Utilities, Montana Power, Oglethorpe, OK Com, Seattle, Seminole EC, St. Joseph, Turlock, WA Com.

[508] *E.g.*, Christensen, Seminole EC.

official pricing policy, while other commenters argue that the Stage One rates demonstrate that broad pricing policy reform is needed as part of an open access rule.

Some commenters express concern about the timing of Stage One. Carolina P&L complains that the proposed implementation date is far too aggressive and proposes a one-year delay between the final rule and its implementation. Montana Power states that Stage One tariffs cannot be implemented in 60 days if any sort of functional unbundling is required. It insists that utilities should be given, at a minimum, 180 days in which to hire and train new employees and to install new equipment. Dayton P&L believes that Stage One tariffs should not be imposed until experience is gained with voluntarily-filed open access tariffs, but recommends further development of the tariffs for guidance purposes. It also requests that the Commission delay implementation of mandatory open access transmission until meaningful appellate review has taken place. Seattle suggests that the rate determination methods be phased in, so that the forced filing of transmission tariffs does not cause immediate and major shifts in cost allocation between old and new customers.

A few commenters express concern about the applicability of the implementation process. EEI and Consumers Power state that utilities that have already filed open access tariffs should have the option to use the two-stage implementation procedure so that they can obtain the terms and conditions of the NOPR tariffs without having to make a full-blown rate case filing.

Citizens Utilities asks that small distribution public utilities be exempt from Stage One if such entities can demonstrate that they do not use their own transmission systems to provide network service. Alternatively, it asks that application of Stage One to small public utilities be deferred until 60 days after they receive a section 211 request. Oglethorpe states that the proposed method of Stage One pricing is not appropriate for electric cooperatives that receive financing from the Rural Utilities Service (formerly the Rural Electrification Administration).

Commission Conclusion

In light of the many concerns raised regarding the proposed implementation process, the need to have adequate open access tariffs on file for all public utilities as soon as possible, the large number of utilities that have already filed some form of open access tariffs, and the desire to give public utilities flexibility to propose their own rates to be used in conjunction with the minimum non-rate terms and conditions necessary to ensure comparable service, we have decided to modify our proposed procedures. The details of the revised procedures are discussed below. In addition, special implementation requirements for coordination arrangements (power pools, public utility holding companies, and bilateral coordination arrangements) are discussed in Section IV.F.

The Revised Procedures

Implementation of the Rule will vary slightly for those public utilities that tendered for filing open access tariffs before the date of issuance of this Rule (including newly-tendered applications that have not been accepted for filing before the issuance of this rule) and those public utilities that did not tender open access tariffs before the issuance of this Rule. The former group is hereinafter referred to as Group 1 public utilities, while the latter group is referred to as Group 2 public utilities.

1. Group 1 Public Utilities

Group 1 public utilities will be required, within 60 days following publication of the Final Rule in the Federal Register, to make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below. Attached as Appendix E to this Rule is a list of Group 1 public utilities.

As to rates, we note that a transmission tariff rate is already in effect for all Group 1 public utilities, except for the few with recently-tendered applications that have not yet been accepted for filing. Most of these rates have been suspended, accepted for filing, set for hearing, and made subject to refund. Some have been accepted outright. Still others are the product of rate settlements.

We anticipate that our mandated changes in non-rate terms and conditions are compatible with the rate proposals already filed by Group 1 public utilities. Consequently, we are not going to divert the industry's resources by mandating any rate changes to fine-tune these interim tariffs. Should, however, a Group 1 public utility determine that certain rate changes are necessitated by the revised non-rate terms and conditions, it may file a new rate proposal under FPA section 205. Such filings must be ''conforming'' [509] under the Transmission Pricing Policy Statement and must be made no later than 60 days after publication of the Final Rule in the Federal Register. Intervenors may raise any concerns with the filings within 15 days after such filings.[510] We hereby impose a blanket suspension for any filings by Group 1 public utilities proposing rate changes necessitated by the new non-rate terms and conditions. These rates will go into effect, subject to refund, 60 days after publication of this Rule in the Federal Register (the same day on which the non-rate terms and conditions of the Final Rule pro forma tariff go into effect).[511]

If the Final Rule tariff's non-rate terms and conditions do not in the opinion of the utility necessitate a change in current rates, then the current rates will continue in effect under whatever refund conditions, if any, now apply to those rates.

2. Group 2 Public Utilities

Group 2 public utilities will be treated the same as Group 1 public utilities with regard to non-rate terms and conditions, but will be treated slightly differently from Group 1 as to rates, since Group 2 utilities have not filed any proposed rates. We will require these utilities to *either:* (i) Within 60 days following publication of the Final Rule in the Federal Register, make section 206 compliance filings that contain the non-rate terms and conditions set forth in the Final Rule pro forma tariff and identify any terms and conditions that reflect regional practices, as discussed below; and (ii) within 60 days following publication of the Final Rule in the Federal Register, make section 205 filings to propose rates for the services provided for in the tariff, including ancillary services; *or* (iii) make a ''good faith'' request for waiver. The rates must meet the standards for conforming proposals in the Commission's Transmission Pricing Policy Statement and comply with the guidance concerning ancillary services set forth in this order. Attached to this

[509] As described in the Transmission Pricing Policy Statement, a ''conforming'' proposal is one that meets the traditional revenue requirement and reflects comparability. FERC Stats. & Regs. ¶ 31,005 at 31,141.

[510] Given the brief comment period on the compliance filings, we will require public utilities to serve copies of their compliance filings (via overnight delivery) on: all participants in their current open access rate proceedings (if applicable); all customers that have taken wholesale transmission service from the utility after the date of issuance of the Open Access NOPR; and the state agencies that regulate public utilities in the states of those participants and customers.

[511] The Commission retains the right to reject such rates or to set them for hearing.

Rule as Appendix F is a list of Group 2 public utilities.

Intervenors may raise any concerns with these filings within 15 days after the filing.[512] We hereby impose a blanket suspension for all such rate filings; they will go into effect, subject to refund, 60 days after the publication of this Rule in the Federal Register (the same day on which the terms and conditions of the compliance tariffs go into effect).[513]

3. Clarification Regarding Terms and Conditions Reflecting Regional Practices

We have built a degree of flexibility into the tariffs to accommodate regional and other differences. Certain non-rate Final Rule pro forma tariff provisions specifically allow utilities either to follow the terms of the provision or to use alternatives that are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider (*e.g.*, time deadlines for scheduling changes, time deadlines for determining available capacity). In addition, other tariff provisions require utilities to follow Good Utility Practice. The definition of ''Good Utility Practice,'' contained in Section 1.14 of the Final Rule pro forma tariff, states that it ''is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.'' Thus, where public utilities are permitted to follow regional practices, and elect to do so within 60 days of the date of publication of the Final Rule in the Federal Register, they should identify the regional practices in their compliance tariff filings.

4. Future Filings

We recognize that there may be circumstances in which a public utility believes that the Final Rule pro forma tariff does not provide sufficient flexibility or that the utility can propose superior non-rate terms and conditions. Thus, once the compliance tariff and conforming rates go into effect, which will be 60 days after publication of this Rule in the Federal Register, a public utility (either Group 1 or Group 2) may file pursuant to section 205 a tariff with terms and conditions that differ from those set forth in this Rule, provided that it: (1) Serves a copy of its filing on all wholesale customers for whom it has provided transmission service since March 29, 1995 (the date of the Open Access NOPR) and on the state agencies that regulate public utilities in the states where those customers are located; (2) identifies all deviations from its compliance tariff in its letter of transmittal; (3) provides, to the extent practical, a redlined version of the tariff; and (4) demonstrates that such terms and conditions are consistent with, or superior to, those in the compliance tariff. However, it may not seek to litigate fundamental terms and conditions set forth in the Final Rule.[514] In addition, the public utility may file whatever rates it believes are appropriate, consistent with the Transmission Pricing Policy Statement.

5. Waiver

Finally, as noted above, several commenters propose that public utilities that own few transmission facilities be granted waiver, or that application of the Rule to such utilities be deferred until 60 days after they receive a section 211 request. As discussed more fully in Section IV.K.2., we find that it is reasonable to permit certain public utilities for good cause shown to file, within 60 days after this Rule is published in the Federal Register, requests for waiver from some or all of the requirements of this Rule. The filing of a request in good faith for a waiver from the requirement to file an open access tariff will eliminate the requirement that such public utility make a compliance filing unless thereafter ordered by the Commission to do so. It will not, however, exempt such public utility from providing, upon request, transmission services consistent with the requirements of the Final Rule.

I. Federal and State Jurisdiction: Transmission/Local Distribution. In the original Stranded Cost NOPR, the Commission clarified that it has exclusive jurisdiction over unbundled retail transmission in interstate commerce by public utilities: it found that the Commission has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, up to the point of local distribution. In the Open Access NOPR, the Commission reaffirmed this jurisdictional determination[515] and also addressed the distinction between transmission and local distribution. The Commission stated three reasons for expressing its views on the distinction between Commission-jurisdictional transmission in interstate commerce and state-jurisdictional local distribution, in the context of unbundled retail wheeling by public utilities.[516] First, facilities that can be used for wholesale transmission in interstate commerce by a public utility would be subject to the Commission's open access requirements. Second, states have authority to address retail stranded costs and stranded benefits through their jurisdiction over facilities used in local distribution. Third, as the structure of the industry continues to change dramatically, utilities need to know which regulator has jurisdiction over which facilities and services in order to meet state and federal filing requirements. Accordingly, the NOPR set forth our jurisdictional analysis and several technical factors, for determining what constitutes ''facilities used in local distribution.''

For unbundled wholesale wheeling, the NOPR proposed to apply a functional test, *i.e.*, whether the entity to whom the power is delivered is a lawful reseller. For unbundled retail wheeling, the NOPR proposed to apply a combination functional-technical test that would take into account technical characteristics of the facilities used for the wheeling. The Commission proposed seven indicators of local distribution to be evaluated on a case-by-case basis:

[512] Group 2 public utilities must serve a copy of their filings (via overnight delivery) on all customers that have taken wholesale transmission service from them since March 29, 1995 (the date of issuance of the Open Access NOPR) and on the state agencies that regulate public utilities in the states where those customers are located.

[513] *But see* note 510, *supra.*

[514] As we stated in our ''Further Guidance Order,'' American Electric Power Service Corp., 71 FERC ¶ 61,393, 62,539–40, *order on rehearing*, 72 FERC ¶ 61,287, *order on rehearing,* 74 FERC ¶ 61,013 (1995), all tariffs need not be ''cookie-cutter'' copies of the Final Rule tariff. Thus, under our new procedure, ultimately a tariff may go beyond the minimum elements in the Final Rule pro forma tariff or may account for regional, local, or system-specific factors. The tariffs that go into effect 60 days after publication of this Rule in the Federal Register will be identical to the Final Rule pro forma tariff; however, public utilities then will be free to file under section 205 to revise the tariffs, and customers will be free to pursue changes under section 206.

[515] That determination included the situation in which a former bundled retail customer may need unbundled wheeling services from its previous public utility generation supplier, as well as unbundled wheeling from one or more intervening public utilities, in order to reach a distant generation supplier. In that scenario, the Commission would have jurisdiction over all of the transmission facilities used for the unbundled wheeling provided by the intervening public utilities. The NOPR also noted that the Commission would not have jurisdiction over the rates for the sale of generation by the distant supplier because the transaction would be a retail sale. FERC Stats. & Regs. ¶ 32,514 at 33,144.

[516] The term ''wheeling'' is intended to cover any delivery of electric energy from a supplier to a purchaser, i.e., transmission, distribution, and/or local distribution. The Commission also has jurisdiction to order wholesale transmission services in either interstate or intrastate commerce by transmitting utilities that are not also public utilities. See Tex-La Electric Cooperative of Texas, Inc., 67 FERC ¶ 61,019 (1994), reh'g pending.

(1) Local distribution facilities are normally in close proximity to retail customers.

(2) Local distribution facilities are primarily radial in character.

(3) Power flows into local distribution systems; it rarely, if ever, flows out.

(4) When power enters a local distribution system, it is not reconsigned or transported on to some other market.

(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.

(6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.

(7) Local distribution systems will be of reduced voltage.[517]

The NOPR concluded that the application of these tests will enable states to address stranded costs by imposing an exit fee on departing retail customers, or including an adder in the retail customers' local distribution rates.[518]

In the NOPR, the Commission also addressed buy-sell transactions in which an end user arranges for the purchase of generation from a third-party supplier and a public utility transmits that energy in interstate commerce and re-sells it as part of a ''nominal'' bundled retail sale to the end user. We explained that the retail sale is actually the functional equivalent of two unbundled sales (one transmission and the other the sale of power) and that we have exclusive jurisdiction over the voluntary sale by public utilities of unbundled transmission at retail in interstate commerce.[519]

Comments

Several commenters support the Commission's proposed jurisdictional demarcation.[520] San Diego G&E states that the Commission correctly proposed to look at both functional factors (such as whether the service is retail or wholesale) and technical factors (such as voltage). PG&E states that the NOPR's functional/technical test is preferable to a bright line voltage test.

Consumers Power states that the Commission has exclusive jurisdiction over all wheeling on an interconnected interstate transmission grid. It suggests that the Commission and the states act through a joint board or hearing to resolve jurisdictional differences and develop a bright line test.

PSE&G and PG&E express concern that if retail wheeling is implemented, there may be loopholes that would enable customers to evade state jurisdiction and thus avoid paying stranded costs. For example, PSE&G is concerned that a retail customer may request transmission service only and a state commission will be unable to attach a retail stranded cost surcharge to that customer. PG&E proposes adding another indicator to the functional/technical test—a final tap to a retail customer—to ensure that ''high-voltage'' retail customers do not evade the state's reach. Moreover, to ensure that retail customers cannot escape state jurisdiction, PG&E recommends that the Commission state, as a matter of policy, that ''*all* retail customers taking retail transmission service from their host utility *by definition* take service over local distribution facilities.''

CINergy agrees with the Commission that a distinction between transmission and local distribution is important, but emphasizes the practical need for clarity on a timely basis. To achieve certainty, CINergy proposes that the Commission allow public utilities to file, under section 205, classifications of their facilities as transmission or local distribution. CCEM endorses CINergy's proposal. Although NARUC disagrees that the Commission has jurisdiction over unbundled retail transmission, if the Commission reaffirms the NOPR regarding its jurisdiction, then NARUC supports CINergy's proposal.

PSE&G strongly supports the Commission's proposed case-by-case methodology for determining whether facilities should be classified as transmission or local distribution. SoCal Edison argues that since a utility may have difficulty determining which of its facilities are transmission and which are local distribution, utilities and states should be able to ask the Commission to classify a particular facility. Portland and Orange & Rockland suggest that the Commission provide a forum to resolve disputes over the correct classification of particular facilities.

Ohio Edison states that the Commission should assume jurisdiction over unbundled retail transmission, but only where a state has required this unbundling. It also believes that the Commission should assert jurisdiction over the ancillary services necessary to provide this jurisdictional service.

NYSEG argues that the Commission lacks jurisdiction over the transmission component of bundled retail service. On the other hand, NYSEG argues that the statute, legislative history, and case law reveal that the Commission has jurisdiction over unbundled retail wheeling from source to load, since it is transmission in interstate commerce. NYSEG argues that the ''local distribution'' exception to the Commission's jurisdiction applies only to bundled sales of power at retail.

Several state commissions assert that states have rate authority over all facilities used to provide retail service.[521] IL Com argues that states have rate authority over all facilities used to provide retail service, regardless of whether the NOPR would classify these facilities as transmission or local distribution.

MI Com, citing *Connecticut Light & Power Company* v. *Federal Power Commission,* 324 U.S. 515 (1945) (*CL&P*), and *Arkansas Electric Cooperative* v. *Arkansas Public Service Commission,* 461 U.S. 375, 393–94 (1983), contends that states have plenary jurisdiction over all aspects of retail service, including retail access and unbundled retail transmission service. It asserts that the Commission's effort to expand federal jurisdiction into transmission in connection with retail sales is without statutory justification.

Legal Environmental Assistance argues that the NOPR creates confusion about, and may intrude onto, state jurisdiction. NYMEX argues that when a state orders retail wheeling, the state should have jurisdiction over that transmission-only service.

Oklahoma G&E, citing *CL&P* and *United States* v. *California Public Utilities Commission,* 345 U.S. 295, 316 (1953), asserts that the Commission failed to explain that the term ''transmission in interstate commerce'' could have different meanings depending on the factual context in which the term is applied. It argues that ''transmission in interstate commerce'' means the movement, in bulk, of electric energy flowing in interstate commerce, as opposed to the movement of electric energy that has been subdivided for delivery to consumers.

Oklahoma G&E further argues that ''[t]he distinction between interconnected operation and radial operation corresponds precisely to this distinction between activities that have potential interstate effects and those that might have interstate effects but are a matter of primarily local concern.'' [522] Oklahoma G&E also disagrees that the transportation of electric energy sold at wholesale necessarily constitutes transmission in interstate commerce. It argues that the Commission has

[517] FERC Stats. & Regs. ¶32,514 at 33,145.

[518] *Id.* at 33, 144–45.

[519] As discussed *infra,* there also would be a component of local distribution in such a transaction that would be subject to state jurisdiction.

[520] *E.g.,* PG&E, Wisconsin Coalition, Com Ed.

[521] *E.g.,* NM Com, NC Com, AZ Com.

[522] Oklahoma G&E Initial Comments at 16.

misapplied case precedent and, by focusing on the level of the associated power sale, the Commission has misunderstood what constitutes a functional distinction between transmission in interstate commerce and local distribution.

NY Com asserts that the grant of jurisdiction to the Commission over wholesale power transactions in interstate commerce under section 201 of the FPA does not reduce the states' authority over local distribution (citing *CL&P* and *Federal Power Commission* v. *Florida Power & Light Company,* 404 U.S. 453, 467 (1972)). NY Com argues that the NOPR's assertion of exclusive jurisdiction over all facilities used to deliver electricity for resale, even those traditionally regarded as local distribution, violates Congress' assignment of local electric distribution to the states. It takes issue with the Commission's list of factors and says that states and the Commission should agree on a definition that preserves the traditional classification of local distribution facilities. According to NY Com, such definition should focus on the functional characteristics of local electric systems—*i.e.*, electricity flows into a comparatively restricted geographic area and does not flow back out of that area, and the power is consumed in that area.

NY IOUs argue that the Commission has jurisdiction over unbundled, but not bundled retail wheeling. It says that other factors, including the indicators listed in the NOPR, are irrelevant, and that even long-distance interstate transmission is under state jurisdiction as long as it is bundled with a retail sale. According to NY IOUs, this is the plain meaning of the FPA; resort to legislative history is unnecessary. NY IOUs bases this view on section 201(a), which says that federal regulation extends only to matters not subject to state regulation. NY IOUs says that the only matters subject to state regulation were bundled retail sales, and that since transmission was part of the bundle, Congress intended transmission to stay under state authority as long as it is part of that bundle. It also cites section 201(b), which sets forth exceptions from Commission jurisdiction, and section 201(c), which defines ''transmission in interstate commerce'' and thus also controls the definition of transmission in intrastate commerce. Finally, NY IOUs argues that the legislative history supports its view, as does the case law.

Central Louisiana believes that the costs of requiring a transmission provider to take unbundled transmission service for both wholesale and retail purposes would far exceed any benefits. In this regard, Central Louisiana says that states clearly have jurisdiction over bundled retail transmission charges and that the proposed approach could not be implemented without states giving up jurisdiction or the passage of new federal legislation.

MN DPS disagrees on legal and policy grounds with the Commission's assertion of jurisdiction over unbundled retail transmission services.[523] It maintains that the Commission's arguments do not negate the language of the FPA specifying that regulation of retail sales of electric energy is reserved to the states. MN DPS argues that the Commission's arguments in support of its position are not on point because the issue is state authority to set rates for retail sales, not interstate commerce. Further, it declares that jurisdiction over a service does not change simply because it is priced differently.

Several commenters argue that unbundled pricing should not expand the Commission's jurisdiction.[524] NARUC argues that the NOPR did not explain why the Commission's authority attaches only to unbundled retail transmission service, why unbundling is jurisdictionally significant, and how transmission of electricity to end users differs from unbundled interstate transmission of natural gas by local distribution companies, which is subject to state regulation. Thus, NARUC urges the Commission not to claim jurisdiction over unbundled retail transmission services.

NARUC also argues that the Commission's test for distinguishing between transmission and local distribution is not a bright line as discussed in *Federal Power Commission* v. *Southern California Edison Company,* 376 U.S. 205 (1964) (*Colton*). NARUC concludes that when a state determines to enable a retail customer to purchase power from a third-party provider, that state retains the authority to regulate the delivery service provided by the utility.

IL Com asserts that the test should be whether the utility function over which the Commission seeks to exercise jurisdiction is one which falls within the *Attleboro* gap.[525] It argues that the Commission has no legal authority to prescribe conditions under which a public utility may provide transmission service within its own service territory to its own retail customers. IL Com concedes that the court cases cited by the Commission can be interpreted to support widely disparate legal and policy positions, but argues that those cases resolved questions of Commission jurisdiction in circumstances where wholesale sales of electric power were being examined and not circumstances where retail sales are being considered. It contends that the question of whether the Commission should exercise jurisdiction over all transmission in retail wheeling has never been addressed before and requires a careful examination of the underlying purposes of Congress in enacting the FPA. IL Com explains that transmission by an Illinois utility of power to a retail consumer within its own service territory is not subject to Commission jurisdiction because that transmission was never within the *Attleboro* gap and has always been regulated by states.

OK Com recommends that the Commission apply to the electric industry the same policy that it has adopted concerning its regulation of the gas industry and leave unbundled retail service regulation to state authorities.

WI Com argues that if a utility offers unbundled retail access, jurisdiction over transmission services should continue to be based upon the historical demarcation between wholesale and retail transactions. KY Com argues that Congress did not intend, by authorizing wholesale wheeling in the Energy Policy Act, to change the longstanding division of jurisdiction between the Commission and the states. It claims that the NOPR ignores the limitation in the FPA that the Commission has no jurisdiction over retail sales service. NV Com cites several cases noting the states' historical authority to regulate retail rates.

IA Com proposes a definition of local distribution and transmission that would preserve the jurisdictional status quo and does not put a state commission in the position of losing authority over certain elements of a retail transaction should it allow retail wheeling. IA Com's proposed definition is as follows:

> Distribution—Service provided by a utility directly connected to an ultimate consumer of electricity is a distribution service with respect to electric energy delivered to that consumer.
>
> Transmission—Service provided by a utility with respect to electric energy to be delivered to an ultimate consumer through another utility is a transmission service.[526]

Montana Power states that a reasonable way to give effect to the ''local distribution'' exemption is to define ''local distribution'' as a bundled retail sale, even if interstate facilities are used.

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[523] *See also* OH Com.

[524] *E.g.,* DOD, NM Com, KY Com, ABATE.

[525] *See* Public Utilities Commission v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927).

[526] IA Com Initial Comments at 4.

Several commenters criticized the NOPR's functional/physical indicators. PA Com disagrees with the Commission's discussion of the FPA's legislative history and asserts that the FPA does not address the issue of what constitutes local distribution. PA Com contends that the issue was resolved by the Supreme Court in *CL&P* in a manner contrary to the Commission's technical-functional test and that the NOPR minimized *CL&P*. NM Com asserts that the proposed engineering and functional elements for determining the status of local distribution facilities fail to account for the governmental or legalistic test requirement of the FPA as identified in *CL&P*.

KY Com concludes that a physical definition of distribution facilities, based on objective criteria, is consistent with the FPA and is necessary to provide a clean line of demarcation.

CO Com argues that Congress used a transactional test rather than a functional test and that Congress intended all retail transactions to be under state jurisdiction. According to CO Com, there is concurrent jurisdiction over unbundled transmission in interstate commerce to an end-user. Moreover, CO Com asserts that unbundled intrastate transmission to a wholesale purchaser is under state jurisdiction (citing section 201(b)(1)). Finally, CO Com argues that the state has authority over unbundled transmission in intrastate commerce to an end-user when the transmission-providing utility, end-user, and generator are all within the same state.

Other commenters prefer a functional test. Natural Resources Defense, DOE, and Sustainable Energy Policy generally agree that a line needs to be drawn between transmission and local distribution but believe that the Commission's test is unnecessarily cumbersome or may lead to legal uncertainty, at least within the context of stranded benefits. Instead, Natural Resources Defense proposes the following functional test, which is based on end-use service:

> The Federal Power Act does not affect state regulators' jurisdiction to apply distribution charges—either volume-based or fixed—to electricity that is used by any utility customer to provide end-use services (as distinguished from electricity that is purchased for resale to end-use customers).[527]

Sustainable Energy Policy endorses Natural Resources Defense's position. DOE suggests that a functional definition of local distribution (*i.e.*, electricity provided for end-use service) may be the best way to avoid legal uncertainty.

EPA argues that the Commission's proposed physical definition may encourage gaming to avoid stranded costs and costs associated with public policy goals such as energy efficiency, renewable energy development and R&D funding, and a physical definition assumes that power flows into, and not out of, distribution systems, which would not allow for distributed generation (*e.g.*, fuel cells). Thus, EPA urges the Commission to adopt a functional definition that ''local distribution occurs whenever electricity is provided by a utility for end-use service.'' Alternatively, EPA suggests that the Commission add a provision to its approach that ''the provision of electricity for end-use service generally involves local distribution.'' Sustainable Energy Policy suggests a non-bypassable charge levied on all users of the distribution system. It endorses the policy formulation set forth by Natural Resources Defense in its initial comments. Reynolds wants to ensure that there is always at least concurrent state jurisdiction over lines used to serve end-use customers, since only states can order retail wheeling.

Detroit Edison argues that state/federal jurisdictional issues should be resolved by focusing on the use of the facilities. It says that facilities that are used to distribute a utility's own power to its own local customers should be subject to state regulation, while the use of facilities for wholesale power transactions or wholesale or retail transmission in interstate commerce should be under federal regulation.

Mountain States Petroleum Assoc argues that the Commission should use a functional test based on state boundaries: if a line is in more than one state, there is Commission jurisdiction; if a line is entirely within one state, there is state jurisdiction.

MD Com states that it believes that the Commission's proposed indicators for determining where to draw the line are adequate, but adds that it does not concede the Commission's assertion of jurisdiction over unbundled retail transmission.

Some commenters suggest that implementation of the NOPR's tests could have adverse consequences. NH Com objects to the NOPR's specific tests; for example, if the Commission asserts jurisdiction over facilities because they are not radial, New Hampshire's policy of encouraging looping rather than radial lines would have the ironic effect of destroying state jurisdiction. NJ BPU states that there may be situations when the NOPR factors would not produce the proper result. It requests that the final rule recognize the need for case-by-case flexibility in determining where federal jurisdiction ends, so that the Commission and the states can work cooperatively.

NRRI argues that the NOPR's test could make siting of new transmission lines more difficult because states have in the past required native load customers to pay that part of the transmission-related revenue requirement that is not covered by unbundled transmission service. NRRI contends that, if the Commission asserts jurisdiction over all unbundled transmission service and if there is a firm point-to-point service capacity right that has value and is reassignable, then state commissions might eliminate portions of the transmission systems subject to capacity rights from rate base. NRRI is also concerned that the NOPR's transmission/local distribution test could create a price squeeze between bundled and unbundled retail transmission rates.

IN Com argues that the NOPR's view of jurisdiction would discourage retail wheeling. It says that states will be reluctant to order wheeling if the result is that they lose jurisdiction over the previously rolled-in transmission aspect of the service. It suggests that the Commission use negotiated rulemaking to address jurisdictional issues.

Several commenters suggest alternative approaches to jurisdictional line-drawing. NV Com suggests that the Commission consider federal and state jurisdiction over transmission by using ''network'' and ''non-network'' concepts:

> The ''network'' concept for regulation recognizes that there is an interstate network of electric facilities used to link generation with loads. The operation of that network is indifferent to whether the electrical flows are retail or wholesale flows. Conceptually, events on the network could fall under federal jurisdiction. Where facilities provide essential service for the delivery of power, but do not substantially affect the electrical flows on the network, the facilities fall outside the network and would remain within the traditional domain of the state commission. As a consequence the delineation of federal and state jurisdiction evolves from the recognition of the events and where they occur as opposed to a rigid consideration of the physical properties of the facilities involved.[528]

NV Com further explains that the determination of what is a network event would require a case-by-case examination.

[527] Natural Resources Defense Initial Comments at 3.

[528] NV Com Reply Comments at 3.

OH Com asserts that Congress intends there to be a bright line between state and federal jurisdiction and that the Commission has failed to provide such a bright line. OH Com proposes the use of retail marketing areas to provide the bright line—the jurisdictional line would be at the point at which power enters the retail marketing area of the entity delivering the power to the retail customer. OH Com cites section 212(g) of the FPA, as amended by the Energy Policy Act, which provides that the Commission cannot issue any order under the FPA inconsistent with state law governing retail marketing areas.

Under OH Com's proposal, the Commission would have jurisdiction over the wheeling-out and wheeling-through components of retail wheeling and the state would have jurisdiction over the wheeling-in component due to its local nature. OH Com concludes that the Commission's approach ''fails to meet the legal standard FERC must consider, and is inconsistent with the 'savings clause' and legitimacy of 'retail marketing areas' as discussed in the amended FPA.'' [529] OH Com also explains that the Commission's approach ''is wreaking havoc on the state's ability to develop an interruptible buy-through arrangement to provide an increased competitive option for its retail customers.'' [530] OH Com further encourages the use of mutual deference to promote Congress' intent in mandating a system of federal/state cooperation. In support, OH Com cites federal and state enforcement of telecommunications laws. NRRI also suggests that the jurisdictional line be drawn at the retail marketing area.

DC Com argues that the NOPR test is too difficult to administer and will create problems in determining the rate base at the state level. It suggests that the Commission should have jurisdiction over transmission from the source to the boundary of the ''home'' utility that delivers the power to the customer, with state jurisdiction over all aspects of the transmission service within that utility's franchise territory. AZ Com also expresses doubts that the NOPR's test is workable.

Several commenters propose that the Commission and state authorities address the jurisdictional issue jointly. SBA characterizes the Commission's proposed demarcation line as ''laudable but misguided.'' [531] SBA recommends that a federal/state board be established to resolve the transmission/local distribution dilemma, similar to what Congress did for allocating costs between interstate and intrastate communications. SBA explains that the problem in the communications industry was the impossibility of allocating a portion of a single copper wire to interstate or intrastate service.

AZ Com notes that even if the Commission is correct, the FPA clearly does not preempt a state from concluding that retail transmission or other direct access programs should be implemented in that state. AZ Com suggests that there may be concurrent jurisdiction and that mutually agreed-upon principles should be implemented to determine which jurisdiction should be given deference.

MD Com states that in determining the status of particular facilities, the Commission should give substantial weight to determinations made by states. ABATE states that the Commission could initially defer to states with respect to the determination of rates, terms, and conditions, while maintaining the right to review and overturn the state determination.

If the Commission maintains its position concerning jurisdiction, NARUC argues that the Commission should not implement its multi-factor test, but should enter into discussions with state commissions to develop workable alternatives. NH Com argues that pricing the retail part of a transaction, even if it involves use of the transmission system, should be subject only to state jurisdiction. NH Com wants to create a mechanism by which state and federal regulators combine their efforts in cooperative regulation; it suggests several alternatives such as state/federal agreements for shared jurisdiction.

KY Com and NRRI object to the statement in the NOPR that retail buy-through service is really transmission service (subject to the Commission's jurisdiction) plus a sale of generation at retail (subject to state jurisdiction). From a policy standpoint, KY Com argues that the Commission's approach creates a powerful disincentive for a state to embark on changes that otherwise might foster a more competitive environment. NRRI argues that the Commission's approach may violate sections 212(g) and 212(h).

IL Com is concerned that industrial customers who get direct access may attempt to evade state jurisdiction, and thus avoid retail stranded cost charges, by bypassing facilities such as radial lines. It contends that retail wheeling rate surcharges would be a more effective means of recovering retail stranded costs if states were allowed to apply them to unbundled transmission and local distribution rates, not just the local distribution component of such rates.

NC Com asserts that ''[a] significant cottage industry may well arise solely to convert retail customers into wholesale customers, thereby subverting the intent of Congress as expressly set forth in EPACT.'' [532] If the Commission does not adopt NARUC's proposal, NARUC asserts that the Commission's functional test should not permit an end user to bypass the distribution service provided by the utility. It urges the Commission to assure that there will be some facility involved in the transaction that will be defined as providing a local distribution service.

NARUC also requests that the following sentence be added to proposed 18 CFR 35.27:

> Nothing in this part limits the authority of a State commission in accordance with State law (1) to allow or disallow the inclusion of the costs of electric energy purchased at wholesale in retail rates subject to such State commission's jurisdiction, (2) to establish competitive procedures for the acquisition of such electric energy, or (3) to establish non-discriminatory fees for the delivery of such electric energy to retail consumers for purposes established in accordance with State law.([533])

Duke is concerned about the potential for regulatory gaps, which could lead to costs not being recovered from either federal or state jurisdiction. Duke is also concerned that where facilities are used for both wholesale and retail transactions, costs might not be recovered if federal and state regulators use different methods of cost allocation.

In response to the NOPR's proposal for functional unbundling,[534] CA Com agrees that it is important to draw a distinction between transmission and local distribution and that a bright line is not possible, but suggests that corporate or functional unbundling

[529] Sections 212(g) and 212(h) of the FPA.

[530] We note that since OH Com filed its comments, it approved an interruptible buy-through plan. *See* Interruptible Electric Service Guidelines, Case No. 95–866–EL–UNC, __ PUR 4th __ (Ohio PUC Feb. 15, 1996). *See also* Central Illinois Light Company, Docket No. ER96–1075–000, 75 FERC ¶ ______ (1996) (accepting amendment to open access transmission tariffs that expands service eligibility to accommodate participation in experimental retail wheeling pilot program approved by the Illinois Commerce Commission); Illinois Power Company, Docket No. ER96–1285–000, 75 FERC ¶ ______ (1996); *cf.* Illinois Power Company, __ PUR4th __, No. 95–0494 (Illinois Commerce Commission Mar. 13, 1996) (offering retail direct access service providing transmission and ancillary services using the rates, terms, and conditions of Illinois Power's open access tariff on file with the Commission); recently introduced legislation in Rhode Island, H.B. 8124, the Utility Restructuring Act of 1996.

[531] SBA Initial Comments at 36.

[532] NC Com Initial Comments at 7.

[533] NARUC Reply Comments at 15–16.

[534] FERC Stats. & Regs. ¶ 32,514 at 33,080–83.

might provide a means to establish a workable bright line without relying on the more qualitative approach proposed in the NOPR. Arizona argues that rather than unbundling transmission for retail purposes, each utility should establish a distribution function that would obtain transmission on behalf of retail customers, taking service under the utility's tariff. Arizona states that this would simplify the allocation of transmission costs, since all transmission costs would be under the Commission's jurisdiction. Arizona argues that the Commission should permit the utility to recover the distribution rate approved by the state. According to Arizona, this would create a bright line between state and federal jurisdiction.

TX Com argues that the proposed test would not be applicable to intrastate utilities in Texas because they do not operate in interstate commerce. Thus, it asserts that it should continue to regulate Electric Reliability Council of Texas (ERCOT) transmission and distribution service and deal with stranded cost issues that arise in connection with any retail wheeling initiatives.

Several commenters object to the Commission's proposal to assert jurisdiction over transactions that are buy-sell transactions in name only.[535] AEP argues that the Commission should avoid an unnecessary conflict over state/federal jurisdiction that may be caused by the NOPR's statement that buy-sell transactions are in fact transmission subject to Commission jurisdiction. It suggests that the Commission attempt to reach agreement with the states on this matter or ask Congress for any necessary statutory change. Citizens Utilities also argues that the Commission should not unbundle the interstate transmission aspect of buy-sell transactions. It says that, unlike the analogous gas contracts, buy-sell arrangements on the electric side are not an end run around clear federal jurisdiction. Further, it argues that it would be very difficult to define those buy-sell transactions that truly belong under federal jurisdiction.

IL Com also objects to the NOPR's characterization of buy-sell transactions. It argues that the fact that a transaction becomes unbundled does not suddenly make part of it under federal jurisdiction. Nucor argues that there is no need for the Commission to resolve this issue now; it suggests that the buy-sell arrangement is only tangentially related to open access. It argues that each buy-sell transaction will have to be addressed individually.

UT Com seeks clarification as to what the Commission means by buy-sell arrangements:

> we currently authorize interruptible ''buy-through'' contracts, through which a retail customer, taking service subject to interruption for either economic or technical reasons, can opt to ''buy-through'' an interruption. The public utility purchases energy on behalf of the customer and sells it at cost to the customer. In our opinion, such transactions are not an example of a buy-sell transaction within the meaning of the proposed rule.[536]

DOD objects to the statement in the NOPR that ''buy-sell'' transactions are not really bundled retail service. It says that this view will discourage the development of innovative state programs, such as direct access programs. NYSEG also argues that buy-sell transactions are not under the Commission's jurisdiction. It argues that these transactions are unlike buy-sell transactions on the gas side, where the Commission asserted jurisdiction to prevent LDCs from circumventing the nondiscrimination standard it imposed on the release of capacity. NYSEG says:

> In contrast to its regulation of gas buy-sells, if the Commission regulates electric buy-sell transactions it would forego regulation of a transaction in which the Commission has a significant interest (*i.e.*, access to the upstream seller's transmission), to regulate a transaction in which the Commission has virtually no interest (*i.e.*, access to the distributing utility's system). Electric utilities must serve each retail customer irrespective of whether the customer takes traditional bundled service or retail buy-sell service. Unlike excess upstream gas pipeline capacity, the capacity on the local utility's electric system would not be allocated to another customer in a FERC jurisdictional transaction absent the electric buy-sell transaction. Electric buy-sell transactions are not designed so as to manipulate the assignment of upstream transmission capacity. Consequently, the impetus for FERC to reclassify gas buy-sell transactions as capacity assignments is not present in the electric context.[537]

NYSEG argues that there are only two possible grounds for the Commission's assertion of jurisdiction over electric buy-sell transactions: either (1) the sale for resale by the supplier is really a sale at retail to the end user, and the resale by the local utility is really unbundled retail wheeling; or (2) the Commission has jurisdiction over transmission service that is part of bundled retail service. It claims that the second ground is invalid because the transmission aspect of bundled retail service is distribution. It also claims that the first ground is invalid because it assumes that the sale by the supplier to the local utility is not a sale for resale even though the contract says that it is. NYSEG states:

> The logical outcome would be that FERC would *not* have jurisdiction over the sale by the supplier to the utility, including transmission by that supplier because it would be a bundled retail sale. This is because, if the commission holds the resale to be a retail wheel, then it would have to find that the sale by the supplier is a retail sale to the end user. The Commission cannot at once regulate the sale for resale and the ''retail transmission service.'' The Commission would regulate the transmission rates of the local franchise utility, although it would not regulate the access to such transmission service—a matter FERC leaves to state regulators. In the process, FERC would abandon the ability to regulate access to the supplier's bundled ''retail power sale and transmission service,'' a transaction that FERC arguably has an interest in regulating.[538]

Finally, NYSEG argues that if the Commission insists on asserting jurisdiction, it should at least grandfather existing contracts.

UT Industrials state that where there is a state barrier to a buy-sell transaction, the Commission should allow the utility to file a tariff with the Commission that would permit the utility to complete a voluntary buy-sell transaction as the NOPR proposes. However, it contends that when a state regulatory authority is authorized to, and has approved buy-sell transactions, it is not necessary for the Commission to become involved. It urges the Commission to allow such transactions to take place free of Commission regulation.

Commission Conclusion

In the discussion below, the Commission addresses the following jurisdictional issues raised in the prior NOPRs:

a. Does the Commission have jurisdiction over unbundled transmission in interstate commerce by a public utility when such transmission is used to transport electric energy that is sold to an end user?

b. If so, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to an end user?

c. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

[535] *See id.* at 33,082.

[536] UT Com Initial Comments at 4–5.

[537] NYSEG Initial Comments at 48 (footnote omitted).

[538] NYSEG Initial Comments at 50.

d. What procedures are appropriate for making jurisdictional determinations?

In addition, the Commission addresses concerns raised by state regulators which indicate that competition and open access are perceived as threatening the traditional regulatory functions of state commissions. The Federal Power Act differentiates between state and federal regulation of electric power. As we discuss below, the Commission believes that any change in state or federal jurisdiction over physical transmission assets and related costs will not affect the traditional tasks of state and federal regulators.

The wide range of jurisdictional interpretations and proposals in the comments reflects the fact that the legislative history of the FPA and case law interpreting federal/state jurisdiction under that Act and the Natural Gas Act grew out of a market structure in which electricity and transmission generally were bought and sold on a bundled basis. As a result, most transactions included either a retail or wholesale sale of electric energy and jurisdictional lines were drawn on the basis of this sale. Thus, the cases simply do not resolve dispositively these jurisdictional issues when they arise in the context of the market structures and unbundled transactions being contemplated in today's electric industry. However, after reviewing the extensive analysis of the FPA, legislative history, and case law contained in both our initial Stranded Cost NOPR and in our Open Access NOPR, and the comments received on that analysis, we continue to believe that we were correct in asserting jurisdiction over the transmission component of an unbundled interstate retail wheeling transaction. We therefore reaffirm our conclusion. We also reaffirm and clarify our determinations regarding the tests to be used to determine what constitute Commission-jurisdictional transmission facilities and what constitute state-jurisdictional local distribution facilities in situations involving unbundled wholesale wheeling and unbundled retail wheeling.[539]

At the same time, the Commission strongly supports the efforts of states to pursue pro-competitive policies. We recognize that jurisdictional issues raise overlapping Federal and state policy concerns that call for heightened cooperation among federal and state regulators. As discussed below, where states unbundle retail sales, we will give deference to their determinations as to which facilities are transmission and which are local distribution, provided that the states, in making such determinations, apply the seven criteria discussed in the NOPR and reaffirmed below. In addition, we clarify our view that there is an element of local distribution service in any unbundled retail transaction, and further clarify other aspects of our jurisdictional ruling to preserve state jurisdiction over matters that are of local concern and will remain subject to state jurisdiction if retail unbundling occurs.

We first address our legal determination that if unbundled retail transmission in interstate commerce occurs voluntarily by a public utility or as a result of a state retail access program, this Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission. No commenter has raised cases or legislative history not previously considered in our prior NOPRs, and we will not repeat here our full legal analysis of this issue.[540] However, we find compelling the fact that section 201 of the FPA, *on its face,* gives the Commission jurisdiction over transmission in interstate commerce (by public utilities) without qualification.[541] Unlike our jurisdiction over sales of electric energy, which section 201 of the FPA specifically limits to sales at wholesale, the statute does not limit our transmission jurisdiction over public utilities to wholesale transmission.

In response to those commenters (including NARUC) who argue that the Commission did not explain why its authority attaches only to unbundled, but not bundled, retail transmission in interstate commerce by public utilities, we believe that when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves *only* the provision of ''transmission in interstate commerce'' which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal sphere of regulation.

In asserting jurisdiction over unbundled retail transmission in interstate commerce by public utilities, the Commission in no way is asserting jurisdiction to order retail transmission directly to an ultimate consumer. Section 212(h) of the FPA clearly prohibits us from doing so. In addition, as stated in both the initial Stranded Cost NOPR and the Open Access NOPR, we do not address whether states have authority to order retail wheeling in interstate commerce. The Commission's assertion of jurisdiction is that *if* retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail wheeling program, the Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission and public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.

The Commission clarifies that nothing in this jurisdictional determination changes historical state franchise areas or interferes with state laws governing retail marketing areas of electric utilities. Section 212(g) of the FPA prohibits Commission orders that would be inconsistent with such laws. However, we reject arguments made by some of the commenters that section 212(g) could somehow be construed to give states authority over the rates, terms, and conditions of unbundled interstate transmission within retail marketing areas.[542] While our

[539] Not only do we conclude that our determinations are legally supportable under the case law, but we believe it is imperative to provide guidance to public utilities and state regulators as to our position on where the jurisdictional boundaries lie.

[540] The Commission's complete legal analysis on this issue, and on the related issue of what facilities are Commission-jurisdictional transmission facilities, and what are state jurisdictional local distribution facilities, are contained in Appendix G to this Rule.

[541] Section 201(b)(1) specifically exempts from Commission jurisdiction facilities used for transmission in intrastate commerce and transmission of electric energy consumed wholly by the transmitter. As a result, we have no jurisdiction over retail wheeling that occurs in Alaska, Hawaii and the Electric Reliability Council (ERCOT) portion of Texas since transactions in those areas are intrastate.

[542] The legislative history of FPA section 212(g) and its predecessor, former section 211(c)(3), indicates that the provision was focused on not interfering with state laws governing retail service territories and not permitting Commission wheeling orders ''for purposes of sale by a utility to an ultimate consumer who is within the service territory of another utility (other than the applicant) where such territory is established by or under State law, rule, or decision.'' *See* H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. 92 (1978), *reprinted in*

Continued

jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusivejurisdiction over transmission in interstate commerce by public utilities.

In response to several of the commenters, we further clarify that the Commission's jurisdiction over the rates, terms, and conditions of unbundled retail transmission is no broader than our authority over transmission used for wholesale transactions, and will not affect matters otherwise left to the states by Congress.[543] The Federal Power Act recognizes that retail marketing areas are governed by state law. Moreover, we believe that states have authority over the *service* of delivering electric energy to end users. In exercising this authority, state regulatory commissions and state legislatures have traditionally developed social and environmental programs suited to the circumstances of their states. State regulation of most power production and virtually all distribution and consumption of electric energy is clearly distinguishable from this Commission's responsibility to ensure open and non-discriminatory interstate transmission service. Nothing adopted by the Commission today, including its interpretation of its authority over retail transmission or how the separate distribution and transmission functions and assets are discerned when retail service is unbundled, is inconsistent with traditional state regulatory authority in this area.

The Commission reiterates its strong interest in preventing any balkanization of the interstate power market. Although the Commission believes its Final Rule will accommodate retail competition, if it is offered voluntarily by a utility or ordered by a state, our policies relate only to the bulk power market and not traditional state regulation of the retail market.[544]

NARUC has requested that the Commission specifically clarify in § 35.27 of its proposed rules[545] that nothing in our final rule limits the authority of a state commission ''to allow or disallow the inclusion of the costs of electric energy purchased at wholesale in retail rates subject to such State commission jurisdiction.'' We will adopt NARUC's proposal with modification, but add it as a separate subsection. The Final Rule adopts a new § 35.27(b) as follows:

> Nothing in this part (i) shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or (ii) limits the authority of a state commission in accordance with state and federal law to establish (a) competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or (b) non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

With respect to the Commission's adoption of the Open Access NOPR's functional/technical tests for determining what facilities are Commission-jurisdictional facilities used for transmission in interstate commerce and what facilities are state-jurisdictional local distribution facilities, the case law supports a bright line for unbundled wholesale transmission, *i.e.*, transmission of electric energy that is being sold for resale. This is consistent with the bright line drawn by Congress to fill the *Attleboro* gap for regulating wholesale sales of electric energy. The case law also supports a bright line with respect to retail transmission by intervening utilities, *i.e.*, transmission by those utilities between the new retail generation supplier and the public utility that previously provided bundled retail service to the end user. However, despite many commenters' arguments to the contrary, we cannot divine such a bright line for unbundled retail transmission by the public utility that previously provided bundled retail service to the end user. In fact, the limited case law, including *CL&P* and *Colton*, supports a case-by-case determination.[546] Accordingly, we believe our technical test, with its seven indicators, will permit reasoned factual determinations in individual cases.

Although we are unable to draw the bright line for local distribution facilities that many commenters would like, we believe it is important to make two clarifications regarding local distribution in the context of retail wheeling. First, even when our technical test for local distribution facilities identifies no local distribution facilities for a specific transaction, we believe that states have authority over the *service* of delivering electric energy to end users. Second, through their jurisdiction over retail delivery services, states have authority not only to assess stranded costs but also to assess charges for stranded benefits, such as low-income assistance and demand-side management. Because their authority is over services, not just the facilities, states can assign stranded costs and benefits based on usage (kWh), demand (kW), or any combination or method they find appropriate. They do not have to assign them to specific facilities.[547]

Thus, while we believe in most cases there will be identifiable local distribution facilities subject to state jurisdiction, we also believe that even where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users. Under this interpretation of state/federal jurisdiction, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to bypass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits.

Based on concerns raised by state commissions as well as some utilities, we have further determined that it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs. We also believe it is important to develop mechanisms to avoid regulatory conflict and to help provide certainty to utilities as to which regulator has jurisdiction over which facilities. These are discussed below.

1978 *U.S. Code Cong. & Ad. News* 7797, 7826. Nothing on the face of section 212(g) or the legislative history of either the Energy Policy Act or PURPA indicates that the provision in any way affects the Commission's authority over rates, terms, and conditions of transmission in interstate commerce by public utilities.

[543] Among other things, Congress left to the States authority to regulate generation and transmission siting. *See* FPA sections 201(b) and 211(d)(1); section 731 of the Energy Policy Act.

[544] This Final Rule will not affect or encroach upon state authority in such traditional areas as the authority over local service issues, including reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, including DSM; authority over utility generation and resource portfolios; and authority to impose non-bypassable distribution or retail stranded cost charges.

[545] Section 35.27 of the proposed rules provided that any public utility seeking authorization to engage in sales for resale at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity first placed in service on or after 30 days from the date of publication of the Final Rule in the Federal Register. FERC Stats. & Regs. ¶ 32,514 at 33,154.

[546] As noted, the Commission's detailed legal analysis is contained in Appendix G. We are particularly persuaded by the Supreme Court's statement that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. *See* CL&P, 515 U.S. at 534–35.

[547] As noted above, states retain authority over state integrated resource planning, utility resource portfolios, and utility buy-side and demand-side decisions.

Determining where to draw the jurisdictional line for facilities used in unbundled retail wheeling transactions will involve case-specific determinations that evaluate the seven local distribution indicators that we are adopting. We believe that the Commission should take advantage of state regulatory authorities' knowledge and expertise concerning the facilities of the utilities that they regulate. Therefore, in instances of unbundled retail wheeling that occurs as a result of a state retail access program, we will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the Commission's technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule.[548] Moreover, we recognize that in some cases the Commission's seven technical factors may not be fully dispositive and that states may find other technical factors that may be relevant. We will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities.

Some commenters have asked the Commission to provide a forum to prevent or resolve disputes over the correct classification of facilities as transmission or local distribution. As a means of facilitating jurisdictional line-drawing, we will entertain proposals by public utilities, filed under section 205 of the FPA, containing classifications and/or cost allocations for transmission and local distribution facilities. However, as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission, utilities must consult with their state regulatory authorities. If the utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission will defer to such classifications and/or cost allocations.[549] We encourage public utilities and their state regulatory authorities to attempt to agree to utility-specific classifications and allocations that the utility may file at the Commission.

A number of commenters have asked the Commission to defer to state commission recommendations or decisions regarding rates, terms and conditions of unbundled retail transmission in interstate commerce by public utilities. Some have suggested that we set broad guidelines for such rates, terms, and conditions, and then allow states to actually implement the guidelines. While the Commission cannot simply turn over its jurisdiction for the states to implement, we understand the concerns raised by many state regulators and believe that deference to state commissions with regard to rates, terms, and conditions may be appropriate in some circumstances, as discussed below.

As we determined in the NOPR, when unbundled retail wheeling in interstate commerce occurs, the transaction has two components for jurisdictional purposes—a transmission component and a local distribution component. The Commission has jurisdiction over facilities used for the transmission component of the transaction, and the state has jurisdiction over facilities used for the local distribution component.[550] Thus, the rates, terms and conditions of unbundled retail transmission by a public utility must be filed at the Commission. When this occurs, we will generally expect unbundled retail wheeling customers to take service under the same FERC tariff that applies to wholesale customers. However, if the unbundled retail wheeling occurs as part of a state retail access program, it may be appropriate to have a separate retail transmission tariff[551] to accommodate the design and special needs of such programs. In such situations, the Commission will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles reflected in the tariff prescribed by this Final Rule. In addition, rates must be consistent with our Transmission Pricing Policy Statement, and the guidance herein concerning ancillary services.[552]

A final jurisdictional issue raised in the Open Access NOPR concerns buy-sell transactions. We remain concerned, just as we were with buy-sell arrangements in the gas industry, that buy-sell arrangements can be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. Thus, we reaffirm our conclusion that we have jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third-party. However, we recognize that there is a wide range of programs and transactions that might or might not fall within this category. We will address these on a case-by-case basis.

In summary, the Commission reaffirms and clarifies its prior jurisdictional conclusions and tests for determining the demarcation between federal and state jurisdiction over transmission in interstate commerce and local distribution. We have attempted to address these issues in a way that provides for flexibility and recognition of legitimate state concerns. With regard to retail services, we recognize the states' concerns that the unbundling of retail transactions would result in changes from what historically has been regulated by the states (principally, the rates of transmission assets previously included in retail rate base). However, the decision to provide unbundled retail wheeling is not the Commission's to make because we have no authority to order transmission directly to an ultimate consumer. In addition, even if a retail access program occurs, we do not believe the unbundling of retail transactions will radically change fundamental state authorities, including authority to regulate the vast majority of generation asset costs, the siting and maintenance of generation facilities and transmission lines, and decisions regarding retail service territories. Further, the Commission intends to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies. As the electric industry and state regulatory authorities continue to develop new competitive market structures and consider retail wheeling programs, we believe that the tests and mechanisms we have provided in this Rule will accommodate both Federal and state interests and will help provide jurisdictional certainty to market participants.

[548] In order to give such deference, we expect state regulators to specifically evaluate the seven indicators and any other relevant facts and to make recommendations consistent with the essential elements of the Rule.

[549] This should also alleviate some concerns about the potential for costs not being accounted for if the Commission and a state commission use different methods of allocating costs.

[550] As discussed above, even if there were instances where no local distribution *facilities* are used, we believe states have authority over the *service* of delivering electric energy to end users.

[551] *I.e.*, the tariff would be different from the tariff that applies to wholesale customers. Such tariff would still be filed with the Commission under FPA section 205.

[552] In applying the principles of the Final Rule to retail transmission tariffs, the Commission clearly cannot order retail wheeling directly to an ultimate consumer. *See* FPA section 212(h).

J. Stranded Costs

1. Justification for Allowing Recovery of Stranded Costs

In the Supplemental Stranded Cost NOPR, the Commission noted that the Open Access Rule would give a utility's historical wholesale customers greatly enhanced opportunities to reach new suppliers.[553] This would affect the way in which utilities have recovered costs under the traditional regulatory system that, on the one hand, imposed an obligation to serve,[554] and, on the other hand, permitted recovery of all prudently incurred costs. We noted that if customers leave their utilities' generation systems without paying a share of these costs, the costs will become stranded unless they can be recovered from other customers. The Commission stated in the NOPR that we must address the costs of the transition to a competitive industry by allowing utilities to recover their legitimate, prudent and verifiable stranded costs simultaneously with any final rule we adopt requiring open access transmission.[555]

Comments

Virtually all of the investor-owned utility commenters as well as commenters representing state commissions and other constituencies support the NOPR's premise that stranded costs can be created when a customer switches suppliers. They endorse the proposal to allow the recovery of legitimate and verifiable stranded costs.[556] Numerous commenters also support the Commission's proposal to link stranded cost recovery with open access tariffs. These commenters agree that the recovery of stranded costs is critical to the successful transition of the industry to an open transmission access, competitive industry.[557] Commenters such as EEI and NU submit that open access and stranded cost recovery should be implemented simultaneously; that unbundled transmission service should not be required until a stranded cost recovery mechanism is in place. Some commenters propose that if the full recovery of stranded costs is disallowed as a result of rehearing or judicial review, utilities that have filed open access transmission tariffs should be permitted to withdraw them, or the Commission should otherwise reconsider its rule on open access transmission in light of such a reversal.[558]

Commenters representing the financial community reiterate their strong support for the full recovery of stranded costs, noting that the prospect of not recovering stranded costs could erode a utility's ability to attract capital which, in turn, could impede the long-term goal of achieving competitive wholesale markets.[559] Several commenters also argue that stranded cost recovery is economically efficient and is necessary to ensure parity among competitors and to avoid uneconomic bypass.[560]

The commenters that oppose allowing utilities to recover legitimate and verifiable stranded costs repeat many of the arguments that were raised in response to the initial Stranded Cost NOPR. For example, a number of commenters argue that the risk that a utility could lose customers (and thereby incur stranded costs) is not a new phenomenon created by regulatory and statutory initiatives that utilities could not have anticipated.[561] Some commenters argue that there was never an implied obligation to serve at wholesale.[562] According to TDU Systems, monopoly power, not regulatory obligation, has kept wholesale customers captive over the years.

Other commenters argue that allowing the recovery of stranded costs would make it uneconomic for customers to seek alternative sources of power and that the prospect of liability for and protracted litigation over stranded cost claims would create paralyzing uncertainty for customers, uncertainty that may dissuade them from taking advantage of new opportunities in the wholesale power market.[563] Some commenters also argue that stranded cost recovery would be a disincentive to efficient operation by affording the greatest protection to utilities that made the worst investment decisions.[564]

Commenters also argue that the scope of the proposed rule is overbroad; that stranded cost recovery should be allowed, if at all, on a case-by-case basis; that there should be no presumption that every utility will experience stranded costs; and that utilities should not be allowed to recover 100 percent of prudently incurred stranded costs.[565]

Several commenters suggest that there is no factual basis for the stranded cost rule, citing a lack of evidence of a wholesale stranded cost problem.[566] TDU Systems refers to a Resource Data International study that shows that, of $114 billion in potential investor-owned utility stranded investment, only $10.4 billion is associated with wholesale transactions.[567] Others submit that the

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553 FERC Stats. & Regs. ¶ 32,514 at 33,095.

554 The Supplemental Stranded Cost NOPR described such an obligation as explicit at retail and arguably implicit at wholesale. FERC Stats. & Regs. ¶ 32,514 at 33,101.

555 *Id.* at 33,095–96, 33,101.

556 *See, e.g.,* EEI, Atlantic City, Arizona, Carolina P&L, Centerior, Central Hudson, Detroit Edison, Duke, Duquesne, Entergy, Florida Power Corp, El Paso, Houston, NIPSCO, NU, Oklahoma G&E, Otter Tail, PG&E, Puget, Southern, San Diego G&E, SCE&G, SoCal Edison, Montana, Montana-Dakota Utilities, NSP, Utilities For Improved Transition, NC Com, PA Com, Electric Consumers Alliance, American National Power, NE Public Power District, MEAG, OH Coops, Seattle, NY Energy Buyers, SBA, TVA, Utility Workers Union, Big Rivers EC, Central EC, Citizens Lehman, NGSA, AGA, Montaup, NIEP.

557 *See, e.g.,* EEI, Coalition for Economic Competition, EGA, CINergy, Electric Consumers Alliance, Atlantic City, Com Ed, Consumers Power, Dayton P&L, Dominion, Duke, El Paso, NEPCO, NIMO, NIPSCO, Ohio Edison, Florida Power Corp, PECO, Pennsylvania P&L, PSNM, Public Service Co of CO, Southern, SCE&G, VEPCO, Texas Utilities, DOE, CA Energy Com, CO Com, PA Com, NE Public Power District, SMUD, Brazos, Sunflower, PJM, Utility Workers Union, Utility Investors Analysts, Nuclear Energy Institute, SoCal Gas, AGA, Utility Shareholders, LPPC. Although DOD agrees that addressing stranded costs is a critical part of the transition to a more competitive industry, it submits that there is nothing in the Open Access NOPR that should affect the treatment of stranded costs because the Open Access NOPR would not change the contracts that govern existing wholesale transactions. It argues that the Commission will have ample opportunity to decide these matters before the present wholesale long-term contracts expire.

558 *E.g.,* Utilities For Improved Transition, PECO, Utility Workers Union, Dayton P&L.

559 Utility Investors Analysts, Utility Shareholders.

560 *See, e.g.,* EEI, SCE&G, Montana, Com Ed.

561 *E.g.,* TAPS, IN Industrials, Air Liquide, Texas Industrials, Detroit Edison Customers, AMP-Ohio.

562 *E.g.,* TDU Systems, Competitive Enterprise.

563 *See, e.g.,* Missouri Joint Commission, Omaha PPD, American Forest & Paper, TAPS, AMP-Ohio, Kansas Commission, VA Com, Nucor, Torco, IPALCO, DE Muni, Municipal Energy Agency Nebraska, Air Liquide, Arkansas Cities, Detroit Edison Customers, Cleveland, Texas-New Mexico, Blue Ridge, Suffolk County, NM Industrials, PA Munis, Caparo, ABATE, NRRI, Building Owners, Alma, WEPCO, Total Petroleum. SC Public Service Authority asserts that the Commission has not adequately addressed the anticompetitive potential of exit fees and the potential shifting of losses from high-cost to low-cost producers. It says that the Commission should renotice any further proposal that it develops to permit a reasoned analysis of anticompetitive concerns.

564 *E.g.,* TAPS, AMP-Ohio, IPALCO, Suffolk County, Competitive Enterprise, NY Energy Buyers, Supervised Housing, Central Illinois Light, WP&L, SC Public Service Authority, KS Com.

565 *E.g.,* Alma, IPALCO, Suffolk County, CO Consumers Counsel, Arkansas Cities, Central Illinois Light, NY AG, NASUCA, VA Com, NY Energy Buyers, UT Industrials, NM Industrials, NJ Ratepayer Advocate, WEPCO, IN Industrials, ABATE, AZ Com.

566 *E.g.,* ELCON, TDU Systems, Texas-New Mexico, Central Illinois Light.

567 However, Utilities for Improved Transition refers to a report by Moody's Investor Service estimating that the stranded costs of the Nation's 114 largest electric utilities under open access transmission will be $135 billion in the next ten years (13 to 14 times greater than the costs stranded by the introduction of open access transportation of

Commission should obtain more current data concerning the magnitude of potential stranded cost recovery before issuing the final rule.[568] In reference to the statement in the Supplemental NOPR that the Commission will continue to gather information on the magnitude of potential stranded costs,[569] DE Muni states that the Commission must commit to making public all the data it obtains so that all can evaluate the impact of the recovery of stranded costs on an ongoing basis.

NRRI submits that the Commission has drawn the wrong conclusion from its natural gas industry experience. According to NRRI, pipelines were ''caught in an unusual transition'' by changes caused by Congress and the Commission. In the case of the electric industry, NRRI submits that although there are uneconomic wholesale power contracts, the Commission is not responsible for this situation.[570]

Several commenters suggest that the Commission condition a utility's ability to recover stranded costs upon the utility agreeing to take certain actions (such as reducing environmental effects [571] or ensuring the payment of costs that are stranded if the utility commences direct service to an end-use customer that was previously a wholesale customer of a transmission dependent utility [572]), or agreeing to refrain from certain actions (such as seeking unilaterally to terminate or modify IPP contracts).[573] CCEM proposes that open access, conversion rights, and divestiture should each be a precondition to a utility's eligibility for any stranded cost recovery. VT DPS submits that, if the Commission adopts a stranded cost rule, it should limit utility stranded cost claims to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the final rule.[574]

A number of commenters object that the proposed rule contains no provisions for non-transmission-owning utilities to collect stranded costs.[575] Illinois Municipal Electric Agency asks the Commission to consider providing a forum for municipals to recover stranded costs from their customers under the same guidelines as investor-owned utilities. Recognizing that the FPA gives the Commission no general jurisdiction over municipalities for purposes of rate regulation,[576] Illinois Municipal Electric Agency argues that the FPA nevertheless does not prevent the Commission from providing a forum for municipalities that may experience stranded costs as a result of new federal regulations. NE Public Power District, RUS, and rural electric cooperative commenters object that the NOPR gives public utilities a greater chance than other transmitting utilities to recover stranded costs from departing customers by offering public utilities two avenues of recovery (an exit fee under a power sales contract or a transmission surcharge) but offering other transmitting utilities only one avenue (a transmission surcharge).[577]

PA Munis objects that the Commission's proposal to impose stranded costs only on wholesale requirements customers (and not on other wholesale customers) is unduly discriminatory and counter to the goals of the Open Access NOPR. It submits that the Commission's proposal, by subjecting a wholesale requirements customer to increased transmission rates for stranded costs not levied on other wholesale customers, is indistinguishable in substance from the pre-Order 436 plan held to be discriminatory in *Maryland People's Counsel* v. *FERC*.[578]

ELCON and others [579] urge the Commission to clarify that stranded costs do not arise when a customer leaves a system because its plant becomes uneconomic or the customer wishes to co-generate or self-generate. They note that ''[t]hese alternatives have always existed and do not arise from new opportunities for wholesale and retail wheeling.'' [580]

Commission Conclusion

We reaffirm our preliminary determination that the recovery of legitimate, prudent and verifiable stranded costs should be allowed. Having considered the arguments raised by the commenters that oppose stranded cost recovery, we continue to believe that utilities that entered into contracts to make wholesale requirements sales under an entirely different regulatory regime should have an opportunity to recover stranded costs that occur as a result of customers leaving the utilities' generation systems through Commission-jurisdictional open access tariffs or FPA section 211 orders,[581] in order to reach other power suppliers. As we indicated in the Supplemental Stranded Cost NOPR, we do not believe that utilities that made large capital expenditures or long-term contractual commitments to buy power years ago should now be held responsible for failing to foresee the actions this Commission would take to alter the use of their transmission systems in response to the fundamental changes that are taking place in the industry.[582] We will not ignore the effects of recent significant statutory and regulatory changes on the past investment decisions of utilities.[583] While, as some commenters point out, there has always been some risk that a utility would lose a particular customer, in the past that risk was smaller. It was not unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet future customer needs. With the new open access, the risk of losing a

natural gas). It notes that this estimate covers costs stranded by transmission in interstate commerce of both wholesale and retail power, and submits that both types of costs are relevant to this proceeding because of the Commission's jurisdiction over the transmission rates for wheeling to both wholesale and retail customers.

[568] *E.g.*, Central Illinois Light, Utility Workers Union, Alcoa.

[569] *See* FERC Stats. & Regs. ¶ 32,514 at 33,105.

[570] According to NRRI, the Commission did not ''berate'' electric utility management to sign uneconomic contracts in the manner that NRRI contends the Commission and Congress ''berated'' pipeline management. NRRI Initial Comments at 6. NRRI also objects that the proposed rule is a departure from what occurred in other deregulated industries (where no stranded cost recovery was allowed) and that the Commission should provide a fuller explanation as to why it believes allowing utilities full recovery of legitimate and verifiable stranded costs is the correct course of action.

[571] *E.g.*, Legal Environmental Assistance, Conservation Law Foundation.

[572] *E.g.*, TDU Systems.

[573] *E.g.*, EGA, LG&E. EGA and LG&E further argue that if a utility is able to abrogate a QF contract, a QF should be entitled to recover its costs based upon the same equities of reliance upon governmental approvals, changed regulatory regimes, and reasonable expectation.

[574] VT DPS argues that under Order No. 636, the Commission allowed recovery of costs that would be rendered ''unrecoverable'' because the costs would not be incurred to provide transportation service and because there would be no wholesale load from which to recover the costs. It suggests that when a utility loses wholesale load or a municipality establishes a new distribution system, the utility's costs are not necessarily rendered unrecoverable.

[575] *E.g.*, PA Munis, Missouri Joint Commission, TAPS, Municipal Energy Agency Nebraska.

[576] *But see* FPA section 212(a), 16 U.S.C. 824k(a).

[577] RUS objects that, at the same time, an RUS-financed cooperative that is a transmitting utility would be required to provide reciprocal open access to its public utility supplier, which is also its customer and its competitor.

[578] 761 F.2d 768 (D.C. Cir. 1985).

[579] *E.g.*, VA Com, DE Muni, LG&E, Mountain States Petroleum Assoc.

[580] ELCON July 25, 1995 Comments at 6.

[581] Hereafter referred to collectively as the ''new open access'' or ''open access transmission.''

[582] FERC Stats. & Regs. ¶ 32,514 at 33,101–02.

[583] Contrary to NRRI's claim, and as explained in the NOPR (*see, e.g.*, FERC Stats. & Regs. ¶ 32,514 at 33,063–68), the electric industry's transition to a more competitive market *is* driven in large part by statutory and regulatory changes beyond the utilities' control.

customer is radically increased. If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, we believe that the utility is entitled to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer.[584]

We learned from our experience with natural gas that, as both a legal and a policy matter, we cannot ignore these costs. During the 1980s and early 1990s, the Commission undertook a series of actions that contributed to the impetus for restructuring of the gas pipeline industry. The introduction of competitive forces in the natural gas supply market as a result of the Natural Gas Policy Act of 1978[585] and the subsequent restructuring of the natural gas industry left many pipelines holding uneconomic take-or-pay contracts with gas producers. When the Commission initially declined to take direct action to alleviate that burden, the U.S. Court of Appeals for the District of Columbia Circuit faulted the Commission for failing to do so.[586] The court noted that pipelines were ''caught in an unusual transition'' as a result of regulatory changes beyond their control.[587]

As we stated in the Supplemental NOPR, the court's reasoning in the gas context applies to the current move to a competitive bulk power industry. Indeed, because the Commission failed to deal with the take-or-pay situation in the gas context, the court invalidated the Commission's first open access rule for gas pipelines. Once again, we are faced with an industry transition in which there is the possibility that certain utilities will be left with large unrecoverable costs or that those costs will be unfairly shifted to other (remaining) customers. That is why we must directly and timely address the costs of the transition by allowing utilities to seek recovery of legitimate, prudent and verifiable stranded costs. At the same time, however, this Rule will not insulate a utility from the normal risks of competition, such as self-generation, cogeneration, or industrial plant closure, that do not arise from the new availability of non-discriminatory open access transmission. Any such costs would not constitute stranded costs for purposes of this Rule.

We are issuing the Stranded Cost Final Rule simultaneously with the Open Access Final Rule because we believe that the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment. We believe that our decision today will be upheld by the courts. While the D.C. Circuit is still considering the various appeals of Order No. 636,[588] it has already upheld, in at least two instances, our ultimate decision to allow the recovery of costs stranded in the transition to a competitive natural gas industry.[589] As a result, we reject the suggestions of some commenters that a utility's obligation to comply with the provisions of the Open Access Final Rule should be conditioned upon final court approval of the Stranded Cost Final Rule. We also decline otherwise to condition a utility's ability to recover its stranded costs. As described in greater detail in Section IV.J.8, if a utility can make the necessary evidentiary showings, it will be eligible for stranded cost recovery.

With regard to the magnitude of potential wholesale stranded costs, as the Supplemental Stranded Cost NOPR recognizes, the level may be small relative to that of retail stranded costs. Nevertheless, wholesale costs may be stranded as a result of open access transmission. Because the significance of such costs to the utilities that would face them may be great (and the prospect of not recovering such costs could erode utilities' ability to attract capital and be very detrimental to a diverse array of utility shareholders), we believe that we have a responsibility to allow for the recovery of such costs.

We disagree with the commenters who contend that this Rule would discriminate against certain segments of the industry, such as non-transmission-owning utilities (who would not be allowed to collect stranded costs) or wholesale requirements customers (who would be subject to stranded cost charges while other wholesale customers would not). These commenters misconstrue the purpose of this Rule and the nature of the stranded costs for which this Rule would allow recovery. This rule is designed to address a new and specific problem: The fact that a utility that historically has supplied bundled generation and transmission services to a wholesale requirements customer and incurred costs to meet reasonably expected customer demand may experience stranded costs when its customer is able to reach a new generation supplier due to the availability of open access transmission. This rule proposes a solution to that problem by allowing the recovery of legitimate, prudent and verifiable costs incurred by a utility to provide service to a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of the utility. The opportunity for extra-contractual wholesale stranded cost recovery is allowed for only a discrete set of requirements contracts for which the utility can demonstrate that it had a reasonable expectation of continuing service, as well as for retail-turned-wholesale situations in which the utility satisfies the necessary evidentiary criteria. Thus, the fundamental premise of this rule—namely, that a utility should have an opportunity to recover reasonably-incurred costs that arise because open access use of the utility's transmission system enables a generation customer to shop for power—would not apply to a non-transmission-owning utility that, by definition, has no transmission by which its generation customer can escape to another supplier.

The same historical relationship discussed above, including the expectation of continued service, justifies imposing the stranded costs covered by this rule on wholesale requirements customers only (not on non-requirements customers that contract separately for transmission services to deliver their purchased power). Requirements customers historically were long-term customers who typically did not expect to take service from other suppliers. Utilities thus assumed they would continue

[584] As a result, the opportunity for wholesale stranded cost recovery under this Rule is limited to utilities that provided sales of generation and transmission under wholesale requirements contracts, and to utilities that provided service to retail customers that convert to wholesale customer status, and that face the potential inability to recover costs when their customers are able to reach new suppliers through open access transmission.

[585] 15 U.S.C. 3301 *et seq.*

[586] *AGD*, 824 F.2d at 1021.

[587] *Id.* at 1027.

[588] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 FR 13267 (April 16, 1992), FERC Stats. & Regs. ¶ 30,939 (1992), *order on reh'g,* Order No. 636–A, 57 FR 36128 (August 12, 1992), FERC Stats. & Regs. ¶ 30,950 (1992); *order on reh'g,* Order No. 636–B, 57 FR 57911 (December 8, 1992), 61 FERC ¶ 61,272 (1993), *reh'g denied,* 62 FERC ¶ 61,007 (1993), *appeal pending* United Distribution Companies, *et al.*, v. FERC, No. 92–1485, *et al.*, (D.C. Cir. Oral Argument Held Feb. 21, 1996).

[589] *See, e.g.,* Public Utilities Commission of the State of California v. FERC, 988 F.2d 154, 166 (D.C. Cir. 1993) (''FERC, with the backing of this court, has been at pains to permit pipelines to recover these (take-or-pay) costs, which have accumulated less through mismanagement or miscalculation by the pipelines than through an otherwise beneficial transition to competitive gas markets.''); Western Resources, Inc. v. FERC, 72 F.3d 147 (D.C. Cir. 1995).

serving these customers and may have made significant investments based on that long-term expectation. In contrast, utilities did not (and do not today) generally make investments for short-term economy-type transactions. Rather, such transactions were entered into only when the utility temporarily had available capacity or energy that could be provided to the buyer at a price lower than the buyer's decremental cost. The utility was not obligated in any way—either explicitly or implicitly—to provide for the needs of non-requirements customers. Because coordination transactions were not the cause of stranded investment decisions, it would be inappropriate to allocate such costs to non-requirements customers.

Further, although some commenters object that the Rule would give public utilities a greater opportunity than other transmitting utilities to recover stranded costs, our jurisdiction over transmitting utilities that are not also public utilities is limited. If the selling utility under an existing contract is a transmitting utility that is not also a public utility, its wholesale requirements contracts are not subject to this Commission's jurisdiction. Thus, we can allow such a transmitting utility to recover stranded costs only through Commission-jurisdictional transmission rates under sections 211 and 212 of the FPA. Nevertheless, in the context of a specific section 211 case, we would expect to apply similar principles to the extent possible to assure full stranded cost recovery. We also encourage such transmitting utilities to negotiate mutually agreeable stranded cost provisions with their customers.

2. *Cajun Electric Power Cooperative, Inc.* v. *FERC* [590]

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary finding that the *Cajun* court decision does not bar the recovery of stranded costs as proposed in the NOPR and set forth our reasoning in support of that finding.[591]

Comments

Various commenters contend that the proposal to permit recovery of stranded costs at all, or particularly through transmission rates of departing customers, fails to address the *Cajun* court's concerns.[592] These commenters repeat many of the same arguments previously raised in this proceeding, which we have already addressed. Some commenters argue that including generation-based stranded costs in transmission rates is an anticompetitive tying arrangement and that *Cajun* compels the Commission to abandon this aspect of its stranded cost proposal or, at a minimum, to explain how the chosen method of recovery differs from that remanded in *Cajun*.[593]

Several commenters [594] question whether the NOPR's stranded cost provisions would undermine the ''meaningful'' access to alternative suppliers referenced by the *Cajun* court.[595] For example, Arkansas Cities asserts that the Commission has failed to address whether a transmitting utility retains market power over transmission even after imposition of an open access tariff. It contends that this question is vital to determining whether imposition of stranded costs would interfere with a wholesale transmission customer's meaningful access to other power suppliers.

Some commenters also submit that the proposed procedures for a customer to obtain an estimate of its stranded cost liability are inadequate because they do not ameliorate the uncertainty confronting the customer, which was a concern of the court in *Cajun*. They suggest that a customer would still face the prospect of litigation concerning whether a proposed stranded cost charge is appropriate.[596]

Other commenters argue that *Cajun* requires a trial-type evidentiary hearing before stranded costs may be recovered. They question whether the Commission's generic proposals on open access and the Commission's statements about the need to recover stranded costs are adequate.[597] ELCON references the *Cajun* court's statement that ''if the Commission is wrong at the outset concerning the *possibility* of legitimate stranded investment cost, it is not fair or reasonable to create such a mechanism for recovery.'' [598] ELCON submits that the factual record does not demonstrate any significant wholesale stranded cost problem and, as a result, a final rule allowing recovery of such costs would not be ''fair or reasonable.''

Many other commenters, in contrast, believe that the NOPR is distinguishable from the case that was before the court in *Cajun* and that the Commission has fully addressed the *Cajun* court's concerns. According to the Coalition for Economic Competition, this proceeding is very different from the *Cajun* proceeding because the proposed rule would not automatically permit utilities to charge market-based rates. The Coalition for Economic Competition states that in the absence of generic market-based rate authorization, there is no basis in *Cajun* for barring the recovery of stranded investment in transmission tariffs.[599]

A number of commenters agree with the Commission that the *Cajun* court was concerned with the need for a more complete explanation of the basis for stranded cost recovery and the mechanism selected for such recovery. These commenters believe that the NOPR provides both the evidentiary record for addressing these concerns on a generic basis and the opportunity for all participants to present evidence and arguments.[600]

Noting the *Cajun* court's concern as to whether the wholesale customer in that case had ''meaningful'' access to alternative suppliers, a number of commenters agree that the Commission, through the open access provisions of the NOPR, is in fact providing wholesale customers meaningful, reasonable access to alternative suppliers.[601]

As evidence that the *Cajun* court was concerned with inadequate explanation and procedures and did not find that stranded costs could never be justified, several commenters point out that the *Cajun* court did not mention the D.C. Circuit's landmark decision in *AGD*, which strongly supports stranded cost

[590] 28 F.3d 173 (D.C. Cir. 1994) (*Cajun*).

[591] FERC Stats. & Regs. ¶ 32,514 at 33,105–06.

[592] *E.g.*, APPA, ABATE, ELCON, Central Illinois Light, IL Com, VT DPS.

[593] *See, e.g.*, ELCON, American Forest & Paper, MMWEC, Cajun, IL Com, PA Com, VT DPS, Education, DE Muni, IN Industrials, Texas-New Mexico, Las Cruces, Blue Ridge, Suffolk County, Total Petroleum, NM Industrials, PA Munis.

[594] *E.g.*, Arkansas Cities, PA Munis, NM Industrials.

[595] *See Cajun*, 28 F.3d at 179.

[596] *See, e.g.*, Suffolk County, Arkansas Cities, Education.

[597] *E.g.*, PA Com, NY Com, RUS.

[598] *Cajun*, 28 F.3d at 179 (emphasis in original).

[599] SC Public Service Authority notes this distinction as well (Initial Comments at 78): ''In *Cajun*, the court was not criticizing the recovery of stranded assets as an abstract matter, but specifically as an integral part of a set of tariffs designed to justify market-based rates on the basis that the open access tariff adequately mitigated market power despite the provision permitting recovery of stranded assets.'' It suggests that if the Commission decides to allow utilities to recover stranded costs from departing customers, any utility recovering such costs should not be allowed to charge market-based rates.

[600] *See, e.g.*, EEI, NEPCO, Centerior, Electric Consumers Alliance, Southern.

[601] *E.g.*, Omaha PPD, Com Ed, Florida Power Corp. Com Ed also submits that the argument by the petitioners in *Cajun* that ''there really is no such thing as stranded investment, only a failure to compete'' ignored the circumstances under which the investments were made. It states that electric utilities did not incur the costs of generation facilities (and long-term fuel and power supply contracts) because they were less efficient competitors, but to satisfy their obligation in a fully-regulated market to provide service to all who request it.

recovery.[602] For example, Coalition for Economic Competition suggests that construing *Cajun* to hold that stranded cost recovery is always anticompetitive would be at odds with *AGD* and other decisions that have upheld the Commission's policy of allowing recovery of the costs of the transition to competitive markets.[603]

Numerous commenters also support the Commission's conclusion that stranded cost recovery through transmission rates is not a tying arrangement.[604] Among other things, these commenters argue that a tying claim requires that the defendant force the sale of a separate product with the sale of a product over which it has market power, and that here there is no second product being tied to transmission. Several commenters also suggest that, in any event, stranded cost recovery as proposed in the NOPR would be considered a legitimate business justification under the antitrust laws.[605] Com Ed explains that the Commission, as part of its effort to enhance competition in generation by opening up the transmission network, is avoiding placing on utilities the entire burden of the stranded costs resulting from their past regulatory obligations; it is not permitting utilities to maintain a monopoly of power sales.

Commission Conclusion

We reaffirm that we do not interpret the *Cajun* court decision as barring the recovery of stranded costs. The court in that case did not bar stranded cost recovery, as some commenters suggest; it instead found that the Commission had not provided adequate proceedings and had not fully explained its decision. The Commission had failed to hold an evidentiary hearing concerning whether the inclusion of a stranded cost recovery provision in a particular utility's transmission tariff, along with other provisions in the tariff, resulted in the adequate mitigation of Entergy's market power so as to justify market-based rates. The court also found that the Commission had failed to explain adequately its approval of the stranded cost provision, among other provisions. In contrast, as discussed below, we have addressed in this consolidated proceeding (the Stranded Cost NOPR, the Supplemental Stranded Cost NOPR, the Open Access NOPR, and the Open Access/Stranded Cost Final Rule) all of the *Cajun* court's concerns.

Our interpretation of *Cajun* is bolstered by a recent opinion of the Court of Appeals for the D.C. Circuit (the same circuit that decided *Cajun*) that confirms the validity of Commission imposed stranded cost recovery mechanisms in the transition to competitive markets. In *Western Resources, Inc.* v. *FERC*,[606] the court affirmed the Commission's decision to allow the recovery of costs stranded in the transition of the natural gas industry to a competitive market.[607] We believe that, by this decision, the court has again affirmed the Commission's ability to allow stranded cost recovery, as long as we follow adequate procedures and explain our decision.[608]

We are providing in this proceeding the evidentiary record to support our decision to allow the recovery of legitimate, prudent and verifiable stranded costs on a generic basis. We also are ensuring the ''meaningful'' access to alternative suppliers that was identified as a concern of the *Cajun* court. The Open Access Final Rule is designed to attack one essential element of market power—namely, control over transmission access. The standard we are adopting for transmission service is far stricter than the standard we used at the time *Cajun* was decided; we now require non-discriminatory open access transmission, as well as a code of conduct and non-discriminatory sharing of transmission information (OASIS). The collective effect of these actions is that public utilities that own, control or operate interstate transmission facilities will not be able to favor their own generation and will have to compete on an equal basis with other suppliers.[609] All public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce will have tariffs on file that offer to any eligible customer any transmission services that the public utility could provide to itself, and under comparable terms and conditions.

We note that the *Cajun* court identified several provisions in Entergy's proposed tariff as potentially restraining competition: Entergy's retention of sole discretion to determine the amount of transmission capability available for its competitors' use;[610] the point-to-point service limitation;[611] the failure to impose reasonable time limits on Entergy's response to requests for transmission service;[612] and Entergy's reservation of the right to cancel service in certain instances,[613] even where a customer had paid for transmission system modifications.[614] These types of provisions, which have the potential to restrain competition, will not be allowed under the Open Access Rule. On the contrary, the Final Rule pro forma tariff contains terms and conditions to ensure the provision of non-discriminatory transmission service. In addition, the requirements that a public utility take service under its own tariff, adopt a non-discriminatory transmission information network, and separate power marketing and transmission functions further ensure non-discrimination and remove constraints to fair competition. Thus, the nondiscriminatory open access

[602] *See, e.g.*, Com Ed, Coalition for Economic Competition, NYSEG, Entergy.

[603] *See, e.g.*, K N Energy, Inc., 968 F.2d 1295 at 1301 (D.C. Cir. 1992), Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 874 (D.C. Cir. 1993).

[604] *E.g.*, EEI, Com Ed, Consumers Power, SoCal Edison, Salt River, Entergy.

[605] *See* State of Illinois ex rel. Burris v. Panhandle Eastern Pipe Line Co., 935 F.2d 1469, 1483 (7th Cir. 1991), *cert. denied*, 502 U.S. 1094 (1992) (pipeline's refusal to transport gas that an LDC customer purchased from another supplier was ''genuinely and reasonably motivated by the need to limit its potential take-or-pay liability, not by a desire to maintain its monopoly position by excluding competition in the sale of natural gas''); City of Chanute v. Williams Natural Gas Company, 743 F. Supp. 1437 (D. Kan.), *aff'd*, 955 F.2d 641 (7th Cir. 1990) (pipeline's refusal to transport third-party gas was motivated by legitimate business concerns, including desire to prevent take-or-pay liability, not by an anticompetitive motive).

[606] 72 F.3d 147 (D.C. Cir. 1995).

[607] *Id.* at 152.

[608] As we noted in the Supplemental NOPR, the same court had earlier instructed the Commission in the *AGD* case that the Commission *must* consider the transition costs borne by regulated utilities when the Commission changes the regulatory rules of the game. FERC Stats. & Regs. ¶ 32,514 at 33,106.

[609] *Id.* at 33,065–67.

[610] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff provides that available transmission capability (ATC) must be calculated and posted on the transmission provider's Open Access Same-time Information System (OASIS) pursuant to new Part 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEM AND STANDARDS OF CONDUCT FOR PUBLIC UTILITIES of the Commission's regulations. Section 37.6 provides in pertinent part that along with posting its ATC on its OASIS node, a public utility must make all data used in the calculation publicly available, on request. Section 37.4 provides that employees of the public utility and any affiliate that are engaged in merchant functions are prohibited from having preferential access to any transmission-related information. Additionally, the regulations provide auditing and monitoring procedures to safeguard against discriminatory practices.

[611] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff requires the provision of point-to-point and network service.

[612] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff requires reasonable time limits for responses to transmission requests. Specifically, Section 17.5 provides that a transmission provider must respond to a request for firm service as soon as practicable, but not later than thirty days after the date of receipt of a completed application.

[613] In contrast to the tariff under review in *Cajun*, the Final Rule pro forma tariff does not allow firm transmission service to be cancelled after the service has been commenced. However, Section 7.3 of the Final Rule pro forma tariff does provide that in the event of a customer default, the transmission provider may, in accordance with Commission policy, file and initiate a proceeding with the Commission to terminate service.

[614] *Cajun*, 28 F.3d at 179–80.

transmission that is the hallmark of this Rule is designed to ensure meaningful access to alternative suppliers and goes far beyond that which was offered in the transmission tariff that was under review in *Cajun*.

We also have addressed the *Cajun* court's concern over the *method* of recovery. In that case, Entergy proposed to include a charge in the departing customer's transmission rate to recover its stranded investment costs. The court said that this might constitute an anticompetitive tying arrangement.[615] As we explained in the Supplemental NOPR, the stranded cost recovery procedure we prescribe in this Rule is a *transitional mechanism only* that is intended to enable utilities to recover costs prudently incurred under a different regulatory regime. The purpose and effect of the stranded cost recovery mechanism that we approve in this Rule is to facilitate the transition to competitive wholesale power markets. Although we recognized in the Supplemental NOPR that stranded cost recovery may delay some of the benefits of competitive bulk power markets for some customers, such transition costs must nevertheless be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. The stranded cost recovery mechanism that we direct here is a necessary step to achieve pro-competitive results. In the long term, the Commission's rule will result in more competitive prices and lower rates for consumers.

The Commission's approach also is consistent with the traditional regulatory concept of cost causation. We do not believe it is an illegal tying arrangement to hold a customer accountable for the consequences of leaving an incumbent supplier if, under our rules, the incumbent supplier must show a reasonable expectation of continuing service before it can recover stranded costs from the customer.

Further, in response to the *Cajun* court's concern that the Commission had failed in that case to explain adequately its approval of the stranded cost provision and other provisions, we have provided in this proceeding a detailed explanation of the fundamental industry and regulatory changes that have given rise to the potential for stranded costs; the transitional nature of stranded costs; the critical need to deal with these costs in order to reach more competitive wholesale markets; and the consumer benefits that will result from competitive generation markets. We also have provided a detailed explanation of the terms and conditions in the Final Rule pro forma tariff that will meet the non-discriminatory open access service requirement.

Several commenters (and the *Cajun* court) express concern for the need to provide as much certainty as possible for departing customers concerning their potential stranded cost obligation. Without some certainty, customers may be unable to shop for alternative suppliers. In response to these concerns, we have modified the stranded cost recovery mechanism to include a formula for calculating a departing customer's potential stranded cost obligation. As discussed in greater detail in Section IV.J.9, the revenues lost formula is designed to provide certainty for departing customers and to create incentives for the parties to address stranded cost claims between themselves without resort to litigation.

We conclude that we have fully explained our decision to allow the recovery of legitimate, prudent and verifiable costs that are stranded in the transition to competitive wholesale bulk power markets. We also have provided ample opportunity for all concerned to present arguments and evidence on the issue. Further, we have significantly strengthened our open access requirements to ensure mitigation of transmission market power. Thus, we have fully addressed the concerns of the *Cajun* court.

3. Responsibility for Wholesale Stranded Costs (Whether To Adopt Direct Assignment to Departing Customers)

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary finding that direct assignment of stranded costs to the departing wholesale generation customer is the appropriate method for recovery of such costs.[616]

Comments

Numerous parties representing all constituencies support direct assignment of stranded costs to the departing generation customer.[617] These commenters argue, among other things, that direct assignment is consistent with the cost causation principle and preferable to increasing the delivered price of electricity to a whole region through the imposition of a wires charge, and that recovery of stranded costs from remaining customers would not be in the public interest. Several state commenters seek assurance from the Commission that native load customers will be held harmless from stranded costs resulting from other customers leaving the system.[618] KY Com submits that the possible results of a broader assessment of stranded costs, with the related uncertainty of its impact on the utilities' cost of capital, is more problematic in the long run than the possibility that the direct assignment of stranded costs would deter customers from shopping for power.

Although TAPS opposes stranded cost recovery in general, it submits that, if the Commission decides to allow recovery, the Commission should directly assign stranded costs and not spread them across the board to all transmission users.

Several commenters also oppose any allocation of stranded cost liability to shareholders.[619]

Some commenters state that direct assignment of stranded costs sends the correct pricing signals during the transition to a competitive regime. For example, Electric Consumers Alliance states that a wholesale customer should be able to obtain power elsewhere, but that the motive to do so should not be to escape responsibility for sunk investments made on its behalf. El Paso submits that failure to make the departing generation customer liable for stranded cost recovery would create a ''first-off'' incentive; the customers that leave the system first would not suffer from higher future rates designed to recover prudently incurred costs from the reduced base of remaining customers.

Some commenters support direct assignment but oppose recovery of stranded costs through transmission rates. These commenters prefer an exit fee or lump-sum approach that would reflect cost causation in an unbundled fashion.[620] DOJ maintains that a

615 Notably, the court stated: ''This is, in essence, a tying arrangement, (citation omitted), and *it might be fine if the purpose of the arrangement were not to cabin Entergy's market power.'' Id.* at 177–78 (emphasis added).

616 FERC Stats. & Regs. ¶32,514 at 33,108.

617 *See, e.g.*, EEI, Atlantic City, Arizona, Carolina P&L, Centerior, Com Ed, Duke, HP&L, Duquesne, Florida Power Corp, Omaha PPD, Alcoa, AEC & SMEPA, BG&E, Central Electric, Detroit Edison, El Paso, Montana-Dakota Utilities, Ohio Edison, PECO, PSNM, Southern, Sierra, SoCal Edison, Tucson Power, Utilities For Improved Transition, Cajun, NRECA, EGA, Electric Consumers Alliance, FL Com, PA Com, Knoxville, Salt River, KY Com, ND Com, California DWR, LA DWP, TVA, Utility Investors Analysts, Texas Utilities, LG&E, Utility Shareholders.

618 *E.g.*, NC Com, UT Com, NJ Ratepayer Advocate.

619 *E.g.*, SCE&G, Com Ed, Ky Com, NC Com. SCE&G states that the Commission misinterpreted its previous comments by suggesting in the Supplemental NOPR that SCE&G believed shareholders should bear part of the costs.

620 *E.g.*, Texas Utilities, DOJ.

transmission adder is analogous to an excise tax and that the excise tax approach would distort pricing signals and customers' decisions on the use of electric power. It submits that the lump-sum approach, on the other hand, would establish a fixed, sunk liability that would not depend upon how much transmission service the departing customer takes in the future.[621]

Other commenters oppose direct assignment as being inconsistent with wholesale competition.[622] They argue that placing all of the responsibility for stranded costs on departing generation customers would discourage customers from switching to other generation providers and would thereby inhibit competition.[623] Some commenters also assert that departing generation customers are not the sole ''cause'' of stranded costs.[624] VT DPS contends that direct assignment cannot be reconciled with the Commission's refusal to allow the imposition of exit fees by gas pipelines when their wholesale customers depart.[625]

Some commenters support spreading the burden of stranded costs broadly among departing customers, shareholders, and remaining wholesale customers on the basis that it would be equitable for all industry stakeholders to share both the benefits and the costs of the transition to competition.[626]

Others support spreading the costs to all customers through, for example, a meter charge to all utilities (to be passed on to customers), a one-time charge across the total market base, an access fee on the transmission system, or a component of transmission rates.[627] Nordhaus proposes a uniform national tax on all customers, at a rate that declines over time in a predetermined manner. He submits that this approach would remove ''gaming'' between utilities and potential exiters, would ensure that the stranded costs are not disproportionately loaded on price-sensitive demanders (that is, exiting customers), and would gradually disappear over time in a predictable fashion, thereby increasing the predictability of the new market.

PA Munis disputes the Commission's assertion in the Supplemental Stranded Cost NOPR that there is no compelling reason to assess costs broadly. It argues that a broad-based recovery mechanism that distributes uneconomic stranded costs to all power users would minimize the competition-inhibiting aspects of the Commission's proposed surcharge on departing generation customers. In a similar fashion, NSP states that across-the-board recovery from all users of the grid would recognize the societal benefits to be achieved from the transition to a competitive bulk power market and would reflect precedent set during the move to competition in the natural gas and telephone industries. It submits that the cost per service unit would be lower than exit fees assigned to particular customers and would eliminate the need for detailing stranded cost exposure for each customer contemplating leaving the system.

FTC submits that some investments that now appear as stranded costs may have been intended to benefit customers over a wider area than a single utility. It suggests that national regional assessment methods could recover stranded costs undertaken to benefit these wider groups of customers.

We also received comments suggesting that less than full recovery of stranded costs should be allowed. A number of commenters urge the Commission to require some shareholder liability for stranded cost recovery to give utilities an incentive to mitigate.[628] Several of these commenters assert that utility shareholders should be required to pay a portion of any stranded costs (such as 25–50 percent) because at least some of the responsibility for stranded costs lies with poor business decisions by utility management.[629] Occidental Chemical proposes that the Commission grant utilities a ''presumption of prudence'' in return for requiring them to absorb a minimum of 25 percent (up to 50 percent) of stranded costs, citing as support the Commission's precedent in the natural gas industry.

Commission Conclusion

We reaffirm our decision that direct assignment of stranded costs to the departing wholesale generation customer through either an exit fee[630] or a surcharge on transmission is the appropriate method for recovery of such costs. We believe it is appropriate that the departing generation customer, and not the remaining generation or transmission customers (or shareholders), bear its fair share of the legitimate and prudent obligations that the utility undertook on that customer's behalf.

In reaching this decision, we have carefully weighed the arguments supporting direct assignment of stranded costs against those supporting a more broad-based approach, such as spreading stranded costs to all transmission users of a utility's system.

[621] In its reply comments, Utility Working Group disputes DOJ's arguments that a transmission adder is analogous to an excise tax and would distort competition. It argues that DOJ's claim of price distortion ignores the fact that the costs that would be associated with a transmission adder consist of a portion of the previous wholesale power price—the markup above the utility's marginal cost that had regulatory approval. Utility Working Group says that because the utility's price and its competitor's price will contain this same charge for the utility's sunk and regulatory costs (the difference between the utility's regulated rate and its incremental cost), they will compete on the basis of their respective incremental costs. It also suggests that transmission adders can be designed on a lump-sum basis so that they are not tied to the amount of electricity purchased.

[622] *E.g.*, ELCON, NYMEX, IL Industrials, Missouri-Kansas Industrials, Philip Morris, Fertilizer Institute, Coalition on Federal-State Issues.

[623] Some commenters also oppose the Commission's proposal to allow the recovery of generation-related costs through transmission rates as being in contravention of cost-causation principles (*e.g.*, VT DPS) or in violation of section 212(a) of the FPA, which they contend limits cost recovery to transmission-related costs (*e.g.*, IL Industrials, Las Cruces).

[624] *E.g.*, ELCON, IL Industrials, NY Energy Buyers, TX Industrials, Missouri-Kansas Industrials, Caparo, IBM, PA Munis, Education. For example, Caparo submits that business decisions by incumbent utilities are the cause of stranded costs.

[625] In support of this proposition, the VT DPS cites Transwestern Pipeline Co., 44 FERC ¶61,164 at 61,536 (1988); El Paso Natural Gas Co., 47 FERC ¶61,108 at 61,314 (1989); El Paso Natural Gas Co., 72 FERC ¶61,083 (1995). It also contends that the Commission recently treated a notice provision in an El Paso contract as a conclusive, rather than a rebuttable, presumption. VT DPS cites other differences between the Commission's treatment of the natural gas and the electric utility industries. It notes that the Commission has not proposed to allow existing wholesale electric customers to get out of their contracts early, as it did in the gas area.

[626] *E.g.*, ELCON, IN Industrials, Reynolds, Philip Morris, ABATE, Missouri-Kansas Industrials, Aluminum.

[627] *See, e.g.*, American National Power, NIEP, NSP, SBA, Coalition on Federal-State Issues, Pennsylvania P&L, Consolidated Natural Gas, Nordhaus, PA Munis. Consumers Power states that it does not oppose direct assignment, but asks that the final rule not preclude utilities from proposing alternative recovery mechanisms, including those that assess stranded costs on all transmission customers as part of the transmission rate. It suggests that utilities should not be precluded from showing that there may be countervailing reasons to assess stranded costs broadly among all transmission customers (*e.g.*, where the costs assignable to a particular customer or group of customers may be so high as to create a dispute as to the propriety of direct assignment).

[628] *See, e.g.*, American Forest & Paper, Torco, Philip Morris, DE Muni, MT Com, IL Com, KS Com, Fertilizer Institute, Caparo, Las Cruces, IN Com, PA Munis, San Francisco, NRRI, Competitive Enterprise, ELCON, IN Industrials, UT Industrials, NY Energy Buyers, ABATE, CA Energy Co, Caparo, Education, Reynolds.

[629] *See, e.g.*, Fertilizer Institute, Caparo, DE Muni, PA Munis, MT Com, San Francisco, ELCON, IN Industrials, NY Energy Buyers.

[630] As used in this Rule, ''exit fee'' refers to the charge that will be payable by a departing generation customer upon the termination of its requirements contract with a utility (if the utility is able to demonstrate that it reasonably expected to continue serving the customer beyond the term of the contract), whether payable in a lump-sum payment or an amortization of a lump-sum payment. (The same charge also can be paid as a surcharge on the customer's transmission rate.)

Recognizing that each approach has advantages and disadvantages, we conclude that, on balance, direct assignment is the preferable approach for both legal and policy reasons.

One of the main reasons to adopt direct assignment of stranded costs is that direct assignment is consistent with the well-established principle of cost causation, namely, that the party who has caused a cost to be incurred should pay it. Direct assignment of stranded costs to departing generation customers is particularly appropriate given the nature of the stranded cost recovery mechanism contained in this Rule, which links the incurrence of stranded costs to the decision of a particular generation customer to use open access transmission to leave the utility's generation system and shop for power, and which bases the prospect of stranded cost recovery on the utility's ability to demonstrate that it incurred costs with the reasonable expectation that the customer would remain on its generation system.

A broad-based approach, in contrast, would violate the cost causation principle by shifting costs to customers (such as transmission users of the utility's system) that had no responsibility for stranding the costs in the first place. In addition, if the Commission were to adopt a broad-based approach, it would have to determine whether to base the transmission surcharge on all users of a utility's transmission system on a one-time, up-front estimate of stranded costs (that is, each utility claiming stranded costs would make a one-time, comprehensive determination of stranded costs for the utility as a whole) or on an as-realized basis (the surcharge would be based on actual customer departures and would be adjusted each time a customer departs). Each option would have disadvantages that are not present in the direct cost causation approach we are adopting.

For example, a major disadvantage of an up-front, broad-based transmission surcharge is that it in effect would charge customers for costs before the costs are incurred (*i.e.*, before customers have even decided to leave the utility's generation system) and could charge for costs that may never be incurred (*e.g.*, some customers may decide to stay on the utility's system as requirements customers). The other option, a broad-based transmission surcharge that would be adjusted as customers leave the utility's system, also has disadvantages. While this option might recover stranded costs that are closer to the actual amount incurred by the utility, it could produce variability in transmission rates every time stranded costs from a newly-departed customer are included in the transmission surcharge and, in turn, could possibly hamper efficient power supply choices and efficient generator location decisions. These disadvantages are not present in the direct assignment approach.

Direct assignment will result in a more accurate determination of a utility's stranded costs than would an up-front, broad-based transmission surcharge. This is because the stranded cost for any customer is finally determined only if that customer actually leaves a utility. Moreover, there is no stranded cost unless the then-current market price of power for the period that the utility reasonably expected to continue serving the customer is below the utility's cost. Thus, because the circumstances of each departing customer will be known, the amount of any stranded cost liability can be determined with reasonable accuracy. Further, if a customer does not leave the utility or leaves at some future time when the utility's costs are competitive, the issue need not be addressed.

On this basis, the direct assignment approach is more suited to the recovery of stranded costs as defined in this Rule (including the reasonable expectation standard and open access transmission causation requirement) than is a broad-based approach. We expect that a utility would have difficulty estimating in advance all of its stranded costs for purposes of an up-front, broad-based transmission surcharge. In the face of this uncertainty, the utility's best strategy likely would be to try to recover through the broad-based surcharge as much of its uneconomic assets as possible by claiming that all of its wholesale customers are likely to depart and to leave large stranded costs. In this regard, the broad-based approach would provide an incentive for a utility to try to recover the costs of all of its uneconomic assets whether or not they were prudently incurred. This is in contrast to what this Rule provides, which is for recovery of only those legitimate, prudent and verifiable costs that were incurred on behalf of a specific customer based on a reasonable expectation that the utility would continue to serve the customer and that are stranded when the customer departs the utility's generation system by using the utility's open access transmission.

The direct assignment approach also can be readily applied to both wholesale and retail-turned-wholesale departing customers. It also can be adapted for retail customers. Further, it works for costs stranded by a section 211 order requiring either a public utility, or a transmitting utility that is not also a public utility, to provide transmission service. However, this is not the case for a broad-based approach, particularly an up-front, broad-based approach. Assuming that a principal motivation for an up-front, broad-based approach would be to recover all of a utility's stranded costs as quickly as possible, retail-turned-wholesale stranded costs nevertheless are not susceptible of being collected on an up-front basis. It is not possible to make a realistic up-front estimate of costs stranded by municipalizations that may occur in the future. Thus, even if we were to adopt an up-front, broad-based approach for recovering costs that are stranded when wholesale requirements customers use their former supplier's transmission system to reach a new supplier, retail-turned-wholesale stranded costs would have to be identified as they occur and the stranded cost surcharge on transmission users adjusted accordingly. Similarly, the broad-based approach is not easily adaptable to transmitting utilities that are not also public utilities. It is doubtful that, in establishing the rate for a section 211 applicant, the Commission could also set transmission surcharges for customers that were not section 211 applicants; this is what a broad-based approach, in effect, would require us to do.

Direct assignment by means of an exit fee or a transmission surcharge that is not dependent on any subsequent power or transmission purchases by the customer is also an economically efficient way to collected stranded costs. The customer may make a lump-sum stranded cost payment, amortize the lump-sum payment, or spread the payment as a surcharge in addition to its transmission rate. The total amount of stranded costs that the directly-assigned customer ultimately pays would not depend on how much transmission service it takes and thus would not influence the customer's subsequent transmission purchase decisions.

With a broad-based surcharge (which could be demand- or usage-based), on the other hand, the surcharge for transmission users would depend on how much transmission service the users take. A broad-based approach also would be inefficient as it would raise the price of transmission service for all customers, thereby potentially cutting off some beneficial power trading that would otherwise occur for all unbundled transmission customers. The surcharge also could convert some profitable existing power purchase contracts into unprofitable contracts. In addition, it could reduce economy trading because the surcharge would be added to the price of economy transmission. In this manner, a broad-based surcharge would constitute a cross-subsidy that could distort the market.

We recognize that direct assignment is not without its potential drawbacks. For example, when compared to an up-front, broad-based transmission surcharge approach, direct assignment may entail a longer stranded cost recovery period. The transition period for stranded cost recovery under a direct assignment approach would depend on the length of the remaining terms of the wholesale requirements contracts for which this Rule provides an opportunity for recovery (contracts executed on or before July 11, 1994 that do not contain an exit fee or explicit stranded cost provision).

On the other hand, a broad-based approach could identify and recover stranded costs earlier than the direct assignment approach; recovery of stranded costs for all of a utility's wholesale requirements customers could begin as soon as the utility's up-front stranded cost amount for departing wholesale customers is determined (through litigation or settlement). However, this potential advantage of a broad-based approach (the shorter transition period) is outweighed by what we believe to be a serious infirmity, namely, the possibility that the broad-based transmission surcharge could end up including costs that have not yet been incurred and may never be incurred.

In addition, another potential drawback to the direct assignment approach is that the departing generation customer may see little or no savings in the short-term by switching power suppliers once its stranded cost exit fee is added to its lower power price from a new supplier. Direct assignment may leave the customer uncertain about the benefits of shopping for power because of the customer's potential stranded cost liability and, in turn, may bias the customer toward staying with its existing power supplier.[631]

In the case of a broad-based approach, in contrast, much of the customer's direct assignment stranded costs are spread to others through a transmission surcharge. As a result, the departing generation customer's power cost savings may more than offset the customer's stranded cost transmission surcharge. The customer may therefore see earlier power cost savings if a broad-based approach were adopted.[632] Once again, however, we believe that this potential benefit to a broad-based approach is outweighed by a significant countervailing disadvantage. In particular, the potential power cost savings to the departing generation customer would be realized only by shifting costs (that are directly attributable to the departing generation customer) to the other users of the utility's transmission system. We believe that this negative aspect of a broad-based approach—its violation of the cost causation principle—is too great a price to pay for allowing a departing generation customer to realize power cost savings as early as possible.

Thus, we recognize that under direct assignment, it is possible that some customers may not be able to afford to leave as soon as they would like. This in turn could mean that lower cost suppliers would not be able to make sales to those customers as soon as they would like. However, this would occur only during a transition period, and it would ensure that, consistent with strict cost causation principles, the burden of these transition costs is not unfairly spread to other customers. Once the existing uneconomic assets and contracts are behind us, all wholesale customers will be better able to shop for power and reap the long-term benefits of competitive supply markets.

Although this direct assignment approach is different from the approach taken in the natural gas industry, we believe that the difference is justified. The transition of the electric industry to an open transmission access, competitive industry (including our proposal to allow an opportunity for extra-contractual recovery of stranded costs associated with a discrete set of wholesale requirements contracts) is different in a number of respects from the natural gas industry's transition to open access transportation service by interstate natural gas pipelines. The gas industry underwent a long period of open access transition, starting with Order No. 436 in 1985 and culminating with Order No. 636 in 1992. In the gas context, prior to addressing potential stranded costs, the Commission in Order No. 436 allowed customers receiving bundled gas sales and transportation service from a pipeline the option to convert to transportation-only service, or to reduce their contract demand for gas service, before the termination of their contracts with the pipeline.[633] As a result, most of the former bundled customers of the pipeline had already departed the pipeline's sales service before the Commission addressed the recovery of take-or-pay costs in Order Nos. 500 and 528. In addition, by the time that the Commission addressed the remaining transition costs in Order No. 636, the commodity or wellhead natural gas market was already competitive and the majority of gas was already being sold on an unbundled basis.

Thus, changes in the natural gas industry had progressed to such a point (*i.e.*, the departure of customers from bundled sales) that it was not possible for the Commission to use a strict cost causation approach. We noted in the Supplemental Stranded Cost NOPR that

> Many natural gas customers had already left their historical pipeline suppliers' systems. Others had converted from sales and transportation customers to transportation-only customers. Others were in a transition stage having had opportunities to lower their contract demands or otherwise become partial service customers. Significant take-or-pay and other costs had accumulated.[634]

Under those circumstances, the Commission determined that it was appropriate to spread the majority of the remaining transition costs associated with take-or-pay and other supply contracts to all customers (both existing and new) using the interstate natural gas transportation system. Moreover, because of the changes in contractual relationships that had already occurred among pipelines and their customers, it was no longer possible for the Commission to follow a strict cost causation approach to recovering take-or-pay costs. The Commission-prescribed remedy for the recovery of transition costs in the natural gas industry thus was tailored to fit the needs of that industry given the stage of development at the time.

However, such a broad-based approach to recovery of natural gas transition costs was an *exception* to the

[631] To counteract this potential disadvantage, we have provided procedures in this Rule, including a formula that the utility is to use to calculate a departing generation customer's stranded cost obligation, that allow a customer considering switching power suppliers to request a stranded cost determination from the utility at any time before the expiration of the customer's wholesale requirements contract. *See* Section IV.J.9.

[632] In addition, because the customer would already know its stranded cost transmission surcharge, it presumably would have some certainty as to the costs of shopping for power. However, the stranded cost surcharge in its transmission rates subsequently may be adjusted upward if the utility providing transmission becomes eligible to recover retail-turned-wholesale stranded costs. Also, if the broad-based stranded cost surcharge is adjusted on an as-realized basis, the potential departing generation customer's surcharge may increase as a result of other customers leaving the utility's system.

[633] As discussed in Section IV.A.5, we are not providing for a similar conversion right in this Rule.

[634] FERC Stats. & Regs. ¶32,514 at 33,108.

time-honored principle that rates should reflect cost causation, and because of this it was necessary for the Commission to justify its departure from that principle. As the court said in *K N Energy* v. *FERC,*[635] ''[i]t has been this Commission's long standing policy that rates must be cost supported. Properly designed rates should produce revenues from each class of customers *which match, as closely as practicable, the costs to serve each class or individual customer.*'' In that case, the court found the Commission's departure from cost-causation justified ''given the unusual circumstances surrounding the take-or-pay problem, and the limited nature—both in time and scope—of the Commission's departure from the cost-causation principle.''[636] It continues to be Commission policy to follow the cost-causation principle to the extent possible.

The factors described above are not present in the electric industry. At this time, the vast majority of customers remain on their bundled suppliers' systems and generation is not yet fully competitive. Because the situation facing the electric industry today is different from that which the natural gas industry faced, the Commission must tailor its approach differently. In the case of the electric industry today, we have the opportunity to address the stranded cost recovery issue up front, before customers leave their suppliers' systems. We thus are able to use the cost causation approach that has been fundamental to our regulation since 1935.[637]

The Commission disagrees with commenters' arguments that we cannot impose an exit fee to recover stranded costs because we did not do so in the gas context. As discussed in Section IV.J.9, this Rule establishes procedures for providing a potential departing generation customer advance notice (*before* it leaves its existing supplier) of the stranded cost charge (whether it is to be paid as an exit fee or a transmission surcharge) that will be applied if the customer decides to buy power elsewhere. In the natural gas context, in contrast, the Commission has prohibited pipelines from developing and charging an ''exit fee'' *after* a customer had implemented its gas purchase decision, noting that otherwise, the customer would not know in advance the full cost consequences of its nomination decision.[638] The ''exit fee'' that the Commission rejected in *El Paso Natural Gas Company*[639] is also factually distinguishable from the ''exit fee'' discussed in this rule. In that case, the Commission rejected a pipeline's attempt post-restructuring to impose an ''exit fee'' on firm transportation-only customers (that were converted sales customers) who in the future elect either to terminate their firm transportation service upon expiration of the service agreement, or to reduce their firm transportation services level by more than 10 percent pursuant to an existing contractual reduction right. Such a scenario is quite different from the limited opportunity for stranded cost recovery provided in this Rule, which is based on a utility's reasonable expectation of continuing generation service to a bundled (sales and transmission) requirements customer.

We also will decline to require a utility seeking stranded cost recovery to shoulder a portion of its stranded costs. Such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[640] Although the Commission allowed such an approach with regard to a natural gas pipeline's take-or-pay costs,[641] we did so only as an extraordinary measure given the nature of the take-or-pay problem and the prevailing environment at that time. We returned to traditional principles when, in issuing Order No. 636, we authorized pipelines to recover all of their prudently incurred gas supply realignment costs (the costs pipelines incur in realigning, renegotiating, or terminating their portfolio of gas supply contracts to adjust to their sales customers' decisions to exercise their unilateral right under the rule to reduce or end their commodity purchase obligations to the pipelines).[642] In the case of the open access transmission required by this Rule, we believe that a utility is entitled to an opportunity to recover all legitimate, prudent and verifiable costs incurred by the utility when the availability of open access transmission enables a requirements customer to reach a new generation supplier.

Although the alternatives of either spreading the stranded costs to all transmission users or requiring the utility shareholders to share the costs with departing customers might enable a wholesale customer to leave sooner than would the direct assignment approach, the departing customer would be able to do so only at the expense of others who had no responsibility for causing the legitimate, prudent and verifiable costs to be incurred. Although we departed from strict cost causation principles in the gas context and required a broad spreading of the costs given the particular circumstances presented by the gas industry's transition to open access, we ultimately returned to the more traditional approach of allowing utilities to recover all of their prudently incurred transition costs in Order No. 636. At this juncture in the evolution of competition in the electric industry we need not make such a departure from cost causation principles; utilities can identify and seek to charge the customers who caused the costs to be incurred in the first place, before those customers leave the utility's generation system. Accordingly, we believe that a broader spreading of the costs to entities who are not responsible for the incurrence of

[635] 968 F.2d 1295, 1300–01 (D.C. Cir. 1992) (quoting Alabama Electric Cooperative, Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982) (emphasis in original).

[636] *Id.* at 1301. *See also* Public Utilities Commission of State of California v. FERC, 988 F.2d 154, 169 (D.C. Cir. 1993).

[637] Moreover, as we explained in the Supplemental Stranded Cost NOPR, the shifting of generation costs to transmission rates does not violate Commission policy where, as here, the customer that caused the costs to be incurred and stranded will continue to pay those costs. As we indicated, the only difference is that in some instances the customer will pay the costs through an adder to its transmission rate instead of through a generation rate. *See* FERC Stats. & Regs. ¶32,514 at 33,108 n.269.

[638] *See, e.g.,* Transwestern Pipeline Company, 43 FERC ¶61,240 at 61,654, *order on rehearing,* 44 FERC ¶61,164 at 61,536 (1988), *relevant petitions for review dismissed as moot,* Transwestern Pipeline Company v. FERC, 897 F.2d 570, 575–76 (D.C. Cir. 1990); El Paso Natural Gas Company, 47 FERC ¶61,108 at 61,314 (1989).

[639] 72 FERC ¶61,083 (1995). Further, VT DPS misinterprets the Commission's reference to the NOPR in that case. The Commission did not treat a notice of termination provision in El Paso's contract as a conclusive presumption that El Paso had no reasonable expectation of continuing to serve certain customers, as VT DPS contends. The Commission merely stated that ''[e]ven if the rules proposed in [the Supplemental Stranded Cost] NOPR were applied here, El Paso would have difficulty justifying the exit fee proposed in light of the existence of the notice of termination provision in the contract.'' 72 FERC at 61,441.

[640] *See, e.g.,* Maryland v. Louisiana, 451 U.S. 725, 748 (1981); Office of Consumers' Counsel v. FERC, 914 F.2d 292 (D.C. 1990); National Fuel Gas Supply Corporation v. FERC, 900 F.2d 340, 342, 347–51 (D.C. Cir. 1990).

[641] In Order No. 500, the Commission provided that if pipelines absorbed from 25 to 50 percent of their take-or-pay settlement costs, they could recover an equal amount from their firm sales customers in the form of fixed charges. Any balance could be recovered in the form of a commodity rate surcharge or a volumetric surcharge on total pipeline throughput. Order No. 500, FERC Stats. & Regs. ¶30,761 at 30,787 (1987). *See also* Order No. 528, 53 FERC ¶61,163 at 61,597 (1990). Moreover, we offered pipelines an important *quid pro quo* for absorbing take-or-pay costs under Order Nos. 500 and 528—a special presumption that they had been prudent in incurring their take-or-pay liabilities.

[642] Order No. 636, FERC Stats. & Regs. ¶30,939 at 30,461.

the stranded costs would not be equitable.

4. Recovery of Stranded Costs Associated With New Wholesale Requirements Contracts

In the Supplemental Stranded Cost NOPR, the Commission preliminarily concluded that future wholesale contracts must explicitly address the obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. We stated that utilities will be allowed stranded cost recovery associated with ''new'' wholesale requirements contracts (executed after July 11, 1994) only if *explicit* stranded cost provisions are contained in the contract. We indicated that recovery of wholesale stranded costs associated with any such new contract will not be allowed unless such recovery is provided for in the contract.[643] We also stated that a contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a ''new'' contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.[644]

We also stated that it is not appropriate to impose on a wholesale requirements supplier a regulatory obligation to continue to serve its existing requirements customer beyond the end of the contract term. We proposed to retain the § 35.15 prior notice of termination filing requirement only for: (i) All contracts required to be filed under sections 205 and 206 of the FPA that were executed before the effective date of the Final Rule pro forma tariffs; and (ii) any unexecuted contracts that were filed before the effective date of the Final Rule pro forma tariffs. With regard to any power sales contract executed on or after that date, we proposed to no longer require prior notice of termination under § 35.15, but to require (for administrative reasons) written notification of the termination of such contract within 30 days after termination takes place. We requested comments on whether this proposal should also be applied to transmission contracts.[645]

Comments

Numerous commenters support our preliminary conclusion that new wholesale requirements contracts should explicitly address the obligations of the seller and buyer and that it is not appropriate to impose on wholesale requirements suppliers a regulatory obligation to continue to serve their existing requirements customers beyond the end of the contract term.[646] However, Arkansas Cities expresses concern that this could undermine obligations to serve that have been included in certain contracts with utilities. It asks the Commission to state that, unless a utility has undertaken an obligation to serve via contract, there is no obligation to serve beyond the contract term. Arkansas Cities asks the Commission to clarify that contracts establishing an obligation to serve will be enforced.

Several other commenters argue that if a wholesale customer elects to switch suppliers, the previous supplier should be under no obligation to take the customer back onto its system at embedded cost rates.[647] Sierra asks the Commission to endorse a host utility's ability to insist on protective contract provisions before reestablishing service, including a predetermined period (such as five years—a commonly-used planning period) before the customer could seek to leave the system again.

A number of commenters support the Commission's proposal to eliminate the prior notice of termination requirement for power sales contracts executed after the date on which the final rule pro forma tariffs become effective.[648] Southern states that, because of the opportunities for power purchasers that will exist after the proposed rules take effect, the Commission also should eliminate § 35.15 as it applies to old contracts.

Several commenters support eliminating the § 35.15 filing requirement for transmission contracts as well.[649] This change is needed, some assert, to provide certainty in commercial arrangements in the more competitive environment and as a matter of fairness. CSW suggests that all § 35.15 filing requirements for existing contracts (wholesale and transmission contracts) be phased out over three years and that only contracts that expire within three years after the final rule should be subject to the requirement to file a notice of termination.

Nevertheless, several other commenters oppose the Commission's proposal to no longer require prior notice of termination for power sales contracts executed on or after the effective date of the generic tariffs.[650] TDU Systems opposes elimination of § 35.15 as tantamount to a finding that termination of all contracts is just and reasonable. TDU Systems and NRECA submit that the market power exercised by supplying utilities will not disappear the instant the rule becomes final and that it may be possible for a utility to exercise monopoly power even with regard to ''new'' contracts. They propose that if the Commission nevertheless decides to allow contract termination under § 35.15, the Commission should require a public utility to pay ''stranded benefit'' costs to former wholesale power customers if the customers show that they had a reasonable expectation that the power sales would continue past the end of the agreement at the prior rate.

Several commenters also oppose eliminating the § 35.15 filing requirement for transmission contracts.[651] FL Com asserts that because the Commission has imposed an obligation to serve for transmission service, § 35.15 should be retained for new and existing transmission contracts.

Commission Conclusion

We reaffirm our preliminary determination that future wholesale requirements contracts should explicitly address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. As we indicated in the Supplemental Stranded Cost NOPR, now that utilities have been placed on explicit notice that the risk of losing customers through increased wholesale competition must be addressed through contractual means only, they must address stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so.

We accordingly will allow recovery of wholesale stranded costs associated with any new requirements contract

[643] FERC Stats. & Regs. ¶ 32,514 at 33,110.

[644] *Id.* at 33,118.

[645] *Id.* and nn. 273, 274.

[646] *E.g.,* PA Com, FL Com, PSNM, Southern, NC Com, Duke, Public Service Co of CO, SoCal Edison, PacifiCorp, Carolina P&L, NYSEG.

[647] *E.g.,* Sunflower, Sierra, Public Service Co of CO, Duke.

[648] *E.g.,* EEI, NYSEG, Southern, PA Com, SoCal Edison, Pacificorp, El Paso.

[649] *E.g.,* EEI, Public Service Co of CO, PA Com, Entergy, Florida Power Corp.

[650] *E.g.,* TDU Systems, NRECA, TAPS, Redding, Southwest TDU Group. VT DPS sees no urgent need for elimination of the § 35.15 requirement or for automatic termination of sales service under a wholesale contract of more than three years duration. However, it supports pregranted authorization of service termination upon expiration of sales contracts with terms of less than three years. Among other things, it submits that the pregranted authority to terminate short-term service would relieve the utility of a planning uncertainty and allow it to maximize use of uncommitted transmission capacity.

[651] TAPS, TDU Systems, FL Com, MMWEC.

(executed after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. By ''explicit stranded cost provision'' (for contracts executed after July 11, 1994) we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate. For purposes of requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register, however, we clarify that a provision that specifically reserved the right to seek stranded cost recovery consistent with what the Commission permits in this Rule (without identifying the specific amount of stranded cost liability of the customer(s) and calculation method) nevertheless will be deemed an ''explicit stranded cost provision.'' However, a provision in a requirements contract executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that merely postpones the issue of stranded cost recovery without specifically providing for such recovery will *not* be considered an ''explicit stranded cost provision.'' After the date on which this Final Rule is published in the Federal Register, a provision must identify the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate in order to constitute an ''explicit stranded cost provision.''

We reaffirm that a requirements contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a ''new'' requirements contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.

We also reaffirm our preliminary determination not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term. The only exception to this would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the supplying utility reasonably expected to continue serving the customer. In such a case, the supplying utility will be obligated to offer continuing service to the requirements customer for the period the utility reasonably expected to continue serving the customer.

A requirements customer will be responsible for planning to meet its power needs beyond the end of the contract term by either building its own generation, signing a new power sales contract with its existing supplier, or contracting with new suppliers in conjunction with obtaining transmission service under its existing supplier's open access transmission tariff or another utility's transmission system. In so holding, it is not our intent to undermine any obligations specifically contained in a contract. Thus, if a contract explicitly establishes an obligation to serve beyond the end of the contract term, such a contractually-imposed obligation to serve (as distinguished from a regulatory obligation to serve) would be enforceable as a term of the contract. If a wholesale customer that switches suppliers later seeks to reestablish service with its former supplier, it will be up to the parties to negotiate their respective obligations.

We also reaffirm our preliminary determination to no longer require prior notice of termination under § 35.15 for any power sales contract executed on or after the effective date of the Final Rule pro forma tariff (but to require written notification of the termination of such contract within 30 days after termination takes places). This determination goes hand-in-hand with our determination (discussed above) not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term.[652] We clarify, however, that this decision applies only to a power sales contract that is to *terminate by its own terms* (such as on the contract's expiration date). We have revised § 35.15 accordingly. We will, however, continue to require prior notice of cancellation or termination for any power sales contract that is proposed to be cancelled or terminated for a reason other than by the contract's own terms (such as a self-help provision related to, for example, a billing dispute), regardless of when the contract was executed. We also will continue to require prior notice of the proposed termination of any power sales contract executed before the effective date of the Final Rule pro forma tariff (even if the contract is to terminate by its own terms) as well as any unexecuted power sales contract that was filed before that date.

Further, we will retain the § 35.15 filing requirement for all transmission contracts. The reason for retaining the § 35.15 requirement for transmission contracts is that transmission will continue to be provided under conditions of potential market power, and the Commission must be assured that transmission owners are not exerting market power in termination of transmission contracts. In addition, this filing requirement will provide the customer an opportunity to notify the Commission if the termination terms are disputed or if the customer was not given adequate opportunity to exercise its limited right of first refusal under the Final Rule (*see* Section IV.A.5).

5. Recovery of Stranded Costs Associated With Existing Wholesale Requirements Contracts

In the Supplemental Stranded Cost NOPR, the Commission reaffirmed its proposal to permit the recovery of legitimate, prudent and verifiable stranded costs for a discrete set of ''existing'' wholesale requirements contracts (executed on or before July 11, 1994)—those that do not already contain exit fees or other explicit stranded cost provisions. We encouraged the parties to such contracts to renegotiate them to address stranded costs. In the case of existing contracts that already contain an exit fee or explicit stranded cost provision, however, we proposed to reject a unilateral stranded cost amendment; that is, we stated we would reject an amendment unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to renegotiate the contract.[653] In so doing, we proposed to drop the three year mandatory negotiation period suggested in the initial Stranded Cost NOPR.[654]

If an existing requirements contract does not contain an exit fee or other explicit stranded cost provision (and is not renegotiated to add such a provision), we proposed that before the expiration of the contract: (1) A public utility or its customer may file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility or transmitting utility may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

[652] Although several commenters have asked the Commission to retain the prior notice of termination filing requirement due to concern that a utility nevertheless may be able to exercise generation market power with regard to a ''new'' wholesale requirements contract, we do not believe that retention of that provision is necessary to address these commenters' concerns. Instead, any party claiming to be aggrieved by a utility's alleged abuse of generation market power under a wholesale requirements contract can file a complaint with the Commission under section 206 of the FPA.

[653] FERC Stats. & Regs. ¶ 32,514 at 33,113.

[654] We invited comments on this proposal. *Id.* at 33,115.

In the Supplemental Stranded Cost NOPR, we reaffirmed our proposal in the initial Stranded Cost NOPR that, even if the contract contains an explicit *Mobile-Sierra* [655] provision, it is in the public interest to permit public utilities to seek unilateral amendments to add stranded cost provisions if the contracts do not in essence forbid such recovery by containing exit fees or other explicit stranded cost provisions.[656] Under these circumstances, if neither of the parties seeks and obtains acceptance or approval of a stranded cost amendment, we propose to permit the public utility to seek recovery of stranded costs through its wholesale transmission rates.

We also proposed procedures for providing an existing wholesale requirements customer advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[657]

Comments

a. July 11, 1994 Cut-Off Date

A number of commenters ask the Commission to reconsider the July 11, 1994 cut-off date for distinguishing between ''existing'' and ''new'' requirements contracts. Some commenters [658] support October 24, 1992 (the date of passage of the Energy Policy Act) as the cut-off date on the basis that anyone entering into a wholesale requirements contract after that date should have recognized the greatly increased possibility of the customer terminating or not renewing the contract.

Other commenters [659] support a later date for defining ''new'' requirements contracts, such as the date on which the final rule open access tariffs become effective. Utilities For Improved Transition argues that the Commission cannot retroactively adopt the July 11, 1994 cut-off date, but must wait until the final rule is issued before setting the date after which requirements contracts must contain stranded cost provisions in order for stranded cost recovery to be allowed.

Commenters representing electric cooperatives also oppose the July 11, 1994 cut-off date.[660] They contend that RUS borrowers were not free to negotiate stranded cost amendments to wholesale power contracts as soon as the Commission warned them to do so because their wholesale power contracts are mandated both as to form and substance by the RUS.[661]

PA Munis asks the Commission to treat certain contracts that were executed before July 11, 1994 (but not approved by the Commission until after that date) as ''new'' contracts. PA Munis argues that the utility, after issuance of the initial NOPR, could have withdrawn its filing of the contract and sought to negotiate an exit fee at that time. It submits that the utility's failure to do so would justify a finding by the Commission that contracts *approved* after July 11, 1994 be treated similarly to contracts executed after that date.

b. Stranded Cost Recovery for Existing Requirements Contracts

A number of commenters express support for the Commission's proposal to permit modification of existing requirements contracts that do not already contain exit fees or other explicit stranded cost provisions.[662] NEPCO states its interpretation that the NOPR does not consider notice provisions to be ''explicit stranded cost provisions;'' it argues that the presence of a notice provision in a contract, while bearing on the supplier's ability to demonstrate the duration of its reasonable expectation of continued service, should not foreclose the amendment of a wholesale contract to add an exit fee or similar payment provision. Several other commenters ask the Commission to clarify that contracts that contain notice provisions and that preclude recovery for termination or reduction of service (but that do not necessarily use the terms ''exit fee'' or ''stranded cost''), or that expressly provide that stranded costs shall not be charged, cannot be reopened for a stranded cost claim.[663]

A number of other commenters oppose the Commission's proposal to permit amendment of wholesale requirements contracts that do not address stranded cost recovery, for reasons previously raised in this proceeding.[664] They argue, among other things, that contracts should stand on their own. RUS asserts that the integrity of its Federal loan program is to a large extent predicated on honoring the long-term requirements wholesale power contracts between G&Ts and their distribution members.

Several commenters also challenge the Commission's proposed determination that it is in the public interest to permit utilities to seek unilateral amendments to add stranded cost provisions to requirements contracts. These commenters argue that the NOPR's assumptions concerning the financial stability of public utilities are unsupported and thus do not meet the burden of proof required for the public interest finding under the *Mobile-Sierra* doctrine. They urge the Commission to require a utility-specific finding of imminent financial jeopardy before overriding a *Mobile-Sierra* contract.[665]

ELCON argues that the recent *Northeast Utilities Service Company* v. *FERC* [666] case reaffirms the traditional high threshold for overriding *Mobile-Sierra* clauses in the ''classic *Mobile-Sierra* situation'' in which one of the parties seeks modification of a contract that has already been reviewed and approved by the Commission. It submits that a utility seeking to add a stranded cost provision to an existing contract would fall within the ''classic situation.'' ELCON also argues that the First Circuit strongly implied that to satisfy *Mobile-Sierra*, the Commission must identify specifically those aspects of a contract that are contrary to the public interest and why. On this basis, ELCON argues that the case supports its position that a utility-specific finding of imminent financial jeopardy is necessary to override an existing *Mobile-Sierra* contract.[667]

[655] *See* United Gas Pipeline Company v. Mobile Gas Service Corporation, 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956).

[656] FERC Stats. & Regs. ¶ 32,514 at 33,113–14. We noted that under the *Mobile-Sierra* doctrine, a customer may waive its right to challenge the contract and/or the utility may waive its right to make unilateral rate changes. However, the parties may not waive the indefeasible right of the Commission to alter rates that are contrary to the public interest. *Id.* at 33,111.

[657] *Id.* at 33,114–15.

[658] *E.g.,* ELCON, TAPS, Alcoa, Utilicorp.

[659] *E.g.,* Utilities For Improved Transition, Atlantic City.

[660] *E.g.,* Basin, Tri-County EC, NW Iowa Cooperative, Baker EC, Big Horn EC, Black Hills EC, Bon Homme Yankton EC, Carbon Power, Central EC, Douglas EC, East River EC, Ida County REC, James Valley EC, Lincoln-Union EC, McKenzie EC, North Dakota RECs, Oahe EC, Oliver-Mercer EC, Panhandle Coop, Rushmore EC, San Luis Valley EC, Slope EC, Spink EC, Turner-Hutchinson EC, Traverse EC, Union County EC, West River EC, Whetstone Valley EC, Woodbury County REC, Yellowstone Valley EC.

[661] Basin indicates that all such contracts for the sale of more than 1,000 kW and any amendments thereto must be specifically approved by the RUS.

[662] *E.g.,* EEI, PSNM, AEP, Consumers Power. Consumers Power suggests that the language of proposed § 35.26(c)(1)(iv) be modified to recite the Commission's public interest finding.

[663] *E.g.,* Concord, Chugach, ME Consumer-Owned Utilities.

[664] *E.g.,* Utilicorp, AMP-Ohio, Environmental Action, DE Muni, Arkansas Cities, Direct Service Industries, PA Munis, ABATE, APPA.

[665] *See, e.g.,* American Forest & Paper, VT DPS, PA Munis, ABATE, ELCON, APPA, Environmental Action.

[666] 55 F.3d 686 (1st Cir. 1995) (*Northeast Utilities*).

[667] PA Munis argues that *Northeast Utilities* provides no support for the Commission's proposed *Mobile-Sierra* finding because *Northeast Utilities* involved the effect of disputed contractual terms on

Some commenters argue that if utilities are to be granted industry-wide *Mobile-Sierra* relief, then the Commission should give wholesale customers the reciprocal right to convert their wholesale power contracts to transmission-only service.[668] However, EEI contends that the Commission is barred by section 211(c)(2) of the FPA from ordering wheeling where a customer is taking service under a contract or under a rate tariff on file with the Commission.

Several commenters ask the Commission to require renegotiation of the notice and/or term of all existing contracts with long lead-time cancellation provisions in order to allow all wholesale customers access to the market at the same time.[669] They submit that customers with short notice provisions will be the first to enjoy the benefits of open access and will have an effective ''first right of refusal'' of the most economical transmission paths and low cost suppliers, putting customers with long lead-time cancellations at a competitive disadvantage.

c. Transition Period

A number of commenters support the Commission's proposal not to mandate a three-year time limit for renegotiation of existing wholesale requirements contracts. They note that existing contracts have unique characteristics and complexities that affect the time required to renegotiate the contract bilaterally, to file a unilateral amendment with the Commission, or to file for stranded cost recovery through transmission rates.[670]

On the other hand, some commenters object that the proposal to replace the previously proposed three-year window with an opportunity to raise stranded cost claims throughout the existing contract term creates a virtually unlimited transition period.[671] For example, ELCON asserts that because the NOPR would allow utilities to seek amendment of an existing contract any time prior to its expiration, stranded cost issues could extend through the life of existing facilities (30 years or more). Portland suggests that the Commission set a schedule now for proceedings to determine transmission costs and stranded costs for each utility with wholesale requirements customers.

Commenters propose various limits to the period within which stranded cost recovery could be raised, such as: (i) Three to five years;[672] (ii) the lesser of three years from the effective date of the final rule or the remaining term of the contract;[673] (iii) one year from the effective date of the final rule;[674] and (iv) December 31, 1998 (20 years after PURPA).[675]

Commission Conclusion

a. July 11, 1994 Contract Cut-Off Date

We reaffirm our proposal to permit the recovery of legitimate, prudent and verifiable stranded costs for ''existing'' wholesale requirements contracts (executed on or before July 11, 1994) that do not already contain exit fees or other explicit stranded cost provisions. We believe that July 11, 1994—the date on which the initial Stranded Cost NOPR was published and, thus, on which the industry was put on notice of the proposal to disallow prospectively extra-contractual recovery of stranded costs—is the appropriate date for distinguishing ''existing'' requirements contracts from ''new'' requirements contracts. Because all parties were put on notice in the initial Stranded Cost NOPR that July 11, 1994 would be the operable date for the ''existing''/''new'' contract distinction, utilities that executed requirements contracts after that date could have had no reasonable expectation that they would be permitted to recover any costs extra-contractually.

Moreover, because the costs at issue are extra-contractual costs, the Commission's notice to all parties that contracts executed after July 11, 1994 will be enforced by their terms as far as stranded cost recovery is concerned does not constitute ''retroactive rulemaking.'' Contrary to UFIT's contention, the Commission is not ''requir[ing]'' utilities to include stranded cost recovery provisions in all contracts executed after July 11, 1994.[676] The Commission has merely put all parties on notice that the opportunity for extra-contractual stranded cost recovery (which will be allowed on a prospective basis upon the effective date of the Rule) will not be available for any requirements contracts executed after July 11, 1994. The parties to requirements contracts executed after July 11, 1994 have been free to provide for stranded cost recovery in the contract, or not.[677] The point is that, for requirements contracts executed after the cut-off date, stranded cost recovery will be governed solely by the terms of the contract.

b. Stranded Cost Recovery for Existing Requirements Contracts

We reaffirm that we will permit utilities to seek recovery of stranded costs for a limited set of existing wholesale requirements contracts, namely, those that do not already contain exit fees or other explicit stranded cost provisions.[678] If an existing requirements contract includes an explicit provision for payment of stranded costs or an exit fee, we will assume that the parties intended the contract to cover the contingency of the buyer leaving the system. We will reject a stranded cost amendment to such a contract, unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to a new stranded cost provision. Similarly, we will reject a stranded cost amendment to an existing requirements contract if the contract prohibits stranded cost recovery (or precludes recovery for termination or reduction of service) or

third parties, not the alleged financial effect on the utility. It argues that the court found that the Commission had adequately explained how the disputed contractual terms may harm third parties to the contract (which PA Munis says the Commission has failed to do here). PA Munis also submits that the court went out of its way to emphasize the narrow scope of its order affirming the Commission.

[668] *E.g.,* ELCON, CCEM, VT DPS, OK Com, TDU Systems, LG&E, ABATE, Portland, Utilicorp, TAPS.

[669] *E.g.,* Knoxville, Memphis.

[670] *E.g.,* EEI, Florida Power Corp, PA Com, WP&L, Consumers Power, FL Com, TVA, SoCal Edison, Texas Utilities.

[671] *E.g.,* TAPS, TDU Systems, DOD, ELCON, APPA.

[672] *E.g.,* Sierra, Central Illinois Light, NY Energy Buyers, American Forest & Paper, WEPCO, EGA. Education proposes either a transition period that ends five years after the effective date of the final rule or a phase-out of the utility's authority to recover stranded costs from departing customers by gradually reducing (for instance, over a ten year period from the date of the final rule) the percentage of stranded costs that the utility could recover.

[673] *E.g.,* TAPS, Missouri Joint Commission.

[674] *E.g.,* TDU Systems.

[675] *E.g.,* DOD, ABATE.

[676] See UFIT Initial Comments at 34. Moreover, the cases that UFIT cites, in which the Commission rejected parties' efforts to devise rates based on methods or formulas contained in proposed rules, are inapposite. By establishing the July 11, 1994 cutoff date, the Commission is not ''fix(ing) rates under section 206'' or otherwise making ''a Section 206 'determination,' '' as UFIT suggests. *Id.* at 35, 36. The Commission has not proposed a change in the way that utilities compute their rates; it has simply put all parties on notice of the limited nature and opportunity for extra-contractual stranded cost recovery.

[677] In response to the commenters representing electric cooperatives that object to the July 11, 1994 cut-off date, we do not believe that the requirement that RUS borrowers obtain RUS approval of their contracts necessarily prevents such borrowers from addressing stranded cost recovery in contracts executed after July 11, 1994.

[678] We confirm that a notice of termination provision by itself (that is, one that does not also provide for or preclude recovery of stranded costs by the seller upon termination of the contract) is not an ''explicit'' stranded cost provision; however, as discussed in Section IV.J.8, the presence of a notice provision creates a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer.

prohibits renegotiation of an existing stranded cost or exit fee provision, unless the parties to the contract mutually agree to a new stranded cost provision.[679]

We reaffirm our desire that utilities attempt to renegotiate with their customers existing requirements contracts that do not contain exit fees or other explicit stranded cost provisions. If the parties negotiate a stranded cost provision and the seller is A public utility, the utility must file the provision with the Commission as an amendment to the existing requirements contract.

If an existing requirements contract does not contain an exit fee or other explicit stranded cost provision (and is not renegotiated to add such a provision), before the expiration of the contract: (1) a public utility or its customer may file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility in a section 205 proceeding, or a transmitting utility in a section 211 proceeding, may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

We thus reaffirm that if an existing requirements contract is not renegotiated, and the contract permits the seller and/or buyer to seek an amendment to the contract, the authorized party may seek an amendment to add a stranded cost provision. We also adopt our preliminary finding that, even if an existing requirements contract contains an explicit *Mobile-Sierra* provision, it is in the public interest to permit the public utility to seek a unilateral amendment to add stranded cost provisions if the contract does not already contain exit fees or other explicit stranded cost provisions. In the initial Stranded Cost NOPR, we identified two ways in which a failure to permit public utilities to address stranded costs could harm third parties, and thereby harm the public interest:

First, the inability to seek recovery of stranded costs could impair the financial ability of a utility to continue to provide reliable service. This will depend on the magnitude of stranded costs and the prospect or lack thereof for recovering such costs from ratepayers. The prospect of not recovering from ratepayers significant amounts of stranded costs could seriously erode a utility's access to capital markets, or could drive the utility's cost of capital to unprecedented levels. This high cost of capital could precipitate other customers leaving the system which, in turn, could cause others to leave. Such a spiral could be difficult to stop once begun. Second, if some customers are permitted to leave their suppliers without paying for stranded costs, this may cause an excessive burden on the remaining customers who, for whatever reason, cannot leave and therefore may have to bear those costs.[680]

The financial community commenters confirm our views in this regard. As they note, a utility's access to financial markets is essential to the continued provision of safe and reliable electric service to customers. However, the prospect of a utility not recovering stranded costs could erode a utility's ability to attract capital and thus imperil its continued financial stability.[681] As these and other commenters agree, the recovery of stranded costs is critical to the successful transition to more competitive markets.

Moreover, our determination that it is in the public interest to give public utilities a limited opportunity to propose contract changes unilaterally to address stranded costs if their contracts do not already explicitly do so satisfies the public interest standard of the *Mobile-Sierra* doctrine as recently interpreted by the *Northeast Utilities* court. In that case, the court affirmed an order of the Commission on remand modifying a contract under the *Mobile-Sierra* public interest standard.[682] As the court explained, the *Mobile-Sierra* doctrine ''represents the Supreme Court's attempt to strike a balance between private contractual rights and the regulatory power to modify contracts when necessary to protect the public interest.'' [683] The court noted that when the Commission is considering whether a contract rate is too low, protective action by the Commission in the public interest is justified ''where the rate might impair the financial ability of the utility to continue to supply electricity, force electricity consumers to bear an excessive burden, or be unduly discriminatory.'' [684]

The court also explained that ''the most attractive case for affording additional protection [under the public interest standard], despite the presence of a contract, is where the protection is intended to safeguard the interests of third parties * * *.' '' [685] It stated that the *Mobile-Sierra* doctrine allows the Commission to modify the terms of a private contract ''when third parties are threatened by possible 'undu[e] discrimination' or the imposition of an 'excessive burden.' '' [686] The court found that the Commission had met the public interest standard by showing how the contract could harm *third parties*.[687]

Consistent with the holding in *Northeast Utilities*, and contrary to the positions of some commenters, we have demonstrated how ''*third parties* may ultimately bear the burden'' [688] if public utilities with *Mobile-Sierra* contracts are not given any opportunity to propose contract changes to address stranded costs. If the Commission fails to give a

[679] In the case of an existing wholesale requirements contract that does not contain an exit fee or other explicit stranded cost provision but does contain a notice provision, once a customer gives notice according to the terms of the contract that it will no longer purchase all or a part of its requirements from the selling utility, we would not allow the utility to amend the contract to add a stranded cost provision. However, in such a case, the utility could seek to recover stranded costs through its rates for transmission services to the customer. As discussed in Section IV.J.8, the utility would have to rebut the presumption that, based on the presence of the notice provision, it had no reasonable expectation of continuing to serve the customer.

[680] FERC Stats. & Regs. ¶ 32,507 at 32,870.

[681] *See* Utility Investors Analysts, Initial Comments at 2–3; Utility Shareholders, Initial Comments at 2–4.

[682] The court concluded that the Commission ''gave thoughtful consideration to the public interest.'' 55 F.3d at 693.

[683] *Id.* at 689.

[684] *Id.* at 690.

[685] *Id.* at 691, citing Northeast Utilities Service Company v. FERC, 993 F.2d 937, 961 (1st Cir. 1993).

[686] *Northeast Utilities*, 55 F.3d at 691. The court distinguished the facts of that case from other *Mobile-Sierra* cases. It noted that ''[t]he issue here is not whether one party to a rate contract filed with FERC can effect a rate change unilaterally, but the standard to be used by FERC in examining electric power contracts filed with it.'' *Id.* at 690–91. It also noted that the contract provisions under review were not low-rate issues in the context of *Mobile* and *Sierra*. We recognize that whether a contract should be modified to add a stranded cost provision could be viewed as one party to a contract seeking to effect a unilateral rate change, or as a low-rate issue (*i.e.*, whether the utility's rates would be insufficient without stranded cost recovery). However, parties are being permitted to make such unilateral filings only after a generic finding by the Commission that the public interest likely would be jeopardized if utilities are not permitted to make a case-specific showing that recovery should be allowed. We believe that *Northeast Utilities* provides valuable guidance concerning application of the public interest standard where, as here, a failure to allow limited contract modification may harm the public interest by harming third parties.

[687] The court found that the Commission had met the public interest standard ''by explaining how the disputed contractual terms may harm third parties to the contract. * * * For example, the Commission found the automatic rate-of-return-on-equity adjustment provision unacceptable because *third parties* may ultimately bear the burden of a rate component that does not reflect actual capital market conditions. Likewise, the 'blank check' given owners of the power plant to determine the decommissioning costs for themselves under New Hampshire law is impermissible because it may be cashed at the expense of non-parties to the contract.'' *Id.* at 692 (emphasis in original). The court rejected the argument that the public interest standard is ''practically insurmountable'' in all circumstances. It noted, among other things, ''that neither *Mobile* nor *Sierra* stated or intimated that the 'public interest' doctrine was 'practically insurmountable.' '' *Id.* at 691.

[688] *Id.* at 692 (emphasis in original).

public utility this opportunity, and the utility's financial ability to continue the provision of safe and reliable service is impaired, third parties (customers relying on the public utility for their electric service) will be placed at risk. Similarly, if the Commission fails to give a public utility the opportunity to directly assign costs to the customers on whose behalf they were incurred, and some of the utility's customers leave the utility's generation system for that of another supplier without paying such costs, third parties (the utility's remaining customers) will be harmed by having to bear the costs that were not incurred to serve them and that are stranded by the other customers' departures via open access transmission. Moreover, we believe that protective action in the public interest is particularly necessary where, as here, a utility's rates could become insufficient because of fundamental changes in the industry that largely result from legislative or regulatory changes that could not be anticipated.

Further, notwithstanding the arguments of some commenters supporting a case-by-case (as opposed to a generic) public interest finding, we believe it appropriate that our public interest finding be made on a generic basis given the fact that, by this Rule, we are requiring full open access that could significantly affect historical relationships among traditional utilities and their customers and the ability of utilities to recover prudently incurred costs. We also emphasize that we are not eliminating the need for case-by-case demonstrations that stranded cost recovery should be allowed. Our public interest finding is that utilities be permitted to *seek* extra-contractual recovery of stranded costs in certain defined circumstances. Utilities seeking recovery of stranded costs will have the burden, on a case-by-case basis, of showing they had a reasonable expectation of continuing to serve the departing generation customer.

In summary, we emphasize the limited nature of our *Mobile-Sierra* public interest finding. First, our holding applies only to wholesale requirements contracts executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision. Thus, we will not permit modification of any contract that addresses the stranded cost issue explicitly, unless the contract specifically permits such modifications. Instead, we are simply examining requirements contracts that do not clearly address the issue in the context of the traditional regulatory regime under which they were signed—a regulatory environment in which it was assumed as a matter of course that the great majority of requirements customers would stay with their original suppliers and that these suppliers had a concomitant obligation to plan to supply these customers' continuing needs.

Second, although we have decided on a generic basis that it is in the public interest to permit public utilities with *Mobile-Sierra* contracts to make unilateral filings, we are not automatically approving any amendment that a particular utility might file. As we stated in the initial Stranded Cost NOPR, if a public utility unilaterally files a proposed stranded cost amendment under either section 205 or 206 of the FPA, this does not necessarily mean that the Commission ultimately will find it appropriate to allow such amendment.[689] In addition, customers with *Mobile-Sierra* contracts that do not explicitly address stranded costs may also file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts. The Commission will analyze any proposed stranded cost amendment to a *Mobile-Sierra* contract, whether proposed by the utility or by its customer, based on the particular circumstances surrounding that contract. Thus, the case-by-case findings that some commenters seek will, in effect, be made when the Commission determines whether to approve a proposed stranded cost amendment to a particular contract.

As discussed in Section IV.A (Scope), the Commission has concluded that although current conditions in the wholesale power market do not warrant the generic modification of requirements contracts, nonetheless the modification of certain requirements contracts on a case-by-case basis may be appropriate. We have concluded further that, even if customers under such contracts are bound by so-called *Mobile-Sierra* clauses, they nonetheless ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

We have found that it would be against the public interest to permit a *Mobile-Sierra* clause in an existing wholesale requirements contract to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. For purposes of this finding, the Commission defines existing requirements contracts as contracts executed on or before July 11, 1994.[690] By operation of this finding, a party to a requirements contract containing a *Mobile-Sierra* clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

This finding complements the Commission's finding that, notwithstanding a *Mobile-Sierra* clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule. The Commission's complementary *Mobile-Sierra* findings are not mutually exclusive. Any contract modification approved under this section shall provide for the utility's recovery of any costs stranded consistent with the contract modification. The stranded costs must be prudently incurred, legitimate and verifiable. Further, the Commission has concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

The Commission believes that the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. Thus, if the selling public utility intends to claim stranded costs, it must present that claim in any section 206 proceeding brought by the customer to shorten or terminate the contract. Similarly, if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded costs. This will promote administrative efficiency and will permit the Commission to consider how the contracting parties' claims bear on one another.

689 FERC Stats. & Regs. ¶ 32,507 at 32,871.

690 This is consistent with the definition of existing requirements contracts we have used for purposes of stranded cost recovery.

The Commission does not take contract modification lightly. Whether a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, or a customer is seeking to shorten or eliminate the term of an existing contract, we believe that each have a heavy burden in demonstrating that the contract ought to be modified. Still, we believe that given the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants. The Commission expects that many of the arguments presented by buyers and sellers in such proceedings will be fact specific.

c. Transition Period

We reaffirm our proposal to allow a public utility or its customer to file a proposed stranded cost amendment, or to allow a public utility or transmitting utility to file a proposal to recover stranded costs through a departing generation customer's transmission rates, at any time prior to the expiration of the contract. There is no uniform time remaining on requirements contracts executed on or before July 11, 1994. Any limitation on the period in which parties could propose amendments covering stranded costs (*e.g.,* 3 years) would thus unequally affect market participants. Those with long terms remaining on their contracts could object that immediately addressing the issue would not be cost effective. For example, a utility with a long remaining term (*e.g.,* 20 years) might not even seek stranded cost recovery depending on the competitive value of its assets near the end of the contract term.[691] However, such a utility would invariably seek to preserve its option to seek stranded cost recovery if its failure to do so within a short period resulted in a waiver of its right to do so.

6. Recovery of Stranded Costs Caused by Retail-Turned-Wholesale Customers

In the Supplemental Stranded Cost NOPR, we stated that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers becoming wholesale customers who then obtain transmission under the open access tariffs.[692] We proposed that this Commission should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. We explained that if a retail customer becomes a legitimate wholesale customer (such as through municipalization), it becomes eligible to use the non-discriminatory open access tariffs:

> If costs are stranded as a result of this wholesale transmission access, we believe that these costs should be viewed as 'wholesale stranded costs.' But for the ability of the new wholesale entity to reach another generation supplier through the FERC-filed open access transmission tariff, such costs would not be stranded.[693]

We accordingly proposed to define ''wholesale stranded costs'' to include stranded costs resulting from unbundled transmission for newly-created wholesale customers and sought comments on this definition.

We proposed to require the same evidentiary demonstration for recovery as that required if recovery were sought from a wholesale requirements customer. We reaffirmed our proposal in the initial Stranded Cost NOPR that a utility will have to show that the stranded costs are not more than the net revenues that the retail-turned-wholesale customer would have contributed to the utility had it remained a retail customer of the utility, and that the utility has taken and will take reasonable steps to mitigate stranded costs. We further proposed to deduct any recovery that a state has permitted from departing retail-turned-wholesale customers from the legitimate stranded costs of which we will allow recovery. In addition, we proposed to apply the same procedures for obtaining an estimate of maximum stranded cost exposure without mitigation to retail customers contemplating becoming wholesale transmission customers as those proposed for wholesale customers.[694]

Comments

Some commenters contend that stranded costs that result when a retail customer becomes a wholesale customer should be left to the states as a matter of law and comity.[695] These commenters argue, among other things, that because the facilities used to provide retail service to these retail customers were subject to state jurisdiction and were included in retail rate base when the service was rendered, the state is the appropriate entity to determine the extent to which those customers should compensate the utility for the stranding of these costs. According to ELCON, ''(a) retail customer's new found access to the wholesale market does not provide FERC with authority over costs that originated with the local distribution function.'' [696]

Commenters assert that stranded costs resulting from the creation of new wholesale entities will occur as a result of state or local decisionmaking.[697] A number of commenters contend that in states where the state commission has control over municipalization, the Commission has no authority to provide for the recovery of stranded costs due to municipalization.[698] IL Com asserts that the Commission lacks authority over retail-turned-wholesale stranded costs, even in the absence of any explicit statutory authority for state commissions to address such costs. FL Com argues that the Commission should address the recovery of these stranded costs only upon petition from a state public utility commission.

According to some commenters, the availability of open access transmission tariffs does not convert the character of the costs of stranded generation that was built to serve retail customers from retail to wholesale.[699] CA Com argues that this reasoning could require the Commission to act as the primary forum for stranded costs resulting from retail wheeling if the Commission's jurisdiction over retail transmission is upheld. It argues that in such a case, there also would be a relationship between the Commission-jurisdictional transmission and stranded costs.

Some commenters also submit that the potential for retail customers to become wholesale customers has existed since the beginning of the industry and that utilities have had ample opportunity to adjust to this risk.[700] A number of commenters submit

[691] The value of its assets could vary over time as new technologies emerge, fuel costs fluctuate, or environmental requirements change.

[692] FERC Stats. & Regs. ¶ 32,514 at 33,127.

[693] *Id.* at 33,128.

[694] *Id.*

[695] *E.g.,* NARUC, ELCON, TAPS, NASUCA, N.Y. Mayors, NY Industrials, American Iron & Steel, Missouri Joint Commission, Omaha PPD, MI Com, NY Com, NJ BPU, VT DPS, OK Com, IN Com, UT Com, WA Com, Environmental Action, IN Industrials, LA DWP, Seattle, CAMU, Las Cruces, UT Industrials, Suffolk County, NM Industrials, CO Consumers Counsel.

[696] ELCON Comments, dated July 25, 1995, at 41.

[697] *E.g.,* MD Com, MI Com, LA DWP, Las Cruces. For example, MD Com states that while open access transmission may make municipalization more attractive, it ultimately is MD Com's approval that makes municipalization possible in Maryland.

[698] *E.g.,* MD Com, Las Cruces, Caparo, Coalition on Federal-State Issues, IN Com, MI Com, Iowa Board.

[699] *E.g.,* IL Com, CA Com, Midwest Commissions, CO Consumers Counsel.

[700] *E.g.,* LA DWP, Ohio Manufacturers, MMWEC, American Iron & Steel, UT Industrials, MI Com, NY Industrials, WA Com, Caparo.

that state commissions are in a better position than the Commission to address the recovery of costs that were incurred to serve retail customers and to take into consideration local concerns.[701]

NARUC recognizes that a ''practical regulatory gap may exist that prevents [state commission] consideration of recovery of * * * potentially stranded costs'' in certain instances ''such as municipalization and cooperatives, where retail customers become wholesale customers under a FERC-approved open access tariff, [and] costs of the utility which served the customer at retail may become stranded.'' [702] NARUC proposes that the affected states and the Commission collaboratively develop mechanisms (which may involve amendments to the FPA, state statutes, or both) to eliminate these regulatory gaps.

Some commenters object that the Commission's proposal to be the primary forum for recovery of stranded costs caused by retail-turned-wholesale customers would make municipalization more expensive and therefore would discourage municipalities from seeking alternative sources of electricity.[703] Some argue that different treatment of stranded costs between federal and state authorities may lead to forum-shopping as a primary determinant in the decision to municipalize.[704]

A number of commenters also suggest that the NOPR is inconsistent with prior Commission treatment of municipalization because the Commission has historically promoted franchise competition between municipalities and utilities and has never before suggested that utilities could ''penalize'' municipalization decisions through generation cost add-ons to transmission rates.[705] VT DPS states: ''By the Commission's logic, there would never have been an *Otter Tail* case. If Otter Tail could have made a stranded cost claim against the municipal utility Elbow Lake planned to create, Otter Tail would never have needed to refuse to wheel.'' [706]

Suffolk County states that the Commission already considered stranded costs in the context of retail-turned-wholesale customers in *United Illuminating Company*,[707] where the Commission required United Illuminating to remove a provision in its proposed transmission tariff that would have allowed it to recover stranded costs associated with former retail loads served by new municipal systems. Suffolk County states that the Commission made clear that stranded cost matters, including those caused by municipalization, properly would be raised before state regulatory authorities. It objects that the Open Access NOPR ignores this case. Suffolk County also submits that the Commission's adoption of the settlement approved by the Massachusetts DPU in the Massachusetts Bay Transportation Authority case should serve as an example of proper jurisdictional deference with respect to local issues.[708]

However, many other commenters support the Commission's proposal to be the primary forum for retail-turned-wholesale stranded costs.[709] These commenters submit, among other things, that the Commission's jurisdiction over such costs is clear.[710] Coalition for Economic Competition states that when a utility's costs are stranded through the availability of Commission-jurisdictional transmission service, the Commission must address those costs. It argues that commenters opposing the Commission's jurisdiction fail to analyze the Commission's duty to establish just and reasonable rates for Commission-jurisdictional transmission service.

A number of commenters support the Commission's proposal to address retail-turned-wholesale stranded costs on the basis that many state commissions either lack authority to address costs that are stranded because of expanding or newly-created municipal systems, or have failed to address such costs.[711] El Paso adds that any protection offered by state judicial condemnation proceedings does not obviate the need for the Commission's involvement in this issue, noting that condemnation awards may not provide full stranded investment recovery under the Commission's standards. In addition, El Paso suggests that municipalization may occur through means other than condemnation of the distribution systems of electric utilities, such as when a municipality constructs its own, duplicative distribution facilities.

Several commenters also indicate that by forthrightly addressing this issue, the Commission has removed a cloud of uncertainty that would have taken years to resolve through litigation.[712] El Paso states that the proposed rule is needed because utilities may be subject to stranded costs resulting from municipalization in two separate state jurisdictions.

In response to the argument that stranded costs are exclusively subject to state jurisdiction, SoCal Edison asserts that whether the costs are retail or wholesale is irrelevant because the issue is how and where these costs should be recovered. According to SoCal Edison, if the Commission finds that these costs are just and reasonable costs associated with providing open access transmission service, the Commission may allow utilities to recover them in Commission-regulated rates.

Coalition for Economic Competition notes that while utilities are aware of state laws allowing municipalities to condemn electric facilities and to form utilities, in recent decades, it has not happened on most systems. Moreover, it argues that merely being on notice that municipalization is a possibility does not relieve utilities of their state-imposed obligation to serve all

[701] *E.g.,* American Iron & Steel, MD Com, LA DWP, Suffolk County, MI Com, NJ BPU, N.Y. Mayors. NASUCA cites practical problems posed by the Commission's proposal to assume jurisdiction over stranded costs resulting from municipalization, such as how the Commission would transfer the revenues extracted from the retail-turned-wholesale customer to a non-wholesale, locally-franchised entity.

[702] NARUC Initial Comments at 18–19.

[703] *E.g.,* N.Y. Mayors, NIEP, Wing Group, VT DPS, NY Industrials, American Iron & Steel, Environmental Action, IN Industrials, Las Cruces, Caparo, UT Industrials.

[704] *E.g.,* IN Com.

[705] *E.g.,* VT DPS, American Iron & Steel. American Forest & Paper states that allowing stranded cost recovery in the event of municipalization would be inconsistent with the Commission's actions in the natural gas industry, where the Commission has encouraged competition at the retail level (through competitive bypass rather than franchise competition) and has not imposed transition charges or exit fees on converting customers.

[706] VT DPS Initial Comments at 49; *see also* American Iron & Steel, NY Industrials, Caparo.

[707] 63 FERC ¶ 61,212 (1993), *reh'g denied,* 64 FERC ¶ 61,087 (1993).

[708] *See* Massachusetts Electric Company, 68 FERC ¶ 61,101 (1994); Letter Order dated March 3, 1995, Docket No. ER94–129–000 (approving settlement).

[709] *E.g.,* EEI, PSE&G, Centerior, Com Ed, Consumers Power, Detroit Edison, Duke, El Paso, Entergy, LILCO, Minnesota Power, Montana-Dakota Utilities, NYSEG, PECO, PG&E, PSNM, Southern, Utilities For Improved Transition, Allegheny, OH Com, Utilicorp, PA Com, WI Com, Coalition for Economic Competition, Central Louisiana, United Illuminating, Utility Investors Analysts, Nuclear Energy Institute, Utility Shareholders.

[710] *E.g.,* Consumers Power, Coalition for Economic Competition, Utilities For Improved Transition.

[711] *E.g.,* Detroit Edison, Minnesota Power, El Paso, LILCO, Centerior, PG&E. PG&E urges a clarification in the rule so that the Commission would address retail-turned-wholesale stranded costs only if the state commission either lacks jurisdiction over municipal utilities, or, if it has jurisdiction, declines to address stranded costs. Where a state commission possesses jurisdiction over municipal entities and provides a utility with stranded cost recovery from former retail customers that have municipalized, PG&E proposes that such action should be final and not subject to Commission review. Other commenters, such as El Paso, ask the Commission to establish itself as the forum of last resort when states do not provide for full recovery of stranded costs.

[712] E.g., Coalition for Economic Competition, El Paso.

customers in their franchise areas. It asserts that utilities had to continue to invest in plant to satisfy their duty to serve. In addition, it submits that utilities had a reasonable expectation that they would continue to serve retail load because, among other things, state regulators set long amortization periods of 30–40 years for depreciation rates.

Some commenters state that the Commission also should ensure that stranded costs are recovered when a municipal utility annexes territory served by another utility or otherwise expands its service territory.[713] A number of commenters also urge the Commission to ensure recovery of costs that are stranded if a municipal utility or a newly-formed wholesale or municipal utility physically interconnects to another utility or builds new transmission or distribution facilities to the municipal system.[714]

Several commenters believe that close coordination between the Commission and state regulators as to the calculation of stranded costs is important in the case of municipalization.[715] A number of state commissions suggest that the Commission allow the states to set the level of retail-turned-wholesale stranded costs to be recovered in wholesale transmission rates set by the Commission.[716] They submit that this approach would respect state interests in controlling the rate impact of stranded costs, while allowing the Commission to design cost recovery, and would address the needs of industrial customers and other stakeholders by providing a forum before state regulators who will be more aware of their particular needs. Further, they contend that this approach would prevent relitigation of issues, minimize forum-shopping, and prevent legitimate and verifiable costs from falling through the cracks or being double-recovered.[717] NY Industrials asks the Commission to clarify that utilities will not be allowed to seek cost recovery at both the Commission and state commissions.

Commission Conclusion

We reaffirm our preliminary determination that this Commission should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. If such a customer is able to reach a new generation supplier because of the new open access (through the use of a FERC-filed open access transmission tariff or through transmission services ordered pursuant to section 211 of the FPA), we believe that any costs stranded as a result of this wholesale transmission access should be viewed as ''wholesale stranded costs.'' Such costs would not be stranded *but for* the action of this Commission (either through a mandatory FPA section 205–206 open access tariff or an order under FPA section 211) in permitting the new wholesale entity to become an unbundled transmission services customer of the utility and thereby to obtain power from a new supplier.[718] There is a clear nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. In these circumstances, we believe that this Commission should be the primary forum for addressing recovery of such costs. To avoid forum-shopping and duplicative litigation of the issue, we expect parties to raise claims before this Commission in the first instance.[719]

Some commenters have asked us also to be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory. We decline to do so because in these situations there is no direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. The risk of an existing municipal utility expanding its territory was a risk prior to the Energy Policy Act and prior to any open access requirement.

Nevertheless, we are concerned that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs.[720] We reserve the right to address such situations on a case-by-case basis.

As we indicated in the Supplemental Stranded Cost NOPR, if the state has permitted any recovery from departing retail-turned-wholesale customers (for example, if it imposed an exit fee prior to, or as a condition of, creating the wholesale entity), that amount will not, in fact, be stranded, and we will deduct that amount from the legitimate stranded costs for which we will allow recovery.

As discussed in Sections IV.J.8–IV.J.9, we will require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer, and will apply the same procedures for determining stranded cost obligation, as that required in the case of a wholesale requirements customer.

[713] *E.g.*, EEI, Minnesota Power, Centerior, Public Service Co of CO, SoCal Edison, Coalition for Economic Competition. PG&E asks that we allow utilities to seek recovery at the Commission for stranded costs attributable to former retail customers that have become customers of existing public agencies or municipal utilities where such costs cannot be collected at the state level.

[714] *E.g.*, Centerior, Coalition for Economic Competition, PG&E. Coalition for Economic Competition proposes that the Commission accept just and reasonable regional stranded cost recovery mechanisms in such situations to enable regional transmission associations (whether through pool and interpool arrangements or regional transmission groups) to collect through Commission-filed rate schedules from interconnected utilities charges equal to the costs otherwise stranded as a result of Commission-jurisdictional service realignments.

[715] *E.g.*, SoCal Edison, OH Com, NY Com, MI Com, Coalition on Federal-State Issues.

[716] *E.g.*, MI Com, NY Com, Ohio Com.

[717] PG&E proposes a similar approach, noting that if there are differences in the stranded cost method used by the Commission and the states, an incentive may remain for retail customers to municipalize merely to take advantage of more favorable stranded cost treatment at the Commission.

[718] Costs that are exposed to nonrecovery when a retail customer or a newly-created wholesale power sales customer ceases to purchase power from the utility and does not use the utility's transmission system to reach a new generation supplier (*e.g.*, through self-generation or use of another utility's transmission system) do not meet the definition of ''wholesale stranded costs'' for which this rule provides an opportunity for recovery. Such costs are outside the scope of this rule because such costs would not be stranded as a result of the new open access. *See* Section IV.J.12.

[719] We recognize that we took a different approach to retail-turned-wholesale stranded cost recovery in *United Illuminating*, where we suggested that state and local regulatory authorities or the courts should be able to provide an adequate forum to address retail franchise matters, including recovery of stranded costs caused by municipalization, but said we would consider revisiting the question if United Illuminating could demonstrate the lack of a forum. 63 FERC at 62,583–84. Since the issuance of that decision, however, we have had an opportunity to re-analyze the nature of the stranded cost problem in cases where a retail customer becomes a wholesale customer, including the potential that there might not be a state regulatory forum for recovery of such costs. In these circumstances, we have determined that where such costs are stranded as a result of wholesale open access transmission, these costs should be viewed as wholesale stranded costs and this Commission should be the primary forum for addressing their recovery.

[720] The CA Com has asked that, ''(t)o the extent of FERC's authority, it should assume jurisdiction to fulfill a backstop role in case retail customers evade a state-determined transition charge by becoming retail customers of an entity not subject to the state regulatory commission's jurisdiction. In assuming jurisdiction, the Commission should defer to the state commission's determination and allocation of stranded costs for the departing retail customer.'' CA Com March 18, 1996 Response to Supplemental Comments of PG&E.

7. Recovery of Stranded Costs Caused by Retail Wheeling

In the Supplemental Stranded Cost NOPR, we stated that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers who obtain retail wheeling from public utilities in order to reach a different generation supplier.[721] Because the vast majority of commenters urged the Commission not to assume responsibility for retail stranded costs, except in certain circumstances, we preliminarily concluded that it is appropriate to leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. We proposed to entertain requests to recover stranded costs caused by retail wheeling only when the state regulatory authority does not have authority under state law to address stranded costs at the time when the retail wheeling is required.[722] In so doing, we preliminarily accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern and thus, with the limited exception discussed above, generally must be recovered through retail charges.

We noted that the states have a number of mechanisms for addressing stranded costs caused by retail wheeling, one of which is a surcharge to state-jurisdictional rates for local distribution.[723] We encouraged the states to use the mechanisms available to them to address stranded costs.[724] We also noted that the states may use their jurisdiction over local distribution facilities to address ''stranded benefits,'' such as environmental benefits associated with conservation, load management, and other demand side management programs.[725]

Comments

A number of commenters support the Commission's proposal for addressing stranded costs caused by retail wheeling.[726]

Other commenters urge the Commission to take a greater role in retail stranded cost recovery and to entertain requests to recover stranded costs as a backstop where: (1) State regulatory authorities have the authority to address stranded costs but either choose not to exercise that authority or fail to permit full stranded cost recovery; [727] or (2) the state commission's authority is unclear.[728]

Commenters that support a greater Commission backstop role argue, among other things, that because the Commission has exclusive ratemaking jurisdiction over any stranded cost charges imposed ''for or in connection with'' interstate transmission service by public utilities, the Commission has an obligation to regulate the recovery of stranded costs from interstate retail transmission customers.[729] A number of these commenters argue that the determining factor is who has the jurisdiction to review the rates for the service, not who has the jurisdiction to order the service.[730] They explain that the Commission has jurisdiction over generating facilities and associated costs to the extent appropriate to establish just and reasonable rates for jurisdictional services. They disagree with other commenters who argue that only the jurisdiction under whose authority the costs were incurred and initially recovered should have authority to order recovery of stranded costs.[731]

These commenters contend that the Commission cannot abdicate its regulatory responsibilities by either deferring to the state commissions or otherwise failing to independently address the issue.[732] EEI and the Coalition for Economic Competition refer to ''a long line of cases (where) the courts have held that where a federal regulatory agency * * * is charged with implementing a statutory framework, that agency is without authority to deviate from or abdicate its statutory responsibilities.'' [733] According to Coalition for Economic Competition, for example, the Commission could satisfy its obligation to address stranded costs that arise from retail wheeling by allowing states to determine retail stranded cost charges in the first instance; to the extent that the state allows full recovery, Coalition for Economic Competition submits that the Commission's obligation would be satisfied.

EEI asserts that it would be unduly discriminatory and preferential for the Commission to refuse to address all stranded costs arising from retail wheeling. According to EEI, the same arguments that support the Commission's decision to address costs that are stranded where retail load municipalizes and where the state regulatory authority, at the time retail wheeling is required, lacks authority to act, apply with equal force to all other retail stranded costs. EEI submits that the nexus in these cases is that Commission-jurisdictional transmission service is the means by which the costs are stranded.[734]

Utility Working Group argues that the NOPR inappropriately characterizes the Commission's jurisdiction over retail stranded costs and that this could later be used against the Commission's exercise of its full authority. According to Utility Working Group, the NOPR depicts the Commission's jurisdiction as

[721] As discussed in Section IV.I, the Commission's authority to address retail stranded costs derives from its jurisdiction over the rates, terms and conditions of unbundled transmission in interstate commerce used by retail customers that obtain retail wheeling. The states' authority derives from state jurisdiction over local distribution facilities and over the service of delivering electric energy to end users, and from the authority to impose, among other things, retail exit fees and surcharges on local distribution rates.

[722] We proposed to require the same evidentiary demonstration for recovery of stranded costs from a retail customer that obtains retail wheeling as that required in the case of a wholesale requirements customer. We also reaffirmed our proposal in the initial Stranded Cost NOPR that a utility will have to show that the stranded costs are not more than the net revenues that the retail customer would have contributed to the utility had it remained a retail customer of the utility, and that the utility has taken and will take reasonable steps to mitigate stranded costs. FERC Stats. & Regs. ¶ 32,514 at 33,128.

[723] As we noted in the Supplemental NOPR, a state may require payment of an exit fee before a franchise customer is permitted to obtain unbundled retail wheeling. If local distribution facilities are used by a retail wheeling customer, the state may allow recovery of stranded costs through rates for use of such local distribution facilities. In addition, as discussed in Section IV.I, because we believe that states have authority over the *service* of delivering electric energy to end users, not merely the local distribution facilities themselves, state authorities can assign stranded costs and benefits through a local distribution service charge, and may do so based on usage (kWh), demand (kW), or any combination or method they find appropriate. If a state decides not to take any of these routes, it may consider whether to allow recovery of stranded costs from remaining retail customers or whether shareholders should bear all or part of those costs. *Id.* at 33,129.

[724] *Id.* at 33,129–30.

[725] *Id.* at 33,098 n. 230.

[726] *E.g.,* Utilicorp, Houston L&P, PG&E, Freedom Energy Co, WI Com.

[727] *E.g.,* EEI, EGA, Coalition for Economic Competition, Utilities for Improved Transition, Atlantic City, Arizona, Centerior, Com Ed, Detroit Edison, El Paso, LILCO, NU, NSP, NYSEG, United Illuminating, BG&E, Sierra, Southern, UT Industrials, NRECA. NRECA argues that unless the Commission addresses stranded costs caused by retail wheeling where a state commission lacks authority, or has authority but decides not to exercise it, there could be a jurisdictional gap into which many rural electric cooperatives could fall.

[728] *E.g.,* CSW.

[729] *E.g.,* EEI, Illinois Power, PSNM, Entergy, Nuclear Energy Institute, Coalition for Economic Competition.

[730] *E.g.,* Coalition for Economic Competition, Illinois Power, Utilities for Improved Transition, EEI.

[731] EEI notes, for example, that as use of electrical facilities shifts between retail and wholesale, jurisdiction over the rates to recover the allocated cost of service shifts between state commissions and this Commission, and that the regulatory authority is determined by the nature of the transactions and the classification of the customer, not the jurisdiction under which the costs originally arose.

[732] *E.g.,* Illinois Power, Utilities For Improved Transition, EEI, Coalition for Economic Competition.

[733] EEI Initial Comments at IV–13; *see also* Coalition for Economic Competition Initial Comments at 23–31.

[734] *See also* SoCal Edison.

being derived from state law (in other words, the Commission will act where state regulatory authorities have no authority over retail stranded costs and will not act where state regulatory authorities have such authority). If the Commission desires to afford substantial deference to the states regarding retail stranded costs, Utility Working Group contends that the final rule should reflect that policy determination; however, the rule should not confuse policy with jurisdiction by purporting to place limits on, or attempting to waive, the Commission's jurisdiction over such costs.

Entergy asserts that the Commission's jurisdiction over multi-state utilities provides further support for our jurisdiction over retail stranded costs in certain contexts. Entergy states that most of the eleven multi-state registered holding company systems have some form of Commission-jurisdictional agreement that allocates production and transmission costs among the systems' affiliated operating companies. It asserts that these agreements by their very nature allocate costs among jurisdictions (that is, between states). Many of these agreements equalize the cost of generating reserves among affiliated operating companies, and such reserve equalization formulas can shift retail stranded costs among states unless the Commission provides a regulatory forum to address cost-shifting. Citing *Middle South Energy*,[735] and *City of New Orleans* v. *FERC*,[736] Entergy submits that the Commission cannot sit on the sidelines when it comes to stranded retail costs on the Entergy system. According to Entergy, Commission and judicial precedent place on the Commission the responsibility to ensure that federally-approved costs and cost allocations are not undermined by state action.

Commenters also express concern that it will not be possible to be sure that a state regulatory authority has authority over retail stranded costs until after years of litigation. If the Commission waits for the resolution of challenges to state authority and a court holds that the state regulatory authority is without authority, these commenters assert that the bar on retroactive ratemaking could leave the states and the Commission without a remedy to compensate utilities for stranded costs.[737] A number of commenters suggest that while the states should be allowed to set retail wheeling stranded cost charges in the first instance, the Commission should accept filings to preserve a utility's ability to recover retail stranded costs from the time the customer departs if the state-authorized charges are not upheld in court. They submit that this would put customers on notice of the potential for Commission action and thereby avoid the retroactivity problem.[738]

Some commenters express concern that if the Commission does not take more decisive action on retail wheeling stranded costs, the result will be wasteful litigation that will discourage competition by causing financial uncertainty and higher financing costs for investor-owned utilities and higher rates for consumers.[739] Coalition for Economic Competition also asserts that stranded cost charges would be greatest at the start of a retail wheeling program, thereby making the years during which the state-authorized charges are subject to appeal more important for recovery purposes.

A number of commenters support Commission-established uniform standards for, and uniform recovery of, costs stranded as a result of open access to the interstate transmission system.[740] They argue that disparate state treatment of stranded costs would be economically inefficient and discriminatory and would burden interstate commerce.[741] Several commenters support state involvement in the establishment of uniform standards.[742]

In contrast to the commenters that support a greater Commission role in retail stranded cost recovery, NARUC and a number of other commenters oppose any Commission involvement in retail stranded costs.[743] These commenters contend, among other things, that the Commission lacks authority over these costs. Even if the Commission could assert such jurisdiction, they argue that as a policy matter it would be inappropriate for the Commission to delve into complicated legal and policy issues governed by varying state regulatory regimes.

According to some of these commenters,[744] section 201(a) of the FPA precludes an exercise of federal jurisdiction over retail stranded cost recovery because the Commission's jurisdiction extends ''only to those matters which are not subject to regulation by the States.'' [745] NM Industrials argues that a lack of state commission authority is an affirmative state determination, either by act or omission, that stranded costs must be dealt with in a particular manner. It submits that the Commission also lacks authority over retail stranded costs when states either decide not to address such costs or, in the Commission's opinion, grant insufficient recovery of stranded costs. NM Industrials asserts that the language of the FPA and its legislative history indicate that Congress wanted to preclude Commission jurisdiction in those areas where states could exercise effective control, and that this limitation covers all matters which are or can be regulated by the states, including the recovery of stranded investment. NM Industrials also suggests that assertion of Commission jurisdiction would violate the provision of section 212 of the FPA that prohibits the Commission from interfering with the states' authority over the transmission of energy directly to an ultimate consumer.[746]

Other commenters argue that the Commission's proposed treatment of retail stranded costs infringes on the states' jurisdiction over the allocation of costs that were under their jurisdiction when the costs were incurred. According to these commenters, the question of whether these costs should be recovered from other retail ratepayers, eliminated as excess capacity, or billed in some fashion to the customer now receiving wheeling service are purely questions of state ratemaking law.[747] Some commenters assert that, as a matter of policy, the Commission should stay out of retail stranded costs because only the states have sufficient knowledge and expertise regarding utility planning, investment,

[735] Opinion 234, 31 FERC ¶ 61,305, on reh'g, 32 FERC ¶ 61,425 (1985).

[736] 875 F.2d 903 (D.C. Cir. 1989), *cert. denied sub nom.* Mississippi v. FERC, 494 U.S. 1078 (1990).

[737] *E.g.*, NU, Coalition for Economic Competition, Illinois Power, EEI.

[738] *E.g.*, NEPCO, EEI, Coalition for Economic Competition, Entergy.

[739] *E.g.*, LILCO, Coalition for Economic Competition.

[740] *E.g.*, NU, NSP, Illinois Power, Coalition for Economic competition, PSE&G, Utilities For Improved Transition, Philip Morris, EEI.

[741] Freedom Energy Co. rejects this argument on the basis that state regulation has never been wholly consistent and yet utilities have not asked for federal unification of state ratemaking policies or resolution of differences.

[742] E.g., PSNM, GA Com, Omaha PPD, Illinois Power.

[743] *E.g.*, CA Com, MD Com, VA Com, IN Com, NH Com, NV Com, NY Com, OH Com, FL Com, AZ Com, TX Com, ELCON, NY Industrials, NY AG, NY Consumer Protection, MA DPU, Iowa Board, IN Industrials, Texas Industrials, NM Industrials, Reynolds, NYMEX, Legal Environmental Assistance, CO Consumers Counsel, NJ Ratepayer Advocate, IBM, ME Industrials, Jay, WEPCO, NH General Court.

[744] *E.g.*, NARUC, ELCON, NY Industrials, NM Industrials, NV Com.

[745] 16 U.S.C. 824(a).

[746] *See also* Freedom Energy Co. Reply Comments.

[747] *E.g.*, ELCON, PA Com, NY Industrials, ND Com, VA Com, NM Com.

and forecasting to address these costs adequately.[748]

Commenters also express concern that the possibility of Commission involvement in retail stranded cost recovery will encourage forum-shopping whenever state commission action is unfavorable, even when states have procedures to deal with stranded costs. They argue that the result would be endless litigation over where federal jurisdiction ends and where state jurisdiction begins. They suggest that if a state fails to address retail stranded cost recovery, the issue should be addressed in court or in state legislatures.[749] OH Com contends that a Commission policy that does not recognize states' authority over retail stranded costs would be a disincentive for states to permit retail wheeling.

A number of commenters argue that recovery of retail stranded costs is not directly implicated by any Commission or Congressional action—that most such costs would be created by retail wheeling, which is not the subject of the Commission's open access initiatives—and thus need not be dealt with as part of the final rule.[750]

Commenters seek a number of clarifications concerning the Commission's position on, and the procedures for, retail stranded cost recovery. A number of commenters ask the Commission to clarify the states' role with respect to retail stranded cost recovery.[751] Others address the type of evidence required to establish that the state regulatory authority lacks authority to address stranded costs when retail wheeling is required.[752]

Several commenters express concern that customers receiving retail wheeling not be able to evade state stranded cost charges.[753] IL Com says that the Commission's proposal for determining whether facilities are state-jurisdictional ''local distribution'' facilities or Commission-jurisdictional ''transmission'' facilities in interstate commerce may not always provide a state with the opportunity to recover retail stranded costs through distribution rate surcharges. It says that the Commission does not offer any assurances that the case-by-case application of the proposed ''functional-technical test'' will result in a finding that ''local distribution'' facilities are used in all retail wheeling scenarios. PG&E asks the Commission to provide that all retail customers that opt for direct transmission access by definition take service over local distribution facilities and therefore may be subjected to a state-determined distribution rate that includes stranded cost surcharges.

A number of commenters ask the Commission to clarify that, in issuing the final rule, the Commission is not endorsing (either implicitly or explicitly) retail wheeling.[754]

Several commenters express concern that stranded costs may arise in one state jurisdiction and be shifted to another.[755] For example, MT Com says that an analysis confined to a state's boundaries may reveal no stranded costs, but that such costs may indirectly arise because of common pool revenue recovery mechanisms, which may be the largest source of stranded costs for some utilities. Entergy raises a similar concern in the context of holding company or other multi-state situations. It argues that denial of retail stranded cost recovery by a state regulatory authority could harm customers in other states. Entergy proposes that, while state regulators should be given the opportunity in the first instance to assure that stranded costs are recovered and are not shifted to other states, the Commission should allow utilities to file retail wheeling tariffs with the Commission to preserve the right to seek recovery from the Commission.

Several commenters oppose Entergy's proposal.[756] Among other things, they argue that the FPA does not authorize the Commission to act as an appellate court over retail regulators. They assert that, in the case of a multi-state holding company system, it is the Commission-jurisdictional intra-system agreement (not a state's decision as to recovery of retail stranded costs) that determines the allocation of costs at wholesale among the affiliates. Several of these commenters suggest that if the holding company believes that, as a result of a state's disallowance of costs in retail rate base, the cost allocations under an intra-system agreement are unduly discriminatory, the holding company could propose to amend the agreement.[757]

A number of commenters also express concern that services that investor-owned utilities provide to promote energy efficiency and conservation and to assist low-income residents and the elderly be continued.[758] NW Conservation Act Coalition suggests that the Commission should condition stranded cost recovery upon a showing by the utility that allowing recovery will not strand such social benefits.[759]

Various commenters endorse the use by state regulators of a distribution charge or other fee imposed on electricity consumption to address stranded social benefits.[760] NARUC and OH Com express concern that the Commission, by claiming authority over unbundled retail transmission services, may make it difficult for states to use non-bypassable ''wires charges'' or ''access fees'' to require all customer classes to support such programs.[761] NARUC asks the Commission to ensure that any jurisdiction we exercise over unbundled transmission services does not legally or practically foreclose the ability of individual states to fund such programs.[762] LILCO, as part of its argument that the Commission should provide a complete backstop for stranded cost recovery resulting from retail wheeling, urges the Commission to establish retail wheeling rates that provide for full recovery of any stranded costs, including stranded social benefits,

748 *E.g.*, OH Com, NY Industrials, NM Com, IN Com, WA Com, NV Com, NY Com, Suffolk County, NY AG, Tonko, PA Industrials, NH General Court.

749 *E.g.*, OH Com, PA Com, NM Com, CA Com, Blue Ridge.

750 *E.g.*, Nucor, AEC & SMEPA.

751 *E.g.*, NY Industrials, EGA, NJ BPU, Coalition on Federal-State Issues.

752 *E.g.*, Iowa Board, Nevada Commission, CCEM; *see also* NE Public Power District.

753 *E.g.*, IL Com, PG&E, Public Service Co of CO.

754 *E.g.*, NRECA, Wisconsin EC, EEI, PECO, Missouri Basin Group.

755 *E.g.*, MT Com, Entergy.

756 *E.g.*, NARUC, Entergy Retail Regulators, MS Com, Al Com.

757 *E.g.*, NARUC, MS Com.

758 *E.g.*, Homelessness Alliance, Black Mayors, National Women's Caucus, Vann, La Raza.

759 NARUC and OH Com assert that, in determining whether a wholesale transmission transaction is a ''sham,'' the Commission should consider a retail customer's intent to bypass responsibility for supporting social programs.

760 *E.g.*, Natural Resources Defense, NW Conservation Act Coalition, Seattle, FTC, Northeast States for Coordinated Air Use Management, NARUC, OH Com. CO Com agrees that states should have the option to fund such programs through the imposition of surcharges on any form of electric service used to benefit retail customers, including surcharges on retail transmission rates. Seattle proposes either a simple fee on kWhs or a differential fee based on the type of resource and its environmental affects. DOE urges the Commission to work with state regulators to ensure that states have the ability to recover stranded retail costs and benefits in a way that prevents cost-shifting, forum-shopping, and uneconomic bypass (including bypass of stranded benefits).

761 CO Com notes that the NOPR proposes to limit states to funding mechanisms that can be implemented solely at the local distribution level, presumably through the use of a surcharge on distribution facilities or so-called ''fee at the meter'' or the use of a local distribution system revenue decoupling mechanism. It suggests that neither of these options may be legally or practically feasible in many states for a wide variety of reasons (but does not expand on these reasons).

762 Natural Resources Defense proposes that the Commission adopt the following language: ''The FPA does not affect state regulators' jurisdiction to apply distribution charges—either volume-based or fixed—to electricity that is used by any utility customer to provide end-use services (as distinguished from electricity that is purchased for resale to end-use customers).'' Natural Resources Defense Initial Comments at 3.

that are unrecovered after state stranded cost determinations.

Commission Conclusion

We believe that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in order to reach a different generation supplier, and that utilities are entitled, from both a legal and a policy perspective, to an opportunity to recover all of their prudently incurred costs. This Commission's authority to address retail stranded costs is based on our jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce. The authority of state commissions to address retail stranded costs is based on their jurisdiction over local distribution facilities and the service of delivering electric energy to end users. However, because it is a state decision to permit or require the retail wheeling that causes retail stranded costs to occur, we will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority [763] does not have authority under state law to address stranded costs when the retail wheeling is required.

Commenters that describe our action as an unlawful abdication or delegation of authority misconstrue the nature of our decision to leave retail stranded costs (with a limited exception) to state regulatory authorities.[764] We have not ''abdicated'' or ''delegated'' to state regulatory authorities our jurisdiction over the rates, terms, and conditions of retail transmission in interstate commerce; if retail transmission in interstate commerce by a public utility occurs, public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205. Instead, we have made a policy determination that the recovery of retail stranded costs—an issue over which either this Commission or state commissions could exercise authority by virtue of their jurisdiction over retail transmission in interstate commerce and over local distribution facilities and services, respectively—is primarily a matter of local or state concern that should be left with the state commissions. However, if the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required, then we will entertain requests to recover such costs.[765]

Because we have accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern, we will not allow the states to use the interstate transmission grid as a vehicle for passing through any retail stranded costs, with the following limited exception. If the state regulatory authority does not have authority under state law when the retail wheeling is required to resolve the retail stranded cost issue, we will permit a utility to seek a customer-specific surcharge to be added to an unbundled transmission rate.

We believe that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling.[766] In addition, as further discussed in Section IV.I, we are defining in this rule ''facilities used in local distribution'' under section 201(b)(1) of the FPA. Rates for services using such facilities to make a retail sale are state-jurisdictional, and states will be free to impose stranded costs caused by retail wheeling on facilities or services used in local distribution. States may also use their jurisdiction over local distribution facilities or services to recover so-called stranded benefits. This rule is not intended to preempt any existing state authority to assess a stranded cost or stranded benefits charge on a retail customer that obtains retail wheeling. Moreover, since the charge is state jurisdictional, it is of no moment to our responsibilities under the FPA as to whether such charges are volume-based (kWh), demand-based (kW), or customer-based (fixed).

We believe that our approach to retail wheeling stranded costs represents an appropriate balance between federal and state interests. This approach ensures that the rates for transmission in interstate commerce by public utilities (except in a narrow circumstance) will not be burdened by retail costs. It also helps to ensure that one state will not be able to impose costs stranded by its ordering of retail wheeling [767] on customers in another state.[768] In a holding company or other multi-state situation, we recognize that denial of retail stranded cost recovery by a state regulatory authority could, through operation of the reserve equalization formula in a Commission-jurisdictional intra-system agreement, inappropriately shift the disallowed costs to affiliated operating companies in other states. The Commission is concerned about this potential for cost-shifting. We would not wish to see an intra-system agreement used as a means for one jurisdiction to shift to other jurisdictions retail stranded costs for which it would otherwise be responsible under that agreement. However, we will deal with such situations if they arise pursuant to public utility filings under section 205 or complaints under section 206. Thus, the need to amend a jurisdictional agreement to prevent retail stranded costs from being shifted to customers in other states will be addressed on a case-by-case basis. We encourage the affected state commissions in such situations to seek a mutually agreeable approach to this potential problem. If such a consensus solution resulted in a filing to modify a jurisdictional agreement, we would accord such a proposal deference, particularly if other interested parties support the filing. In the event that the state commissions and

[763] ''State regulatory authority'' has the same meaning as provided in section 3(21) of the FPA.

[764] We reject the arguments of EEI and Coalition for Economic Competition that the Commission made findings in the initial stranded cost NOPR that ''inexorably'' lead to the conclusion that Commission action providing full recovery of retail stranded costs is required. Their reliance on *Williams Natural Gas Company* v. *FERC,* 872 F.2d 438 (D.C. Cir. 1989), *appeal after remand,* 943 F.2d 1320 (D.C. Cir. 1991) (*Williams*), is simply misplaced. *Williams* involved a rulemaking that was terminated by the Commission. The court stated that the Commission, ''having expressed these tentative views (that the incentive price for tight formation gas would disserve the public interest) and having solicited comments on the issue, was not free to terminate the rulemaking'' without providing a satisfactory explanation. 872 F.2d at 446, 450. Here, in contrast, we are issuing a Final Rule that reaffirms in many respects preliminary findings proposed in both the initial and Supplemental Stranded Cost NOPRs. Although the conclusion we reach based on those findings may be different than that which some commenters advocate, we have fully explained the basis for our decision.

[765] In these circumstances, the cases cited by commenters to support the proposition that an agency is not authorized to abdicate its statutory responsibilities or to delegate to parties and intervenors regulatory responsibilities (such as preparation of an environmental impact statement) are factually distinguishable and inapposite. *See, e.g.,* FPC v. Texaco, 417 U.S. 380, 394 (1974) (Commission cannot exempt small-producer rates from compliance with just and reasonable standard); United States v. City of Detroit, 720 F.2d 443, 451 (6th Cir. 1983) (district court inappropriately implied waiver of EPA statutory duty under Title II of the Federal Water Pollution Prevention and Control Act); State of Idaho v. ICC, 35 F.3d 585, 595–96 (D.C. Cir. 1994) (an agency cannot abdicate its NEPA responsibilities in favor of the regulated party).

[766] As discussed in the Supplemental NOPR (FERC Stats. & Regs. ¶ 32,514 at 33,129–30), these mechanisms include requiring an exit fee before a franchise customer is permitted to obtain unbundled retail wheeling and imposing a surcharge on local distribution rates. Commenters identified several other possible mechanisms in response to the initial Stranded Cost NOPR.

[767] As we stated in the Supplemental NOPR, we do not address whether states have the lawful authority to order retail wheeling in interstate commerce. *Id.* at 33,098 at n.228. In addition, we are neither endorsing nor discouraging retail wheeling.

[768] *See id.* at 33,098, 33,127–28.

other interested parties cannot reach consensus that would prevent cost shifting, the Commission would ultimately have to resolve the appropriate treatment of such stranded costs.

Should a situation arise in which a state regulatory authority concludes that it has no ability to address retail stranded costs, or the appropriate state courts ultimately determine that a state regulatory authority does not have authority to impose retail stranded costs, a utility may seek recovery here through its Commission-jurisdictional retail transmission rates of costs stranded as of the date of the customer's departure. Because all parties are put on notice by this Rule of the potential for recovery through Commission-jurisdictional retail transmission rates should state commission-authorized retail wheeling charges be invalidated, such recovery (if allowed) would not be retroactive ratemaking.[769]

8. Evidentiary Demonstration Necessary—Reasonable Expectation Standard

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary determination that a public utility or transmitting utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. We indicated that the existence of a notice of termination provision in a wholesale requirements contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision.[770] We proposed not to adopt a minimum notice period for purposes of applying the rebuttable presumption. This was because whether a utility has a reasonable expectation of continuing to serve a customer, and for how long, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provision in the contract, will depend on the facts of each case.

We sought further comment concerning whether the reasonable expectation standard should apply if a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and where, in order to make such a sale possible, transmission service has been rendered by an intervening utility. We asked whether the Commission should take this as conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended. We further asked should we choose to provide the seller with an opportunity to prove that it had a reasonable expectation, what weight should be given to the fact that transmission service was rendered by the intervening utility. If the seller establishes that it had a reasonable expectation, and the former wholesale customer does not take unbundled transmission service from the former seller, we asked what if any means ought to be available for the collection of stranded costs.[771]

We also proposed to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer or a retail customer that obtains retail wheeling as that required when a wholesale requirements customer leaves a utility's system. We proposed that the utility must demonstrate that it incurred stranded costs based on a reasonable expectation that the customer would continue to receive bundled retail services. We anticipated that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes a mandatory obligation to serve. We requested comments on these proposals.[772]

Comments

a. Rebuttable Presumption

Some commenters oppose treating a notice provision as a rebuttable presumption that the utility had no reasonable expectation of continuing to serve a customer. Commenters representing the financial community (Utility Shareholders and Utility Investors Analysts), for example, state that investment in generation and other costs incurred in providing utility service have not been tied to notice provisions. Based on the use of notice provisions in the past, and their infrequent use for termination, they state that the financial community has not viewed notice provisions as a determinant of the financial basis of investment in the industry.

Other commenters also argue that the Commission interprets the intent behind termination notice provisions too narrowly. These commenters submit that the Commission should examine on a case-by-case basis whether a notice provision demonstrates a sufficient meeting of the minds between the parties that there was no reasonable expectation that the contract would be extended.[773] TVA notes that the existence of a notice provision in its contracts in no way implies that continued service would not be expected.

A number of commenters[774] note that some utilities have ''evergreen'' contracts that remain in effect indefinitely unless either party gives notice that it intends to terminate the contract. They argue that, with no date certain for termination, the provider of bundled service must proceed on the assumption that it will have to meet its contract obligations on a continued basis. CSW recommends that the Commission limit the rebuttable presumption standard to contracts that contain a fixed contract termination date. IN Com suggests that where a contract contains an evergreen provision, the Commission should consider how often the contract has been automatically renewed and the length of the notice period.

A number of commenters suggest that the following factors should be conclusive proof of a reasonable expectation (or sufficient to conclusively rebut the presumption of no reasonable expectation): (1) An obligation under statute, certificate of public convenience and necessity, order or otherwise, granted to the utility to provide service to the area that includes the customer; (2) participation by the customer in regulatory proceedings that defer the utility's complete recovery of the costs associated with existing investment to a later period; or (3) service under a wholesale rate that averaged the cost of all of a utility's generation resources, both long-term and short-term.[775] Utilities For Improved Transition maintains that a customer whose rates were based on the totality of a utility's resources, including those with long life expectancies,

[769] *See* Public Utilities Commission of the *State of California* v. *FERC,* 988 F.2d 154, 163–66 (D.C. Cir. 1993).

[770] FERC Stats. & Regs. ¶ 32,514 at 33,117.

[771] *Id.* at 33,118.

[772] *Id.* at 33,128.

[773] *E.g.,* Carolina P&L, CSW, Duke, Utilities for Improved Transition, Montaup, TVA, MidAmerican. MidAmerican states that, for years, utilities have entered into wholesale contracts containing termination notice provisions and, for years, customers have renewed and renegotiated those contracts. Duke agrees that more important indications of the utility's reasonable expectation of continuing to serve the customer can be found where the service has been included in the IRP process or the contract has been repeatedly renewed. Orange & Rockland proposes that there be a rebuttable presumption of recovery for long-standing (at least 10 years) contracts between utility affiliates on the basis that the existence of a long-standing relationship is of greater significance than a notice provision.

[774] *E.g.,* CSW, IN Com.

[775] *E.g.,* El Paso, Utilities For Improved Transition.

cannot claim that the governing expectation was that the utility would serve the customer only for a period of one to three years.

Other commenters, in contrast, assert that the rebuttable presumption does not go far enough. These commenters submit that a notice of termination provision should create a conclusive presumption that a utility had no reasonable expectation of continuing to serve a customer beyond the notice period.[776] Some commenters [777] also support a conclusive presumption of no reasonable expectation where one or more of the following grounds are present: (1) An explicit termination provision, regardless of the length of the pre-termination notice period; (2) an explicit provision for decreasing service or switching to partial requirements service; (3) a pre-existing transmission tariff or transmission service schedule; (4) NRC license conditions providing for transmission service or pooling rights; [778] (5) a municipal joint action agency or G&T cooperative with authority to supply the wholesale load in question; (6) a fixed-term contract; (7) membership in a power pool that provides access to regional markets; (8) a contract entered into after passage of the Energy Policy Act; or (9) other evidence of an ability to seek alternative suppliers. Several of these commenters, such as TAPS and Detroit Edison Customers, submit that a conclusive, irrebuttable presumption would decrease the number of disputes over stranded cost issues.

Several comments were submitted concerning the examples listed in the NOPR that the Commission suggested, depending on all of the facts and circumstances, could establish a reasonable expectation that a contract would be extended. These examples include lack of access to alternative suppliers, repeated contract renewals, failure of a customer to object to the imposition of construction-work-in-progress, or communications between supplier and customer concerning including the customer's load in system planning.[779] Some commenters argue that evidence of this type should not be enough to rebut the presumption (or to overcome a summary judgment motion based on the presumption) of no reasonable expectation for contracts with notice provisions.[780] ELCON objects to using a customer's lack of alternative supply as evidence of a continued service obligation; it submits that the historic lack of supply alternatives has been caused by undue exercise of market power and should not be rewarded.[781] Las Cruces suggests that if lack of opposition to construction-work-in-progress evidences a reasonable expectation of continued service, continuous opposition should evidence a reasonable expectation that the customer will depart a system at the earliest possible date. With regard to the Commission's suggestion that communications with the customer on the customer's future plans could establish reasonable expectation, Direct Service Industries submits that no claimed reliance should be deemed reasonable unless the seller obtained express assurances from the customer that the customer intended to continue to purchase power from the seller beyond its current contract.

We also received comments on the time at which the reasonable expectation had to exist. TAPS urges that the Commission should focus on whether a utility had a reasonable expectation of continued service when it entered into the most recent execution, renewal or amendment of the power supply contract.[782] PSE&G, on the other hand, argues that the focus of the Commission's review should be whether, at the time of incurring or obligating itself to incur the cost of serving a customer, the utility had a reasonable expectation of serving that customer for its planning horizon.

b. Application of Reasonable Expectation Standard to Non-Contiguous Service Territory

Some commenters discuss the situation in which a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and, in order to make such a sale possible, transmission service has been rendered by an intervening utility. They argue that this situation presents conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended.[783] Direct Service Industries submits that if a customer has power supply options that do not rely on access to the selling utility's transmission system, the selling utility could have had no reasonable expectations other than those expressly created by contract. NM Industrials submits that allowing recovery of stranded costs in this situation would also constitute retroactive ratemaking in violation of *Arkansas Louisiana Gas Company* v. *Hall*.[784] It argues that by assessing stranded costs at the close of a contract's term against customers that do not even need a generating utility's transmission services to leave its system, the Commission would retroactively alter the terms and conditions of the rates for generation negotiated between the parties and approved by the Commission.

Other commenters submit that in these circumstances the Commission should give the supplier the opportunity to prove that it had a reasonable expectation that it would continue to serve the customer.[785] ELCON and WP&L state that the reasonable expectation standard should be satisfied (or not) by reference to the parties' existing contract, regardless of whether the customer is in a contiguous service territory.

Utility Investors Analysts asserts that a seller will always have a reasonable expectation that a business relationship can be continued with a current customer and that the better presumption would be that the contract will be extended unless evidence to the contrary exists.

[776] *See, e.g.,* ELCON, NRECA, APPA, American Forest & Paper, Central Montana EC, Municipal Energy Agency Nebraska, Arkansas Cities, Direct Service Industries, Atlantic City, TDU Systems, Fertilizer Institute, LG&E, ABATE, Oglethorpe.

[777] *E.g.,* TAPS, Missouri Joint Commission, Detroit Edison Customers, LEPA, APPA, Cleveland.

[778] According to LEPA, the normal set of NRC license conditions included an explicit wheeling commitment and many of the license conditions clearly referenced the possibility that the wheeling commitment would lead to the loss of customers to whom the utility had been selling bulk power supply as well as retail power. LEPA submits that acceptance of such license conditions should have ended any reasonable expectation that a utility might have had of continuing to serve a full requirements customer, wholesale or retail, after the termination of its contract.

[779] *See* FERC Stats. & Regs. ¶ 32,514 at 33,117.

[780] *E.g.,* TAPS, Phelps Dodge. Phelps Dodge suggests that evidence of past contract renewals, by itself, should not serve to rebut the presumption that the utility has no reasonable expectation of contract renewal in the future.

[781] In contrast, EEI believes that lack of access to alternative suppliers can be evidence that a utility reasonably expected to continue to serve a customer.

[782] If the investment now alleged to be stranded was incurred after the most recent amendment or extension to the contract, TAPS would focus the reasonable expectation review on such later date.

[783] *E.g.,* IL Com, Utilicorp, PSG&E, NM Industrials.

[784] 453 U.S. 571 (1981).

[785] E.g., Florida Power Corp, Consumers Power, FL Com, TDU Systems.

c. Application of Reasonable Expectation Standard to Retail-Turned-Wholesale Customers or To Retail Wheeling

A number of commenters support the Commission's proposal to apply the reasonable expectation standard in these cases.[786] PA Com submits that the case-by-case analysis contemplated by the Commission for establishing a utility's reasonable expectation of continuing to serve a wholesale requirements customer should also apply in the case of a retail-turned-wholesale customer or a retail customer that obtains retail wheeling.

Some commenters believe that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes an obligation to serve.[787] Some contend that the reasonable expectation standard should be presumed met in these circumstances because state law obligates a utility to serve all retail customers. A number of commenters assert that such a presumption would obviate the need for case-by-case showings concerning the expectations of each utility and the nature of each franchise.[788] At a minimum, several commenters propose that the Commission adopt a rebuttable presumption that utilities had an obligation to serve retail customers and therefore that the reasonable expectation test is met in a retail-turned-wholesale customer scenario or in the case of costs stranded as a result of retail wheeling.[789]

On the other hand, a number of commenters argue that there is no basis for a utility to reasonably expect that it will continue to serve a particular customer in states where franchises are non-exclusive.[790] Several of these commenters argue that a utility operating under a non-exclusive franchise is faced with the ever-present prospect that the communities it serves may build their own systems.[791]

Other commenters oppose the suggestion that the reasonable expectation test cannot be met where a franchise is non-exclusive or has terminated.[792] They argue that a utility's obligation to serve retail customers arises under state laws independent of the franchise. SoCal Edison explains that in states such as California, a franchise is nothing more than the source of a utility's right to use the city's streets, poles, rights of way, etc., and that a utility's duty to serve extends to all customers within its certificated service territories and not simply to those areas in which it has a franchise.

Commission Conclusion

We reaffirm that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. Whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, will be determined on a case-by-case basis, and will depend on all of the facts and circumstances.[793]

Further, we will apply the reasonable expectation standard in those cases where a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and, in order to make such a sale possible, transmission service has been rendered by an intervening utility. We believe it is appropriate to give the utility an opportunity to prove that it had a reasonable expectation of contract renewal in circumstances in which the remote customer becomes an unbundled transmission services customer of the former supplier.[794]

We also reaffirm our determination that the existence of a notice provision in a contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period. Whether or not a contract contains an ''evergreen'' or other automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case.

We will not adopt a minimum notice period for purposes of applying the reasonable expectation rebuttable presumption. Whether a utility had a reasonable expectation of continuing to serve a customer, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provisions in a contract, will depend on the facts of each case.

In addition, we reaffirm our preliminary determination to apply the reasonable expectation standard to retail-turned-wholesale customers. In this scenario, before the Commission will permit a utility to recover stranded costs, the utility must demonstrate that it incurred such costs based on a reasonable expectation that the retail-turned-wholesale customer would continue to receive bundled retail service. Whether the state law awards exclusive service territories and imposes a mandatory obligation to serve would be among the factors to be considered in determining whether the reasonable expectation test is met in a particular case.[795]

We further note that we are not addressing in this Rule who will bear the stranded costs caused by a departing generation customer if the Commission finds that the utility had no reasonable expectation of continuing to serve that

[786] *E.g.,* PA Com, Com Ed, CSW, United Illuminating, UFIT, PSNM, TDU Systems.

[787] *E.g.,* Com Ed, Central and Southwest, United Illuminating, Utilities For Improved Transition, Utility Investors Analysts, Utility Shareholders.

[788] E.g., EEI, Minnesota Power, PECO, Puget, Centerior, Florida Power Corp, FL Com, Southern, SoCal Edison, NEPCO, Consumers Power, Coalition for Economic Competition. NEPCO asserts that the Supplemental Stranded Cost NOPR does not cite any comments or evidence casting doubt on the Commission's initial proposal (in the initial Stranded Cost NOPR) not to apply the reasonable expectation test to retail-turned-wholesale or retail customers that obtain retail wheeling on the basis that utilities operating under an obligation to serve at retail necessarily have an entitlement to recover the costs prudently incurred in fulfillment of that obligation.

[789] *E.g.,* EEI, Detroit Edison, Centerior, Consumers Power, Ohio Edison.

[790] *E.g.,* Wing Group, Alma, Total Petroleum, Cleveland, ABATE, N.Y. Mayors, CAMU, Suffolk County.

[791] *E.g.,* Wing Group, Total Petroleum, ABATE, CAMU, NY Mayors. Proposals advanced by commenters to address non-exclusive franchises include suggestions that the Commission: summarily reject claims to recover retail stranded costs where the utility has a non-exclusive franchise and historically has been subject to retail competition (*e.g.,* Cleveland); apply a rebuttable presumption that a utility had no reasonable expectation of continued service where a municipal franchise is expiring and the municipality has put the retail supplier on notice that the municipality may seek an alternative source of power supply (*e.g.,* Las Cruces); or provide that no stranded cost claim will be entertained absent a showing, by reference to applicable state law, that the utility had an exclusive service franchise obligation or was otherwise subject to an obligation to serve the customer that is departing its system (*e.g.,* Phelps Dodge).

[792] *E.g.,* Utility Working Group, SoCal Edison, Florida Power Corp, PG&E. Referring to the Commission's statement that it expects the reasonable expectation test to be easily met in those instances in which state law awards exclusive territories *and* imposes a mandatory obligation to serve, Utility Working Group asks the Commission to make clear in the final rule that it did not intend by that example that utilities with non-exclusive service territories would be presumed to fail the reasonable expectation test. According to Utility Working Group, the focus of the test must be on the utility's obligation to serve, which may be separate from any franchise arrangements.

[793] The examples that the Commission provided in the Supplemental NOPR of possible ways to establish reasonable expectation were not intended to be dispositive of the issue. As we make clear in this Rule, whether a particular utility had a reasonable expectation that a contract would be extended will depend on all of the facts and circumstances.

[794] However, if the remote customer does not use the former supplying utility's open access tariff to reach the new supplier, there would be no ''wholesale stranded costs'' as that term is defined in this Rule. In this situation, we would not allow extra-contractual recovery of stranded costs. Thus, there would be no need to address reasonable expectation. *See* Section IV.J.12.

[795] The same procedures would apply to retail customers that obtain retail wheeling.

customer. As we suggested in the initial Stranded Cost NOPR,[796] we anticipate that, in such a case, a public utility will seek in subsequent requirements rate cases to have the costs reallocated among the remaining customers on its system. However, we will not prejudge that issue here.

9. Calculation of Recoverable Stranded Costs

In the Supplemental Stranded Cost NOPR, the Commission proposed that the determination of recoverable stranded costs be based on a ''revenues lost'' approach. Under this approach, stranded costs are calculated by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility's generation system. We cited several benefits that we believe a ''revenues lost'' approach offers over a hypothetical cost-of-service approach, including avoidance of an asset-by-asset review, minimization of cost allocation procedures, and ease of application.[797]

We sought comments on how to calculate what the utility's revenue stream would have been had the customer continued service. We also sought comments on how to calculate the revenues that the utility would receive in a competitive market for the stranded assets. This included whether we should require the utility to track the actual selling price of the power over time or require the utility to use an up-front approach (such as an estimate of the forecasted market value of the power for the period during which the customer would have taken service). We asked whether we should allow prices in futures markets or forward markets to be used in an up-front approach, assuming such financial instruments become available.[798]

We suggested that the revenues lost approach automatically takes account of mitigation measures because it reduces the amount of stranded costs recoverable by a utility by the market price of the power that the customer no longer takes. We noted that this is particularly so if mitigation is reflected through a one-time, up-front estimate of the future market value of the power and is not trued up over time. We sought comments regarding implementation of a mitigation requirement. If mitigation is trued up over time, we asked how the Commission should ensure that the utility takes all reasonable steps to mitigate its own costs so as to minimize what the customer would have paid. We also asked how the Commission should ensure that the utility does its best to sell the power at its highest possible value. In addition, we asked whether there are other mitigation measures that should be taken into account (such as efficiency improvements that a utility would have undertaken regardless of whether the particular customer continued to take power under its contract, or cost savings resulting from the buy-out of a fuel contract made possible by the customer's departure).[799]

With regard to determining how long a utility could have reasonably expected to keep a generation customer (which we will call the ''reasonable expectation period''), we preliminarily found that a one-size-fits-all approach is not appropriate. We sought further comment with respect to whether the Commission ought to establish presumptions or, in the alternative, absolute limits on a customer's maximum liability when a utility establishes that it had a reasonable expectation that the contract would be extended. We inquired whether it would be appropriate to pick an outer limit equal to the revenues that the utility would lose during the length of one additional contract extension period, or during the length of the utility's planning horizon. We also asked what other events or criteria might be used to establish either presumptions or absolute limits on the reasonable expectation period.[800]

In addition, we proposed procedures for providing a customer advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[801] We invited comments on these procedures.[802]

Comments

a. Revenues Lost Approach

Numerous commenters, including almost all investor-owned utility commenters, support the revenues lost approach for calculating stranded costs.[803] Among other things, commenters maintain that the revenues lost approach is fair, reliable, and less complicated than the asset-by-asset approach. As discussed below, while some of these commenters support an ''up-front'' determination of stranded costs with no subsequent adjustments, others prefer use of a true-up mechanism whereby a customer's responsibility for stranded costs is adjusted to the extent that the actual competitive market value is different from the estimated market value used to determine the customer's up-front stranded cost charge.

Other commenters, on the other hand, oppose the revenues lost approach.[804] Some commenters state that the revenues lost approach provides no incentive to mitigate stranded costs because, by permitting a utility to recoup from a departing generation customer the difference between the contract price and a power resale price, the utility receives the same total revenues regardless of whether the customer stays or leaves and regardless of whether the utility effectively mitigates stranded costs.[805] Others maintain that the revenues lost approach is imprecise.[806] Referencing the problems associated with avoided cost projections used in setting QF rates under PURPA, some of these commenters submit that the revenues lost approach also requires significant assumptions (regarding projected revenue streams, service levels, and generic market value forecasts).[807] Among the other criticisms of the revenues lost approach that are raised by commenters are that it leads to over-recovery of stranded costs,[808] is

[796] FERC Stats. & Regs. ¶ 32,507 at 32,872.

[797] *Id.* at 33,121.

[798] *Id.*

[799] *Id.* at 33,123. We also asked how revenues received as a result of mitigation measures should be reflected in the determination of the amount of recoverable stranded costs; what special accounts, if any, should be created to track revenue liability for specific customers, revenues from mitigation measures, and other revenues received by the utility that offset the stranded cost liability; whether any adjustment should be permitted to the revenues that the utility claims will be realized in a competitive market for its stranded assets, and if so, how often and under what circumstances. Further, we sought comments on whether there are special costs that warrant some special consideration in the determination of stranded cost liability under a revenues lost approach, and if so, how they should be treated. *Id.* at 33,121–22.

[800] *Id.* at 33,122.

[801] *Id.* at 33,114–15.

[802] *Id.* at 33,115.

[803] *E.g.*, Centerior, NYSEG, Florida Power Corp, Houston L&P, NIMO, Orange & Rockland, Com Ed, PSE&G, EEI, PECO, Texas Utilities, PG&E, SoCal Edison, Dayton P&L, El Paso, IL Com, United Illuminating, Nuclear Energy Institute.

[804] *E.g.*, LG&E, TAPS, TDU Systems, ABATE, Blue Ridge, NY Energy Buyers, WP&L, PA Com, KY Com, American National Power, ELCON, Texaco, UT Com, NARUC, NIEP, DE Muni, Reynolds, Knoxville, Alma, APPA, NY Industrials, IL Industrials, SC Public Service Authority, Caparo, American Forest & Paper.

[805] *E.g.*, NIEP, DE Muni and TDU Systems.

[806] *E.g.*, SC Public Service Authority, ABATE, NY Energy Buyers, NARUC, ELCON, American Forest and Paper, APPA.

[807] *E.g.*, NARUC, NYSEG.

[808] *E.g.*, NRECA, NIEP, TDU Systems.

anticompetitive,[809] and that it leads to cost shifting.[810] NARUC and TDU Systems also maintain that it is likely that assets stranded by a customer's departure from the utility's generation system will be used to serve new customers but that the revenues lost approach offers no method of accounting for such ''unstranding'' of assets.

A number of commenters request clarification of the stranded cost formula contained in the NOPR, including specific instructions regarding how to calculate the revenues the customer would have paid the utility had it remained a customer and the competitive market value of the power the customer would have purchased.[811] Some of these commenters suggest that the stranded cost issue will be more contentious if the final rule does not provide greater detail.[812] Several commenters request that the Commission issue a detailed list of recoverable costs.[813] A number of commenters propose detailed alternatives to, or variations of, the revenues lost approach.[814]

Numerous commenters urge the Commission to be flexible and not overly prescriptive regarding the calculation of the formula components.[815] These commenters generally recommend that the Commission judge each stranded cost proposal on a case-by-case basis.[816]

Definition and Calculation of Revenue Stream

Some commenters maintain that the revenue stream component should be calculated based on the present rates paid by the customer.[817] These commenters state that because present rates have been approved by various commissions, the costs have been shown to be legitimate, prudent, and verifiable.

Other commenters oppose the use of current rates to calculate the utility's revenue stream. WP&L believes that the use of current rates would be overly generous and recommends capping the revenue measure at a regional average rate rather than a utility-specific rate. A number of other commenters argue that the effects of competition should be factored into the revenue stream by using the rates for capacity and energy actually offered or available in the utility's marketplace, such as incentive and special rates, not just the tariff rates to a particular customer.[818] Several commenters support removal of rate of return-related revenues associated with stranded assets, including risk premiums that are designed to compensate for potential nonrecovery of stranded costs.[819] EEI, in contrast, opposes any disallowance of rate of return-related revenues on the grounds that such a disallowance would violate the constitutional bar against the taking of private property without just compensation. Electronic Data Systems recommends calculation of the revenue stream using projected rates that include the effects of future rate increases.

The Commission requested comments on what categories of costs, in addition to investment costs, should be eligible for stranded cost recovery. In response, many commenters support the inclusion in the revenue stream calculation of additional costs, termed ''special'' costs, that may not be currently reflected in the rates paid by the departing customers, but that were incurred to provide service to these customers.[820] ''Special'' costs include: (1) Nuclear decommissioning costs; (2) environmental obligations existing at the time of the customer's departure; (3) purchased power contracts; (4) buyouts and buydowns of purchased power contracts; and (5) all regulatory assets, including deferred costs of generating assets for which regulators have promised recovery, deferred taxes, transition costs for post-employment benefits other than pensions, and contingent liability.

Other commenters oppose the inclusion of ''special'' costs in the calculation of the revenue stream.[821] TAPS questions how a customer can be held responsible for a cost that, by definition, it was never under a contractual obligation to pay. WP&L states that suppliers' rates should already reflect reasonable estimates of decommissioning costs and, therefore, no additional recovery is warranted.

Some commenters argue that the calculation of stranded costs should include social costs, such as demand side management, environmental costs, low income assistance costs, and costs associated with the management of fish and wildlife.[822]

NARUC states that the Commission should not preempt the ability of states to establish competitively neutral programs, such as DSM and energy efficiency, environmental mitigation, and R&D.

Various commenters state that any determination of stranded costs should take into account all offsetting benefits realized by the transmission provider upon a customer's departure.[823] Some commenters describe these costs as ''stranded benefits.'' [824]

Most commenters favor the removal of avoided variable costs from the calculation of stranded costs on the basis that only fixed costs are truly stranded.

Some commenters support prioritizing stranded cost recovery.[825] These commenters argue that stranded costs should be categorized and ranked by the degree of responsibility that utilities had for their incurrence. Utilities would be allowed the greatest percentage of recovery for those stranded costs over which they had the least control.

Definition and Calculation of the Competitive Market Value

There generally was no consensus among the commenters concerning how

[809] *E.g.*, TDU Systems, Blue Ridge, NY Energy Buyers.

[810] *E.g.*, UT Com.

[811] *E.g.*, Utility Investors Analysts, Public Power Council, Atlantic City, EEI, PA Com, NYSEG, Central Montana EC, Nebraska Public Power District, LG&E ABATE.

[812] Several commenters (Illinois Power, Oklahoma G&E, and Utility Investors Analysts) suggest that the Commission hold a technical conference to discuss how best to define the calculation of the formula components.

[813] Central Montana EC and NY Energy Buyers.

[814] *See* EEI, Electronic Data Systems, Knoxville, NIMO, NYSEG, NY Energy Buyers, Reynolds.

[815] *E.g.*, Nuclear Energy Institute, EEI, Consumers Power, PA Com, Oklahoma G&E, Portland, Knoxville, MidAmerican, Seattle, Salt River, Washington and Oregon Energy Offices, SMUD, Caparo.

[816] Some commenters (*e.g.*, Alma, Freedom Energy) oppose such flexibility. Alma maintains that clarity of rules is needed to provide participants in the competitive market as much certainty as possible about stranded cost charges likely to be recovered before they engage in alternative transactions. Freedom Energy similarly supports across-the-board or generic standards, as opposed to a case-by-case approach.

[817] *E.g.*, Centerior, Com Ed, Duke, Entergy, Florida Power Corp, Utility Investors Analysts, CA Energy Co, CSW.

[818] *E.g.*, Alma, ABATE, DOD, TDU Systems, ELCON.

[819] *E.g.*, NRECA, CA Energy Co, ABATE, DOD.

[820] *E.g.*, EEI and various investor-owned utilities, Nuclear Energy Institute, NC Com, Legal Environmental Assistance, EPA, Utilities for Improved Transition, PA Com.

[821] *E.g.*, TAPS, WP&L, UT Industrials, UtiliCorp, American Forest & Paper.

[822] *E.g.*, DC Com, Sustainable Energy Policy, Washington and Oregon Energy Offices.

[823] *E.g.*, AEC & SMEPA, Electronic Data Systems, Freedom Energy Co, LG&E, American National Power, EGA, Entergy, AMP Ohio, TDU Systems, TAPS, Las Cruces.

[824] TDU Systems proposes that the Commission allow for the recovery of stranded benefits in one of two ways: (1) Require direct payment of stranded benefits to a wholesale purchaser whose contract is terminated; or (2) allow a party to continue to receive power at cost-based rates for a period sufficient for the purchaser to be ''transitioned'' into a competitive market.

[825] *E.g.*, ELCON, NY Energy Buyers, SMUD, Caparo.

to determine the revenues a utility would receive in a competitive market for the stranded assets, that is, the competitive market value.[826] Proposals for calculating competitive market value include using: (1) The marginal cost of the released capacity; (2) the long-run marginal cost of the most competitive incremental generation replacement technology; (3) the marginal cost of requirements service; (4) a combination of the marginal costs of the utility, alternative suppliers, and others; (5) the cost of a combined cycle combustion turbine; (6) the price paid by the departing generation customer; (7) the highest price available in the market; and (8) auctions. In addition, to the extent that a futures market is sufficiently well-developed when the Commission issues a final rule, several commenters believe that futures market prices could be used as an estimate of market value.[827]

MT Com contrasts the effect of using short-term nonfirm prices instead of long-term firm prices as the competitive market value. It states that if short-term nonfirm prices are used, the stranded cost estimate would be higher, because the market price of short-term nonfirm power is lower than both the market price of long-term firm power and the embedded cost price.

Some commenters express concern regarding the difficulty of determining the market value of the displaced capacity under the revenues lost approach.[828] Among other things, commenters note that because a competitive market does not yet exist, the market price cannot be calculated in advance. For this reason, several commenters support an after-the-fact determination of market value.[829]

Snapshot Approach vs. True-Ups

Commenters are split on whether the revenues lost approach should use a one-time snapshot approach [830] or whether true-ups should be required or allowed.[831] The primary rationale offered in support of a snapshot approach is certainty;[832] the primary rationale offered in support of true-ups is accuracy.

Commenters that support true-ups note the inaccuracy associated with long-term avoided cost estimates contained in PURPA-mandated QF contracts and maintain that the projections required by the revenues lost approach will produce similarly disastrous results if true-ups are not permitted. As a component of the true-up calculation, some commenters favor inclusion of revenues associated with future load growth of remaining customers.[833] According to Electronic Data Systems, if these revenues are not included in a true-up calculation, the utility could over- or under-collect stranded costs, depending on whether and what type of load growth is anticipated. CA Energy Co and American National Power recommend consideration of load growth of remaining customers as a mitigating factor because the load increases of these customers allow the sale of the stranded capacity. CSW, on the other hand, opposes using the future load growth of remaining customers as a mitigation device. CSW states that the benefits of growth on the former supplier's system should flow to the customers who remain customers of that system. Ohio Ed agrees, except where the customer proves that the utility has deferred or cancelled capacity resource additions in response to departing customers.

Other commenters suggest that the Commission should not prescribe one method over the other.[834] EGA, for example, states that customers should have the choice of paying either a projected fixed amount or a charge that is periodically trued up.

Mitigation

A number of commenters agree that the revenues lost approach effectively encompasses mitigation.[835] Others argue that mitigation should (or could) be accomplished through divestiture of assets or capacity auctions.[836] LG&E states that a utility requesting recovery of stranded costs should be required to auction that portion of its system to the highest bidder. The difference between the auction price and the depreciated value of the auctioned assets could be used to determine stranded costs. However, LG&E does not advocate complete recovery of this difference; rather, it argues that this amount could be used as a starting point.

Several commenters argue that the revenues lost approach can produce anticompetitive results if capacity auctions or divestiture are not required.[837] A number of these commenters contend that utilities that recover significant stranded costs (while still maintaining control over the stranded capacity) can use the freed capacity to make sales in the market at subsidized prices. They maintain that these utilities do not have to worry about recovery of fixed costs because those costs are recovered by the stranded cost charge. According to these commenters, utilities can then remarket (or ''dump'') stranded capacity at artificially low prices (made possible by the subsidy from the stranded cost recovery) and thereby gain a competitive advantage in other transactions.[838] If the utilities are permitted to remarket the displaced capacity, CA Energy Co states that market-sensitive floor prices should be set to prevent utilities from reselling power from stranded assets at artificially low prices.

Suggestions as to how to prevent such anticompetitive consequences include allowing the customer to own or control the residual asset or amount of stranded capacity equivalent to the lost revenues. According to EGA, the customer could market the capacity it would have had to pay for through stranded cost charges and thus prevent the utility from remarketing the capacity after it has been paid stranded costs.

Several commenters take a harder line and would require suppliers seeking stranded cost recovery to offer for sale to the departing customer a ''slice'' of their system.[839] TDU Systems states that the purchase of an undivided slice of the system is superior to divestiture of a specific asset because the utility cannot keep the wheat and leave the purchaser with the chaff. TDU Systems would also make purchase rights to the system assignable. According to TDU

[826] *E.g.*, Centerior, Duke, Entergy, Com Ed, Houston L&P, Florida Power Corp, Carolina P&L, NRRI, WP&L, DOE, CSW, UtiliCorp, LG&E, FL Com.

[827] *E.g.*, WP&L, DOD, Duke, PSNM, ABATE, Houston L&P. The Commission notes that the New York Mercantile Exchange only recently began trading in electricity futures and that such trading was limited to two delivery points located within the Western Interconnection.

[828] *E.g.*, MI Com, NSP, NY Energy Buyers, KS Com.

[829] *E.g.*, KS Com, NY Energy Buyers.

[830] Commenters that support a one-time, up-front approach include FL Com, Dayton P&L, Portland, DE Muni.

[831] Commenters that support true-ups include ELCON, NYSEG, MN DPS, Reynolds, TAPS, NIMO, DOE, Electric Consumers Alliance, Com Ed, United Illuminating, SoCal Edison.

[832] DE Muni urges rejection of true-ups on the basis that true-ups represent guaranteed recovery of 100 percent of stranded costs.

[833] *E.g.*, Electronic Data Systems, Alma, American National Power, CA Energy Co, NARUC, NRECA.

[834] *E.g.*, Atlantic City Electric, EGA, Conservation Law Foundation.

[835] *E.g.*, Utility Investors Analysts, Duke, PSE&G, Com Ed, United Illuminating, Entergy.

[836] *E.g.*, NIEP, LG&E, TDU Systems, EGA, NY Energy Buyers, ELCON, American National Power.

[837] *E.g.*, LG&E, Allegheny, TDU Systems, EGA, AMP Ohio, CA Energy Co, WP&L, Torco.

[838] CA Energy Co maintains that an anticompetitive intent could be hidden by the argument that power must be dumped to mitigate stranded costs. It thus submits that, even without intending to do so, a utility could cripple competition by depressing market rates to artificially low levels.

[839] *E.g.*, TDU Systems, Arkansas EC.

Systems, this mitigation scheme is the only possible way to justify the revenues lost approach. TDU Systems argues that this proposal would inflict no harm on the utility, which would be fully compensated for the stranded assets. It also suggests that the ability to purchase a slice of the supplier's system would serve as an important bargaining tool in stranded cost negotiations, which would help level the playing field among the parties.

Other mitigation proposals include: (i) Requiring each utility to prepare a mitigation plan under the supervision of an independent expert that must be approved by the parties or by the Commission before stranded cost recovery is permitted; [840] (ii) requiring a utility to report annually for a five-year period its mitigation activities and to identify its stranded costs yet to be recovered; [841] and (iii) setting the market value of the displaced capacity at a high level (thereby reducing the stranded cost charge) to provide a mitigation incentive.[842] A number of commenters support customer-controlled mitigation, arguing, among other things, that the entity responsible for paying stranded costs has the best incentive to mitigate them.[843] Others support some form of utility sharing of stranded costs to give utilities an incentive to mitigate stranded costs.[844]

b. Reasonable Expectation Period (Period of Expected Continued Service)

Numerous commenters oppose setting absolute limits on the period over which a customer's liability for stranded costs would be determined.[845] They suggest instead that the Commission should apply the facts of each case, including the facts used to prove a reasonable expectation of continued service, to its determination of a reasonable expectation period. Among the factors commenters propose for consideration are: the utility's planning horizon; the average remaining life of the utility's generating facilities or a specific number of years that coincides with the duration of a utility-specific stranded cost recovery plan; utility projected load growth; dedicated facility construction lead times; estimated time to market stranded assets; the lesser of the utility's need date for new generation or the cross-over date when the market generation price is expected to equal a customer's embedded cost less other charges and compensation; and the period for which estimated revenues exceed market values. Commenters representing the financial community [846] oppose limiting cost recovery from the departing generation customer based on the term of the contract. They argue that it was reasonable for a utility to expect to continue to serve a customer, or customers who would take its place, through the life of the assets; otherwise, the asset could not have been financed in the first place.

A number of other commenters urge the Commission to prescribe limits on a customer's maximum liability.[847] Some commenters believe that the utility's planning horizon is the reasonable expectation period.[848] PSE&G states that since utilities invested and incurred costs to serve customers based on the planning horizon, the planning horizon is the only logical period. Other commenters propose that the reasonable expectation period be limited to one contract extension period, or to the shortest of: (i) One additional contract renewal period; (ii) the utility's planning horizon; (iii) the period it would/does take for load growth on the seller's system to absorb the lost load; or (iv) the contractual notice period.[849] Other suggested limits include the weighted average remaining life of all generating assets; [850] the in-service date of the utility's next avoidable generating unit or purchased power contract that is projected to have a capacity factor comparable to the departing generation customer's load factor minus a one-time mitigation effort; [851] and a rebuttable presumption that two years is the maximum time for a utility reasonably to expect to receive revenue from tariff sales or ''open-ended'' contracts.[852]

Other commenters propose recovery periods that range from three to five years (*e.g.,* Central Montana EC),[853] five years (*e.g.,* Public Power Council), and eight years (*e.g.,* Allegheny).[854]

GA Com and AZ Com state that stranded cost recovery should not go on indefinitely. GA Com states that stranded costs should be collected for a sufficient period of time to ensure full recovery and indifference on the part of the utilities' remaining native load customers. AZ Com states that a specific termination period will also create an incentive for utilities to mitigate stranded costs.

c. Proposed Stranded Cost Recovery Procedures

Several commenters [855] urge the Commission to be flexible in evaluating proposed mechanisms for recovery of stranded costs, including the payment method, noting that an approach suitable to one utility and its customers may not be suitable to another. They say that utilities within a region might find a mechanism that meets their region's unique characteristics.

Some commenters oppose certain aspects of the procedures proposed in the NOPR. For example, TAPS objects that the NOPR procedure aimed at providing advance notice to the customer of its potential stranded cost obligation resembles the procedure rejected in *Cajun.* It says that ''the customer will likely be forced to spend significant time and resources 'litigat[ing] to determine the price of a product(,)' thereby 'introduc[ing] deal-killing transactional costs and uncertainties.' '' (citing *Cajun,* 28 F.3d at 179). TAPS proposes that the seller be required to produce a stranded cost estimate that reflects a good faith, reasonable estimate of the likely impact of mitigation and that sellers making excessive and unsupported stranded cost claims be penalized. At a minimum, it argues that the seller should be held responsible for the costs

[840] *See, e.g.,* CA Energy Co.

[841] *See, e.g.,* PSNM.

[842] *See* WP&L.

[843] *E.g.,* EEI, PA Com, AMP Ohio, TAPS.

[844] *E.g.,* ABATE, Fertilizer Institute, IL Com, KS Com, San Francisco, UT Industrials, ELCON, CA Energy Co, MT Com, Caparo, WA Com, Education, NRRI, NY Energy Buyers, Reynolds, DOD, DC Com.

[845] *See, e.g.,* Florida Power Corp, Central and South West, Com Ed, EEI, Montana, PECO, Minnesota DPS, NIMO, NSP, SoCal Edison, PA Com, Central Louisiana, Utility Investors Analysts, Salt River, Orange & Rockland.

[846] *E.g.,* Utility Investors Analysts and Utility Shareholders.

[847] *E.g.,* NIEP, TAPS, Allegheny, Central Montana, Municipal Energy Agency Nebraska, PSNM, ABATE, ELCON, PSE&G, UtiliCorp.

[848] *E.g.,* PSE&G, PSNM, ELCON, Oklahoma G&E, Duke. Oklahoma G&E supports use of the utility's planning cycle for retail stranded costs and use of the contract term for wholesale stranded costs. Duke states that the Commission should permit the customer and the transmission provider to establish the compensation period at something less than the maximum period.

[849] *E.g.,* UtiliCorp, WP&L, Missouri Joint Commission, TAPS, Municipal Energy Agency Nebraska, TDU Systems.

[850] *E.g.,* Carolina P&L.

[851] *E.g.,* FL Com.

[852] *E.g.,* UT Industrials.

[853] Central Montana describes as ''excessive'' the recovery period offered to it by Montana. Central Montana states that it gave notice under a five-year notice provision and that Montana responded with a stranded cost demand extending 14 years after notice of termination (nine years from the date service would terminate).

[854] Allegheny would exempt three types of stranded costs from such a limit: (1) Those due to PURPA power purchases (it submits that these were federally-mandated rather than profit-motivated business decisions); (2) those due to regulatory assets (such as deferred taxes); and (3) those due to municipalization. In addition, it favors establishing a rebuttable presumption that these special costs are eligible for stranded cost recovery.

[855] *E.g.,* EEI, Centerior, PECO, Houston L&P, Salt River.

reasonably expended by the buyer to litigate the stranded cost claim.

DE Muni asserts that if filing a complaint to redress grievances related to the recovery of stranded costs is to be a meaningful remedy, the final rule should set a time limit within which the complaint must be resolved.

A number of commenters offer modifications to the recovery procedures set forth in the NOPR, including: (1) Extending a utility's response time for providing stranded cost liability estimates from 30 days to at least 60 days;[856] (2) requiring a utility to provide to each wholesale customer within six months of the effective date of the final rule: (a) The formula that the utility proposes to use to calculate the customer's maximum possible stranded cost exposure without mitigation; and (b) an actual calculation of the customer's stranded cost exposure assuming the customer left the utility's system six months after the effective date of the final rule;[857] (3) allowing customers that desire to litigate their stranded cost liability to do so in a forum in which all litigating customers participate;[858] (4) requiring utilities to disclose their estimated transition cost liabilities (and the nature of those liabilities) before the effective date of the final rule to permit a realistic evaluation of the scope of the transition cost problem and possibly facilitate resolution of some disputes by settlement;[859] (5) requiring any utility seeking stranded cost recovery to provide a list of the stranded facilities to the departing generation customer and offer that customer an equity position in those facilities in return for payment of stranded costs, thereby enabling the departing customer to recover some of its stranded costs payment when any of the facilities becomes useful again;[860] (6) requiring a ''good faith request'' for an estimate of stranded costs based on an expected date of departure from the providing utility's system and mitigation efforts expected to be undertaken by the utility;[861] and (7) requiring documented evidence that a utility made a good faith attempt to settle with a departing generation customer before the utility is given the opportunity to recover stranded costs.[862]

[856] *E.g.*, Entergy.

[857] *E.g.*, Associated Power.

[858] *E.g.*, Associated Power.

[859] *E.g.*, Texaco.

[860] *E.g.*, Heartland.

[861] *E.g.*, PSNM, ELCON.

[862] *E.g.*, ELCON.

Commission Conclusion

We reaffirm our proposal that the determination of recoverable stranded costs should be based on the ''revenues lost'' approach. We find that the revenues lost approach is the fairest and most efficient way to balance the competing interests of those involved.

After careful consideration of the comments submitted, we have decided to adopt the following formula for calculating a departing generation customer's stranded cost obligation (SCO), on a present value basis, under a revenues lost approach:

$SCO=(RSE-CMVE\times L$

where:

RSE=Revenue Stream Estimate—average annual revenues from the departing generation customer over the three years prior to the customer's departure (with the variable cost component of the revenues clearly identified), less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.[863]

CMVE=Competitive Market Value Estimate—determined in one of two ways, *at the customer's option:* Option (1)—the utility's estimate of the average annual revenues (over the reasonable expectation period ''L'' discussed below) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or Option (2)—the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

L=Length of Obligation (reasonable expectation period)—refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer. We reaffirm that we do not believe that a one-size-fits-all approach is appropriate for determining the length of a customer's obligation. If the parties cannot reach agreement as to the length of the customer's obligation, this period is to be determined through litigation as a part of the threshold issue of whether the utility had a reasonable expectation of continuing to serve the customer.

Application of the foregoing formula and collection of the resulting stranded costs are subject to the following conditions:

1. Cap on SCO. The quantity (RSE–CMVE) can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer.

2. Changes in Customer Revenues. If the customer's rates (or *contract demand* amounts, if relevant) changed during the three-year period prior to the termination of its existing requirements contract, then the RSE should be calculated using the customer's most recent 12 months of revenue.

3. CMVE Option 2 Conditions. Option 2 (a CMVE equal to the average cost to the customer of replacement capacity and associated energy) would be available to a customer whose alternative purchase(s) runs concurrent with L, or, if longer than L, contains rates that do not fluctuate over the duration of the contract. The customer would be required to demonstrate (at the time it chooses this option) that the replacement capacity contract(s) is for service equivalent to the released capacity (that is, firm power for a period at least equal to L), and must also clearly identify the rates to be paid for the replacement service.

4. Payment Options. The method and term of payment should be negotiated, but is ultimately left to the customer's discretion. Possible payment options include a lump-sum payment, an amortization of a lump-sum payment over a reasonable period of time, or a surcharge on the customer's transmission rate.

5. Applicability. The formula is designed for determining stranded costs associated with departing wholesale generation customers and for retail-turned-wholesale customers.[864]

6. Marketing/Brokering Option. The Commission will allow the customer, at its sole discretion, a choice to market the released capacity and associated energy (or to contract with a marketer for such service). Alternatively, the customer may choose to broker the released capacity and associated energy (or to contract with a broker).[865]

[863] In the case of a retail-turned-wholesale customer, subtraction of distribution system-related costs may also be appropriate.

[864] The formula is not to be used for recovering stranded costs associated with retail wheeling. We believe the formula is unworkable in this scenario because one of its key elements—the option for a customer to market or broker the utility's power—may not be practicable for retail customers. Therefore, stranded costs associated with retail wheeling will be determined on a case-by-case basis.

[865] The customer may also decide to remain a requirements customer for L. If the customer elects to remain a requirements customer, the utility will be obligated to continue service to the customer for the duration of L.

7. Released Capacity and Associated Energy. A utility requesting stranded cost recovery must indicate the amount of system capacity and the amount of associated energy released by the departing generation customer and used in the revenues lost calculation. This will allow the departing generation customer to fairly consider exercising a choice to market or broker the released capacity and associated energy.

The formula balances a number of goals, including: (1) Ensuring full recovery of legitimate, prudent and verifiable stranded costs; (2) requiring the utility to mitigate stranded costs; (3) providing certainty for departing generation customers; and (4) creating incentives for the parties to renegotiate their existing requirements contracts or otherwise settle stranded cost claims without resort to litigation.

Contrary to the objections of some commenters that the revenues lost approach creates no incentive to mitigate stranded costs, the formula automatically encompasses mitigation by reducing the departing generation customer's stranded cost obligation by the competitive market value of the released capacity and associated energy. Further, the option provided in the formula for a customer to market or broker the released capacity and associated energy protects the customer from a utility trying to overrecover stranded costs by estimating a low value for the released capacity and associated energy and thereby provides the customer some assurance that stranded costs will be minimized. Specifically, if a customer believes the utility's competitive market value estimate (CMVE) is too low, it can market or broker the released capacity and associated energy and reduce its stranded cost obligation.[866] We accordingly will not impose a separate mitigation obligation on the utility above that which is already subsumed in the revenues lost approach. In addition, a utility will continue to be subject to an ongoing prudence obligation to sell excess capacity off-system and/or to dispose of uneconomic assets.

We recognize that some commenters oppose the revenues lost approach as imprecise. However, any ratemaking method that relies on estimates will be subject to forecasting error. Moreover, in direct response to commenter concerns, we have gone to great lengths in this rule to provide specificity with respect to the calculation of the components of the formula. We believe that use of the formula will narrow the scope of disputes over the calculation of stranded costs, lend precision to the stranded cost amount it produces, and provide certainty to departing generation customers with respect to their stranded cost obligations.

Calculation of the Revenue Stream Estimate (RSE)

The RSE component of the formula is based on revenues paid by the departing generation customer during the last three years of its contract or retail service. We believe that the use of ''present'' revenues in the calculation of the revenue stream has numerous advantages over other approaches advocated. The use of present revenues eliminates disputes over estimates of future revenues, thereby adding certainty to the calculation. It also eliminates the need for a detailed listing of includable costs, relying instead on the assumption that present rates include all of the utility's costs of providing service. Further, the rates that produce present revenues have been approved by regulators, which strongly suggests that the costs included in them are prudent, legitimate and verifiable.[867]

We reject the suggestion by commenters that a utility be required to calculate the revenue stream using any lower rate being offered by the utility for service comparable to that being taken by the customer when the customer departs the utility's generation system. A revenue stream calculated in this manner could deny a utility the opportunity to fully recover its stranded costs or could shift costs to other customers, a result we find unacceptable. Similarly, the elimination of return-related revenues from the revenue stream effectively would require shareholders to absorb stranded costs, which is contrary to our determination that a utility is entitled to an opportunity to fully recover legitimate, prudent and verifiable stranded costs.

Calculation of the Competitive Market Value Estimate (CMVE)

We recognize the difficulty associated with estimating the competitive market value of the capacity and associated energy not purchased by the departing generation customer. However, we believe that an up-front estimate, which provides flexibility to the utility and a measure of certainty to customers, is superior to other proposals, provided the right mix of incentives and options is included in the formula.

A utility requesting stranded cost recovery must estimate CMVE based on a market analysis, with all assumptions and work papers made available to the departing generation customer. This provides a utility with the flexibility to choose the methodology that it feels produces the best estimate of the competitive market value of the released capacity and associated energy. We note that numerous proposals for calculating competitive market value were made in the comments. The Commission believes that the flexibility provided by the formula we adopt in this Rule permits the filing utility to avail itself of many of these recommendations.

At the same time, a utility may have an incentive to underestimate CMVE and thereby increase the stranded costs charge. To address this issue, the formula contains several features designed to create an incentive to produce a good faith estimate of stranded costs and to safeguard customers if a utility fails to do so. For example, the formula provides a departing generation customer with the option to market or broker the released capacity and associated energy if it believes the utility's estimate is too low. If the marketing option is chosen, the customer would buy the released capacity from the utility at the utility's market value estimate. The associated energy would be purchased at the utility's average system variable cost. The customer would then resell the released capacity and energy and keep the resulting revenues. If the revenues it receives are greater than the utility's market value estimate, the customer will have reduced its stranded cost obligation. If the customer chooses the brokering option and the released capacity and associated energy are purchased by a third-party for more than the utility's market value estimate, the difference between the average annual revenues produced by the sale and the utility's CMVE estimate will be used to lower the customer's stranded cost obligation. The utility may be required to show in a compliance filing that it has reduced the customer's stranded cost obligation under such circumstances.

If the customer chooses CMVE Option 2 and meets its conditions, CMVE will be set at the average price that the customer pays its new supplier. The customer will test the market and choose the best deal available. Hence,

[866] This option also addresses the concerns of commenters that, by failing to require auctions or divestiture of stranded capacity, the Rule would allow a utility recovering stranded costs to sell the freed capacity at subsidized prices, thereby gaining a competitive advantage in other transactions. If the customer avails itself of this option, the utility would no longer control the released capacity.

[867] The present rates, whether established by settlement or otherwise, have been found to be just and reasonable. In other words, they are neither confiscatory nor exorbitant.

the price the customer pays its alternative supplier is arguably a more accurate measure of the competitive market value of the capacity and associated energy not taken from the host utility. Whether to exercise Option 2 resides solely with the customer.

We further note that the sale of all or part of a utility's generating assets could be used as a method to determine competitive market value of such assets. Under the theory that an asset sale price reflects the highest value for the utility's assets, the Commission would presume that the competitive market value established under an open asset sale (*i.e.*, an offer to sell assets to any taker) would fully satisfy the utility's responsibility to minimize stranded costs. If a stranded cost claim involves divestiture of assets, the amount of stranded costs associated with those assets would be the book value less the sale price. The Commission would determine the appropriate stranded cost charge based on the facts presented.

Snapshot Approach Versus True-Ups

The revenues lost formula is based on a one-time snapshot approach. We favor this approach over the true-up approach because it creates certainty and will produce reasonably accurate results. True-ups, on the other hand, while theoretically more accurate, require periodic recalculation of stranded costs, which creates ongoing uncertainty and disputes. In addition, true-ups will result in additional transaction costs. We believe that an approach that provides certainty and establishes cost responsibility up front is best for what is fundamentally a transition issue.

Implementation Procedures [868]

In the Supplemental Stranded Cost NOPR, we proposed procedures to provide a potential departing generation customer with advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[869] These procedures are modified as follows to incorporate the findings made in this rule:

(1) A customer may, at any time before the termination date specified in its existing wholesale requirements contract,[870] request the public utility to provide an estimate of the customer's stranded cost obligation based on the revenues lost formula contained in this Rule,[871] as of the date set forth in the customer's request. The customer should specify in its request, to the extent possible, pursuant to its rights under its power sales requirements contract with the seller,[872] the date on which the customer is considering substituting alternative generation for the requirements purchase and the amount of the substitute generation. Any remaining generation requirements to be purchased from the existing supplier after this date should be clearly indicated. The customer may seek further information on how the stranded cost charge would vary as a result of choosing different dates or different amounts of substitute purchases. The customer also should indicate its preferred payment method, such as a lump-sum payment, an amortization of a lump-sum payment, or a surcharge (such as monthly or annual) on the customer's transmission rate.

(2) The utility shall, within thirty days of receipt of the request, or other mutually agreed-upon period, provide the customer with an estimate of the customer's stranded cost obligation. The response shall include: (i) Estimates of RSE, CMVE, and L according to the revenues lost formula and based on the information supplied by the customer; (ii) supporting detail (including the underlying market analysis that forms the basis for the CMVE estimate) indicating how each element in the formula is derived to enable the customer to understand the basis for each element; (iii) a detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;[873] (iv) an estimate of the amount of released capacity and the amount of associated energy that would result from the customer's departure, based on the information supplied by the customer, including detailed support for the amount of the released capacity and the amount of associated energy, and the market value of each, for each year of the reasonable expectation period, and how those amounts are consistent with the RSE and CMVE estimates; and (v) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs (the proposed modification should also reflect the customer's chosen payment method).

(3) If the customer believes that: (i) The utility has failed to establish that it had a reasonable expectation of continuing to serve the customer beyond the contract term;[874] (ii) the proposed stranded cost charge (or any of the elements used to compute it) is unreasonable; (iii) the amount of released capacity and the amount of associated energy assumed to be sold is unreasonable; or (iv) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs is unreasonable, the customer will have thirty days in which to respond to the utility explaining why it disagrees. The Commission expects parties to attempt to resolve any disputed issues.

(4) If the parties are unable to resolve the matter using the procedures in (1)–(3) above, the customer may either: (a) File a petition for declaratory order, or a section 206 filing seeking to amend an existing requirements contract, to seek a Commission determination as to whether: (i) The utility has met the reasonable expectation standard; (ii) the proposed stranded cost charge satisfies the other evidentiary standards set forth in this Rule; (iii) the amount of released capacity and the amount of associated energy proposed by the utility is reasonable; or (iv) the utility's proposal for any contract amendment needed to implement the customer's payment of

[868] These procedures apply to a potential departing generation customer who is an existing wholesale requirements customer of a public utility, or a retail customer of a public utility who is contemplating becoming a wholesale transmission customer (such as through municipalization). They may be used at the option of the potential departing generation customer. An existing wholesale requirements customer may use the procedures in conjunction with, or in lieu of, a complaint under section 206 to amend its existing requirements contract to add an explicit stranded cost provision, as discussed in Section IV.J.5.

[869] FERC Stats. & Regs. ¶ 32,514 at 33,114–15; 33,128–29.

[870] If the customer is a retail customer contemplating becoming a wholesale transmission customer, it may at any time request the public utility to provide an estimate of its stranded cost obligation.

[871] Because the formula reduces a customer's stranded cost obligation by the competitive market value of the capacity and associated energy that would be released by the customer's departure, we will not adopt the proposal in the Supplemental Stranded Cost NOPR to allow a potential departing customer to receive an estimate of the customer's ''maximum possible stranded cost exposure without mitigation.'' Requiring the utility to provide an estimate that reflects the competitive market value of the capacity and associated energy to be released will better enable the customer to assess its supply options.

[872] If the customer is a retail customer contemplating becoming a wholesale transmission customer, it should specify in its request, to the extent possible, the date on which the customer is considering becoming a wholesale transmission customer of the utility and the amount of generation, if any, it will continue to purchase from its existing supplier.

[873] If the customer is a retail customer contemplating becoming a wholesale transmission customer, the utility should provide a detailed rationale justifying the basis for its reasonable expectation of continuing to provide the customer bundled retail service.

[874] Subsection (i) above also would apply to a retail customer contemplating becoming a wholesale transmission customer if the customer believes that the utility has failed to establish that it had a reasonable expectation of continuing to provide the customer bundled retail service.

stranded costs is reasonable; *or* (b) wait until the proposed stranded cost charge is filed by the utility under section 205 of the FPA, and contest it at that time.[875] In either case, because estimates of RSE and CMVE may change over time, any estimate of stranded costs provided by a utility to a customer will not be considered binding prior to any filing by either party with the Commission. However, any stranded cost estimate filed by the utility in a section 205 or 206 proceeding, or in response to a petition for a declaratory order, shall be considered to be a binding estimate of the customer's maximum stranded cost obligation for purposes of litigation. Similarly, any estimate of stranded cost obligation filed by a customer in a petition for declaratory order or a section 205 or 206 proceeding shall be considered to be a binding estimate of the customer's minimum stranded cost obligation for purposes of litigation.[876] Estimates of stranded cost obligation that are filed by either party with the Commission shall include the information, including the supporting detail, identified in (2) above.

(5) If a utility intends to file for stranded cost recovery from a customer through either a stranded cost amendment to its existing contract or a surcharge on transmission rates, it must file its stranded cost estimate no later than 120 days prior to the end of the customer's contract term. The filing shall include the information, including the supporting detail, set forth in (2) above. The customer, of course, may contest the contents of such a filing.[877]

Conditions of the Marketing/Brokering Option

A customer may choose to market or broker a portion or all of the released capacity and associated energy identified by the utility in its stranded cost estimate (or to contract with a marketing/brokering agent). Importantly, by exercising the marketing or brokering option, the customer does not relinquish its right to contest any aspect of the utility's stranded cost estimate, including whether the utility is entitled to recover stranded costs for the period that the customer has agreed to market or broker any released capacity and associated energy. To implement this option, a customer must inform the utility in writing of its decision no later than 30 days after the utility files its estimate of stranded costs for the customer with the Commission. Before marketing or brokering of the released capacity and associated energy can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount of capacity and associated energy the customer is entitled to schedule, the price of capacity and associated energy, and the duration of the customer's marketing/brokering of the released capacity and associated energy. Parties are encouraged to settle disputes over these and any other marketing/brokering implementation issues. The negotiations should be guided by the principle that the utility must allow the customer to market or broker the released capacity and associated energy under terms and conditions comparable to those for a utility resale of the capacity and associated energy to a third party. If agreement over marketing or brokering cannot be reached, the parties may seek to include the issue as a part of a proceeding initiated at the Commission with respect to the utility's stranded cost estimate for the customer.[878] Upon issuance of an order resolving the disputed issues, the customer may reevaluate its decision to exercise the marketing/brokering option. The customer also may choose to market or broker any released capacity and associated energy not being marketed or brokered under an earlier agreement with the utility. A customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

Payment for Released Capacity and Associated Energy Under the Marketing Option

If the customer chooses to market released capacity and associated energy, it shall pay the utility's estimate of the competitive market value of the capacity, or, if the marketing option is exercised after a Commission order, it shall pay the competitive market value amount as determined by Commission order. In addition, for all energy scheduled to be delivered, the customer shall pay the utility's average system variable costs. The customer may also choose to market only a portion of the released capacity and/or for a shorter period. In this situation, the customer will also pay the competitive market value for the released capacity plus the utility's average system energy costs. The customer's liability for payment of stranded costs is unaffected by its decision to market released capacity and associated energy.[879] In addition, to the extent that the customer chooses to market a portion or all of the capacity alleged by the utility to be stranded, a final determination with respect to the customer's stranded cost obligation will not affect any prior marketing agreement.

Payment for Stranded Costs Under the Brokering Option

If the customer chooses to broker a portion or all of the released capacity and associated energy, any revenue received from such brokering activity shall be used to offset the utility's estimate of the competitive market value of the brokered capacity and associated energy.[880] Once a brokering agreement is executed between the customer and the utility, if the customer's brokering efforts fail to produce a buyer within 60 days of the date of that agreement, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula.

[875] As discussed above, retail customers contemplating becoming wholesale transmission customers may use the same procedures. As also discussed above, customers under existing requirements contracts with public utilities have the option of making a filing under section 206 seeking to amend the contract to add an explicit stranded cost provision, without having to go through these procedures.

[876] Although estimates by the utility or the customer may be binding for purposes of litigation, this does not mean that the parties may not settle at any time on another amount.

[877] A customer requesting a section 211 order for transmission services from a transmitting utility also may incur a stranded cost obligation. Any estimate of stranded cost obligation resulting from the requested transmission services should be included as part of the utility's good faith response to the customer's request for transmission services. *See* 18 CFR 2.20. Because the Commission will apply the revenues lost formula to any request for stranded cost recovery as a part of its determination of the appropriate charge for transmission services ordered in a section 211 proceeding, we encourage non-public utilities to use the revenues lost formula to estimate a customer's stranded cost obligation.

[878] Because litigation of stranded costs may extend beyond the date of the customer's departure, the customer may also file a petition for a declaratory order requesting expedited resolution of marketing or brokering implementation issues.

[879] If the customer can market the released capacity and associated energy for a higher price than the customer paid for it, the customer effectively reduces its stranded cost obligation, *i.e.*, the incremental revenue received offsets a portion of the customer's stranded cost payment to the utility.

[880] For example, if the customer brokers any released capacity and associated energy for a higher price than the utility's estimated competitive market value of that capacity and energy, the difference between the utility's estimate and the brokered price will be used to increase the utility's CMVE component of the stranded cost calculation, thereby reducing the customer's stranded cost obligation.

10. Stranded Costs in the Context of Voluntary Restructuring

In the Supplemental Stranded Cost NOPR, we noted that the functional unbundling of wholesale services does not require corporate unbundling (such as disposition of assets to a non-affiliate, or establishing a separate corporate affiliate to manage a utility's transmission assets). At the same time, we indicated that some utilities may ultimately choose some form of corporate unbundling.[881] We reaffirm in this Final Rule that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by individual utilities.

11. Accounting Treatment for Stranded Costs Comments

A number of commenters ask the Commission to provide accounting treatment guidance as part of its procedures for implementing its policies on stranded costs and their recovery.[882]

NSP states that the Commission will need to provide appropriate accounting guidance for the final stranded cost recovery methodology, including accounting for any portion of stranded cost recovery representing capital costs, the effect of any interperiod differences between the stranded cost calculations and the authorized recovery period, and the effects of differences between book and income implications of the stranded cost recovery mechanism. NSP also asserts that, in addressing the accounting implications of the final rule, the Commission must consider the requirements of the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 121, ''Impairment of Long-Lived Assets'' (SFAS No 121).

NASUCA states that one of the Commission's stated goals in providing stranded cost recovery is to protect against cost shifting. NASUCA argues that the Commission should adopt an accounting rule that assures that any federal resolution of wholesale stranded costs does not impose any cost shifting to captive customers.

EEI and Centerior argue that the Uniform System of Accounts as presently configured does not support the Commission's proposed policies on stranded cost recovery. Further, EEI states that even with the revenues lost approach, which EEI supports, utilities will still have to account for their assets on a class-of-asset by class-of-asset basis. EEI argues that this is necessary to ensure that the costs of the assets are expensed in the proper accounting period. EEI states that one of the basic principles of financial accounting is that expenses should be matched with the related revenues.

Commission Conclusion

As discussed in Section IV.J.3, this rule adopts a direct assignment approach for the recovery of stranded costs from departing generation customers. Under the revenues lost approach, stranded cost recovery is limited to the departing generation customer's contribution to fixed costs that the utility otherwise would not recover because of the customer's departure.

We recognize that there are certain similarities between the financial reporting objectives of SFAS No. 121 and the determination of stranded costs. However, there are also important differences between SFAS No. 121 and our approach to stranded costs. The revenues lost approach does not attempt to identify specific uneconomic assets and is not limited to only long-lived assets. Instead, it uses a formulary methodology that encompasses all fixed costs of providing service.

From a financial accounting standpoint, our approach to stranded costs creates the potential for a mismatch between the periods in which the stranded costs are charged to expense and any revenues provided for their recovery are included in net income determinations. This is because the earning process entitling a utility to the benefits of stranded cost recovery and thereby requiring the recognition of revenue may be completed prior to the time that the stranded costs must be charged to expense under generally accepted cost recognition criteria. This circumstance in a cost-based regulated environment creates the undesirable potential for double recovery of the same cost, cost shifting, and inappropriate financial reporting.

In order to avoid this potential, utilities shall not recognize revenues intended to provide for recovery of stranded costs from wholesale requirements customers prior to the time that the stranded costs are charged to expense, unless prior Commission approval to do so has been obtained. Absent Commission approval, utilities shall defer such amounts in Account 253, Other Deferred Credits, and amortize them to Account 456, Other Electric Revenues, consistent with the period the related costs are charged to expense. Also, we will require a utility to submit its proposed accounting for stranded costs and related revenues as part of its rate filing requesting recovery of stranded costs under section 205 of the FPA.

12. Definitions, Application, and Summary

In the Supplemental Stranded Cost NOPR, the Commission described proposed amendments to our regulations to establish filing requirements for public utilities and transmitting utilities that seek stranded cost recovery. We proposed to define ''wholesale stranded cost'' as ''any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or (ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.'' We sought comments on whether this definition should encompass the situation where a wholesale requirements customer ceases to purchase power from the utility that had been making wholesale requirements sales to such customer without becoming an unbundled transmission services customer of that utility.[883]

Comments

We received numerous comments both supporting and opposing revisions to the proposed definition of wholesale stranded costs.[884] Several commenters oppose broadening the definition to include costs stranded by customers that do not become unbundled transmission service customers of the former supplier.[885] For example, EGA argues that the loss of an industrial customer that chooses to self-generate or the loss of a requirements customer as a result of a newly-created municipal system that interconnects with a transmitting utility that is not the customer's former supplier could have happened at any time. EGA states that revenues lost as a result of either

[881] FERC Stats. & Regs. ¶32,514 at 33,132.

[882] *See, e.g.*, EEI, NSP, LILCO, Central Hudson, Deloitte & Touche, Centerior.

[883] FERC Stats. & Regs. ¶ 32,514 at 33,115.

[884] EEI asks the Commission to expand the definition of stranded costs to account for the case where the Commission has proposed to address purely retail stranded costs (that is, where a state regulatory authority does not have authority to address stranded costs at the time that retail wheeling is required). However, the regulations will contain a definition of ''retail stranded costs'' to account for this case. *See* § 35.26(b)(5) of the Final Rule.

[885] *E.g.*, EGA, Direct Service Industries, Memphis.

scenario have nothing to do with regulatory reforms and should not be considered ''stranded'' costs.

Other commenters disagree.[886] Puget asserts that permitting departing generation customers to avoid paying stranded costs if they do not take unbundled transmission from their former suppliers would create an incentive for departing customers (or their new electric suppliers) to build unneeded and uneconomic new transmission lines. Puget says that it also could be a disincentive to engage in regional transmission planning and coordination because the existence of new transmission facilities needed to achieve regional reliability and efficiency may increase the likelihood that departing generation customers could import their power supplies over those new facilities and avoid paying the utility's stranded costs.[887]

Some of these commenters propose using an exit fee to collect stranded costs from a customer that does not take unbundled transmission from its former supplier, since a transmission surcharge is not available in this circumstance.[888] Other methods proposed include: (1) Conditioning Commission approval of the transmission rates or wholesale power rates charged by the transmission-providing utility upon the inclusion of a surcharge to recover the former supplier's stranded costs or upon the transmission-providing utility otherwise agreeing to guarantee the payment of the stranded costs or act as billing agent for the former supplier;[889] (2) authorizing the former supplier to levy a stranded cost charge on the transmission-providing utility (if that utility is interconnected with and has transmission contracts with the former supplier); (3) if a retail customer becomes annexed to a municipal utility and does not take unbundled transmission services from its former supplier, permitting recovery of stranded costs from the municipal utility through its jurisdictional transmission rates; or (4) requiring a public utility providing transmission service for a customer that has left its former supplier to agree, as a condition to recovery of its own stranded costs, to ensure the payment of any stranded costs incurred by the former supplier.[890]

Commenters also address the use of the terms ''legitimate, prudent, and verifiable'' in the definitions of wholesale and retail stranded costs. Several commenters suggest that the Commission's use of the word ''prudent'' could imply that utilities have to relitigate the prudence of costs that the Commission and state commissions have already approved; these commenters believe that utilities should not have to relitigate prudence.[891] Some argue that once a regulatory agency (state or federal) has allowed recovery of the costs in rates, or promised future recovery, utilities should not have to undergo a second regulatory review to recover those costs if they become stranded.[892]

Commenters recommend that the Commission address this situation by: Striking the word ''prudent'' from the definition or specifying that the prudence requirement is satisfied by previous regulatory authorization;[893] dropping the terms ''legitimate, prudent and verifiable'' from the definition and using instead ''allowed,'' ''accepted,'' or ''allowable'';[894] or adding ''or approved by state commission'' after the words ''legitimate, prudent and verifiable'' in the definitions of both wholesale and retail stranded costs.[895]

Other commenters oppose these proposals, suggesting that the prudence analysis for stranded cost purposes may involve questions of prudence different from those that arise in a ratemaking context.[896] DE Muni objects that replacing ''legitimate, prudent and verifiable'' with ''allowed, accepted, or allowable'' could enable a utility to recover costs that the utility may not be able to prove were prudent, legitimate, and verifiable.

A number of commenters submit that ''legitimate, prudent and verifiable'' costs should not include the costs of uneconomic plants or costs resulting from utilities' independent business decisions (as distinguished from costs the utility was forced by regulation to incur).[897]

Several other commenters address the rule's application to wholesale requirements customers.[898] AMP-Ohio asks the Commission to clarify that the reference to ''wholesale requirements customer'' is to a full requirements customer, not a partial requirements customer. It says that no transmission provider should have any reasonable expectation of continuing to serve loads of partial requirements customers. TAPS suggests that references to ''new wholesale requirements contract'' in proposed § 35.26(c)(1) should be conformed to the defined term ''new contract'' in proposed § 35.26(b)(7). In addition, it suggests that the Commission clarify the regulations by clearly foreclosing stranded cost claims for ''new contracts'' without express exit fees, instead of simply failing to provide for such recovery.

Commission Conclusion

We will retain the definition of ''wholesale stranded cost'' proposed in the Supplemental Stranded Cost NOPR.[899] We believe it would be inappropriate to expand the definition to include the situation where a

[886] *E.g.*, Atlantic City, Carolina P&L, Consumers Power, Minnesota Power, Knoxville, Alma, Florida Power Corp, El Paso, Central Louisiana, Southern, WP&L, FL Com, Utility Investors Analysts, Florida Power Corp, El Paso, Central Louisiana, TDU Systems, NW Conservation Act Coalition, Puget, NU, EEI.

[887] Several commenters also ask the Commission to expand the definition of wholesale stranded cost to include the situation where a wholesale supplier loses wholesale load as a result of a requirements customer's loss of retail load because of retail wheeling, municipalization or retail taps from another utility's system. *E.g.*, Utilities For Improved Transition, Montaup, SC Public Service Authority. In addition, a number of commenters ask the Commission to treat the members of a single G&T cooperative system as a single economic unit and to revise the definition of wholesale stranded costs to allow a transmitting G&T cooperative (the arm of the cooperative system that provides the transmission) to recover the costs stranded when a retail customer of one of its member distribution cooperatives takes advantage of the open access environment by becoming a wholesale entity. *E.g.*, Big Rivers EC, NRECA, Tri-County EC, TDU Systems.

[888] *E.g.*, Carolina P&L, NU, Florida Power Corp, PSNM, Southern, Mountain States Petroleum Assoc, FL Com.

[889] In its reply comments, Memphis Light objects to the proposal that the Commission condition approval of all new power contracts for those customers that leave a utility's system without using the transmission services of the original utility upon the inclusion of a provision to recover the stranded cost for the previous power supplier. It argues that this proposal could result in nonrecovery from some customers because wholesale customers faced with such a provision would pursue non-jurisdictional contracts and/or generate within the confines of their own systems.

[890] *E.g.*, EEI, El Paso, NU, Atlantic City, PG&E, Coalition for Economic Competition, NW Conservation Act Coalition, Puget, NRECA, Cajun, East Kentucky, FL Com, Associated EC, Utilities For Improved Transition, TDU Systems, TVA.

[891] *E.g.*, EEI, NSP, Arizona, United Illuminating, Entergy, SCG&E, PECO, NRECA.

[892] *E.g.*, EEI, Centerior, NSP, SCG&E, PECO, Tucson Power, Arizona.

[893] *E.g.*, PECO, Entergy.

[894] *E.g.*, EEI, SCG&E, Carolina P&L.

[895] *E.g.*, Atlantic City. EEI also proposes that at the time of filing of a stranded cost recovery charge (whether as an amendment to a contract or a surcharge to a transmission rate), the Commission limit its inquiry to the issue of the stranded cost charge rather than allowing all aspects of a rate or contract to be opened up. EEI states that this is what the Commission did in the natural gas context, where it permitted limited rate filing cases under section 4 of the NGA.

[896] *E.g.*, Alcoa, Cleveland.

[897] *E.g.*, Mountain States Petroleum Assoc, Caparo, Torco.

[898] *E.g.*, AMP-Ohio, PA Munis, TAPS.

[899] For the reasons articulated below, we accordingly will reject the various revisions to the definition that were proposed by commenters.

wholesale requirements customer[900] (or a retail-turned-wholesale customer) ceases to purchase power from the utility without using the transmission services of that utility.[901] Any costs that the utility might incur as a result of the loss of the requirements customer in this scenario would be outside the scope of this Rule. The premise of this Rule is that, where a customer uses the new open access to obtain power from a new generation supplier, the customer must pay the costs that were incurred on its behalf under the prior regulatory regime. However, if a customer leaves its utility supplier by exercising power supply options (such as access to another utility's transmission system or self-generation) that do not rely on access to the former seller's transmission, there is no nexus to the new open access rules.[902] If a customer is able to obtain power from a new supplier by using the transmission system of another utility, it is likely that the customer could have made these arrangements in the absence of the new open access rules. The new transmission provider would have had little incentive to deny transmission services to the customer in order to protect an existing power supply arrangement, since it was not the customer's power supplier in the first place. Indeed, it is likely that the neighboring utility would have a positive incentive to provide the transmission service in order to increase its revenues. This incentive is unchanged by open access transmission.

Some commenters have asked us to eliminate the term ''prudent'' from the definition of stranded costs. We will not do so; we will retain the requirement that stranded costs be ''legitimate, prudent and verifiable.'' A determination that a utility had a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. Prudence of costs, depending upon the facts in a specific case, may include different things: *e.g.,* prudence in operation and maintenance of a plant; prudence in continuing to own a plant when cheaper alternatives become available; prudence in entering into purchased power contracts, or continuing such contracts when buy-outs or buy-downs of the contracts would result in savings. The Commission therefore cannot make a blanket assumption that all claimed stranded costs will have been prudently incurred. However, we clarify that we do not intend to relitigate the prudence of costs previously recovered.[903]

Thus, this Rule will permit a public utility or transmitting utility to seek recovery of wholesale stranded costs as follows. First, for stranded costs associated with new wholesale requirements contracts (that is, any wholesale requirements contract executed after July 11, 1994), the regulations will allow recovery of stranded costs only if the contract contains an explicit stranded cost provision that permits recovery. By ''explicit stranded cost provision'' we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate.. We clarify that provisions in requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that explicitly reserved the right to stranded cost recovery pending the outcome of this Rule will be deemed ''explicit stranded cost provisions.'' However, provisions in requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that postpone the issue of stranded cost recovery without specifically providing for recovery of stranded costs will not be considered ''explicit stranded cost provisions.''

Second, for existing wholesale requirements contracts (that is, any wholesale requirements contract executed on or before July 11, 1994), a utility may not recover stranded costs if recovery is explicitly prohibited by the contract (including associated settlements) or by any power sales or transmission tariff on file with the Commission.

Third, for existing wholesale requirements contracts that do not address stranded costs through exit fee or other explicit stranded cost provisions, a public utility may seek recovery of stranded costs only as follows: (1) If the parties to the existing contract renegotiate the contract and file a mutually agreeable amendment dealing with stranded costs, and the Commission accepts or approves the amendment; (2) if either or both parties seeks an amendment to the existing contract under sections 205 or 206 of the FPA, before the contract expires, and the Commission accepts or approves an amendment permitting stranded cost recovery; or (3) if the public utility files a request, before the contract expires, to recover stranded costs through a departing generation customer's transmission rates under FPA sections 205–206 or 211–212.

Fourth, if the selling utility under an existing wholesale requirements contract is a transmitting utility but not also a public utility, and the contract does not address stranded costs through an explicit exit fee or other stranded cost provision, the transmitting utility may seek to recover stranded costs through a surcharge to a departing generation customer's transmission rates under FPA sections 211–212. Such utility may not seek recovery of stranded costs through a section 211–212 transmission rate if the existing requirements contract does contain an explicit exit fee or other stranded cost provision.

Fifth, for a retail-turned-wholesale customer, a public utility or transmitting utility may file a request to recover stranded costs from the newly-created wholesale customer through that customer's transmission rates under FPA sections 205–206 or 211–212.

Sixth, for customers who obtain retail wheeling, a public utility or transmitting utility may seek recovery through Commission-jurisdictional transmission rates only if the state regulatory authority had no authority under state law to address stranded costs when retail wheeling is required.

[900] ''Wholesale requirements contract'' is defined as ''a contract under which a public utility or transmitting utility provides *any portion* of a customer's bundled wholesale power requirements'' (emphasis added). Thus, a ''wholesale requirements customer'' for purposes of the Rule can be either a full or a partial requirements customer. We reject AMP-Ohio's suggestion that the Commission make a blanket finding that a utility could not have had a reasonable expectation of continuing to serve a partial requirements customer. For example, a partial requirements customer may have met part of its needs with its own generation but because it could not build more of its own generation locally it had to depend on the utility for the remainder of its needs in the absence of the new open access. Also, a partial requirements customer may have been able to reach alternative suppliers for only a portion of its requirements due to transmission constraints. If this were the case, the partial requirements supplier may well have had a reasonable expectation of continuing to serve the balance of the customer's load.

[901] The definition of ''retail stranded cost'' contains a similar requirement (*i.e.*, the retail customer must become, in whole or in part, an unbundled retail transmission services customer of the public utility or transmitting utility from which the customer previously received bundled retail services). We will retain it for the same reasons discussed above.

[902] As we have said, this Rule is not intended to insulate a utility from the normal risks of competition.

[903] As the Commission has previously indicated, however, in the case of formula rates, approval of a formula rate constitutes approval of the formula, and not the underlying costs. *See, e.g.*, New England Power Company, *et al.*, 72 FERC ¶61,148 at 61,761 (1995); Boston Edison Company, Opinion No. 376, 61 FERC ¶61,026 at 61,145 (1992).

K. Other

1. Information Reporting Requirements for Public Utilities

In the NOPR, the Commission did not propose any changes to its information filing requirements for public utilities.

Comments

Many IOUs argue that the current information filing requirements competitively disadvantage traditional public utilities and unfairly benefit sellers, such as power marketers, that are not required to provide comparable information.[904] They urge the Commission to eliminate the requirement for public disclosure of competitively sensitive, proprietary, or otherwise confidential Form No. 1 data. They contend that requiring such disclosure only from traditional public utilities harms such public utilities and compromises the development of efficient competition. Illinois Power asks the Commission to review all information that utilities must file, including EIA 860, EIA 767, and FERC Form No. 715.

A number of commenters believe that some type of information requirement must also be placed on non-public utility entities.[905] PacifiCorp suggests that the Commission should require transmitting utilities that do not file a Form No. 1 to file similar information annually with the Commission. Ohio Edison asserts that the Commission should extend its use of the reciprocity concept to require the filing of operating data with the Commission. Further, if non-public utility entities are not required to disclose certain information, Ohio Edison asserts that all public utilities that have received approval to sell power at market-based rates, including traditional utilities, should also be free from having to disclose such information.

Arizona argues that enforcing comparability vis-a-vis non-public utility transmitting utilities would seem to invite jurisdictional challenge. Thus, it would support legislation to broaden the Commission's jurisdiction.[906]

Commission Conclusion

We will not adopt the suggestion made by a number of commenters that we now eliminate the public disclosure of allegedly competitively sensitive, proprietary, or otherwise confidential data submitted to the Commission on Form No. 1, as well as on other Commission forms. The information that we collect from public utilities is necessary to carry out our jurisdictional responsibilities and is used, among other things, to evaluate the reasonableness of cost-based rates subject to our jurisdiction and the operation of power markets.[907] Moreover, as we explained in *ConEd*,

> [R]eports required to be submitted by Commission rule and necessary for the Commission's jurisdictional activities are considered public information. 18 CFR 388.106. In addition, the Commission has long required jurisdictional utilities to submit Form 1 data on a form that states on its cover that the Commission does not consider the material to be confidential.[908]

We are sensitive to the lack of symmetry in the generation information we require from traditional public utilities, particularly those that have market-based rate authority, and the generation information we require from other public utilities (*e.g.*, public utility marketers) authorized to sell at market-based rates.[909] However, the record in this proceeding is insufficiently developed for us to make and support a well-informed decision requiring a different reporting scheme, particularly given the industry's current rapid pace of change. Also, we are not persuaded that the burdens borne by traditional public utilities (primarily annual reports submitted months after-the-fact) are impairing the competitiveness of these utilities so much that we must act hastily now, instead of deferring a decision to a more appropriate proceeding. Moreover, we are required to regulate the rates of public utilities and, although we are moving toward greater reliance on market-based generation rates, we continue to regulate generation on a cost basis for most traditional public utilities, particularly rates for sales from existing generation. To assure that these rates are just and reasonable, we, as well as the customers of public utilities, need the more detailed information our regulations require public utilities to submit.

Accordingly, at this time, we will not change our information reporting requirements. As the industry becomes more competitive, we will monitor our reporting requirements to make sure that they are needed, fair to all segments of the industry, and consistent with the workings of a competitive environment.

2. Small Utilities

In the NOPR, we did not address whether special provisions were needed for small public utilities and small transmission customers because of the possible burden of unbundling, open access tariffs, and the OASIS requirement.

Comments

A number of commenters assert that the unbundling requirement poses significant problems for smaller public utilities and that small utilities should not be subject to the same requirements as larger utilities.[910] St. Joseph notes that in small utilities one system operator typically runs the system operations center. Functional unbundling, it asserts, would require the addition of another operator for each shift at great cost to the small utility. Central Hudson estimates that unbundling would result in an approximately 10 percent increase in the wholesale price, putting small utilities at a competitive disadvantage.

Several commenters assert that many small utilities enjoy little or no transmission market power because their systems tend to be in parallel with large systems and are bypassed as a result. They say that customers prefer to deal with one large regional utility rather than pay pancaked transmission rates for service through two or more small utilities.

Citizens Utilities argues that some systems are radial spurs of much larger systems and merely serve to link points of interconnection. It claims that a network tariff is not applicable in such a case and that it is unlikely that third parties would request service over such small or isolated systems. It recommends that if a utility is basically a spur system and faces little present or future demand for third-party service, the Commission should either relax the open access requirements or defer them until a section 211 request is submitted.

East Kentucky proposes that the Commission exempt not-for-profit utilities from the requirement to separate the functions related to operation and marketing, since small G&T cooperatives exist solely to serve the needs of their owner-member distribution cooperatives.

[904] *E.g.*, NIPSCO, Illinois Power, Centerior, Ohio Edison, EEI.

[905] *E.g.*, NSP, Ohio Edison.

[906] *See also* Minnesota P&L.

[907] *See, e.g.*, Consolidated Edison Company of New York, Inc. and Central Hudson Gas & Electric Corp., 72 FERC ¶ 61,184 at 61,891 (1995) (*ConEd*).

[908] 72 FERC at 61,891.

[909] We note that public utility marketers are required to file quarterly transaction reports so that the Commission can monitor the reasonableness of their charges and their ability to exercise market power. *See* Heartland Energy Services, Inc., 68 FERC ¶ 61,223 at 62,065–66 (1994). Unlike traditional public utilities, marketers do not use cost-based rates. Approval of the generation rates of non-jurisdictional transmitting utilities is not subject to our jurisdiction.

[910] *E.g.*, Central Hudson, Central Illinois Light, CVPSC, Citizens Utilities, East Kentucky, IPALCO, Montana-Dakota Utilities, Seattle, St. Joseph, Tallahassee, VT DPS.

VT DPS suggests that waiver of marketing and transmission personnel separation requirements may be appropriate in the case of smaller utilities that do not operate control areas. St. Joseph proposes that the Commission establish a threshold level based on system demand of 1000 MW, below which unbundling of wholesale transmission functions from other dispatching functions would not be required. Alternatively, St. Joseph proposes an exemption from unbundling where the utility can demonstrate that it has no market power and that unbundling would not materially improve the level of competition in the generating market.

Central Hudson believes that the Commission should allow the development of a short form tariff or else defer the functional unbundling requirement for smaller utilities and use the section 211 process in the interim to provide flexibility for these utilities.

Oregon Trail EC, a small rural electric, public utility cooperative, requests that the Commission revise proposed § 35.28 of its regulations to provide that the generic open access transmission requirements apply only to public utilities that *operate* facilities used for the transmission of electric energy in interstate commerce. It explains that it owns one transmission line that it leases to BPA, which operates the line as part of its integrated transmission network. Thus, Oregon Trail EC states that it cannot meet the requirements of the open access rule. It also points out that the Commission exempted Oregon Trail EC and other similarly situated utilities from the transmission reporting requirements of Form No. 715 because they did not engage in transmission planning.

ALCOA suggests that the default tariffs for smaller utilities with transmission systems unlikely to be used by others should not become effective automatically. Rather, the default tariffs should become effective only when service is requested. Citizens Utilities suggests that relaxed tariff requirements be established for small utilities with insignificant demand for transmission service.

BG&E believes that a utility using its system on a network basis for economic dispatch should not be required to file a network service tariff if there is no customer to take the service. It suggests that if municipalization were to occur, the Commission could then require the utility to file, within 60 days, a network service tariff to serve the new municipal.

Commission Conclusion

We are sympathetic to the array of concerns raised by small public utilities and small transmission customers. The regulations we are adopting include waiver provisions under which public utilities and transmission customers, and non-public utility entities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations or for special treatment.[911] However, it is difficult to imagine any circumstance that would justify waiving the requirements of this Rule for any public utility that is also a control area operator.

We recognize, for example, that it might be a financial burden on small public utilities to unbundle generation from transmission, follow standards of conduct that separate transmission personnel from wholesale marketing personnel, and maintain an OASIS. These requirements may be particularly burdensome for small public utilities that own no generation and buy at wholesale on a radial transmission line from another utility's grid. In addition, if a small public utility's service territory is part of another utility's control area, the small public utility should be permitted to make a showing that it should be exempt from all or some of the Rule. In this circumstance, we will consider granting a waiver if the utility can show that: (1) It does not own transmission facilities, (2) it has turned control of its facilities over to someone else (such as the control area operator) who complies with the rule as its agent, or (3) no one is likely to ask to use its facilities (*e.g.,* because they are radial lines), and it commits to file an open access tariff within 60 days of a request to use its facilities and to comply with the rule in all other ways.

Because the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and we will require applications and fact-specific determinations in each instance. We note here that any waivers that we may grant depend upon the facts presented in each case. If the circumstances that give rise to the exemption change, the waiver may no longer be appropriate. For example, a radial line today could very easily become part of a network tomorrow and a portion of a grid that no one is interested in using today could become an important transmission link tomorrow, especially if retail access is allowed.

In addition, we will apply the same standards to any entity seeking a waiver. This includes public utilities seeking waiver of some or all of the requirements of the rule, as well as non-public utilities seeking waiver of the reciprocity provisions contained in the pro forma open access tariff. Thus, we would not apply the open access reciprocity provision to small non-public utilities that are not control area operators and either do not own or control transmission or have transmission that no one is likely to ask to use. They would not have to provide an open access tariff, establish an OASIS, or separate operators of transmission from wholesale purchasers in order to satisfy the reciprocity condition for obtaining transmission service. However, they will have to apply for this waiver and demonstrate that they qualify for the waiver.

3. Regional Transmission Groups

In the NOPR, we again expressed our support for the voluntary formation of regional transmission groups (RTGs).[912] We also explained that the potential benefits of RTGs would not be undermined by the rules proposed in the NOPR.

a. Incentives for RTGs to Form and Resolve Regional Transmission Issues

Comments

A number of commenters urge the Commission to provide incentives for the formation of RTGs within two years of the adoption of the final rule.[913] Several commenters argue that the Commission should encourage a regional approach to transmission issues by expanding the role of RTGs.[914] Com Ed also claims that contract path pricing problems probably will need to be resolved at the regional level.

Sierra Pacific Power, which views open access as the major benefit of RTGs, questions the need to provide incentives for the development of RTGs once open access is implemented. However, it does see that RTGs may help promote open access with non-public utility entities, who have shown

[911] Non-public utility entities could request that the Commission find that they can satisfy the reciprocity condition without meeting all or some of the requirements that public utilities must meet. The requests could encompass a wide variety of circumstances. For example, a non-public utility could agree to offer comparable transmission services but not wish to have an OASIS or separate transmission personnel from wholesale marketing personnel due to the cost of doing so. The Commission could find that the entity nevertheless satisfied the reciprocity condition.

[912] FERC Stats. & Regs. ¶ 32,514 at 33,095.

[913] *E.g.,* AMP-Ohio, Missouri Joint Commission, MT Com, WEPCO, Nebraska Public Power District, Texas-New Mexico.

[914] *E.g.,* WEPCO, Portland, WA Com.

an increased interest in joining RTGs. American Wind and MT Com request that the Commission adopt policies that will encourage a close working relationship between RTGs and state authorities.

Otter Tail contends that the final Rule should stop short of establishing any conditions on the formation, governance, or functions of RTGs, arguing that such issues are complex and outside the scope of the NOPR. ALCOA and Missouri Joint Commission encourage the Commission to make certain that its policy regarding RTGs is not implemented in a manner that conflicts with the new open access regime.

Commission Conclusion

We continue to support the development of RTGs and encourage the formation of regional tariffs.[915] In our Policy Statement Regarding Regional Transmission Groups, we first explained our support for such voluntary associations.[916] We again explained our support in the NOPR:

> We believe that RTGs can speed the development of competitive markets, increase the efficiency of the operation of transmission systems, provide a framework for coordination of regional planning of the system and reduce the administrative burden on the Commission and on members of RTGs by providing for voluntary resolution of disputes.[917]

To further encourage the development of RTGs, we will accept regional open access transmission tariffs developed by RTGs that are consistent with the objectives of this Rule. This should make it easier for all parties in a region to coordinate their activities.

b. Deference to RTGs To Develop Regional Tariffs and Prices

Comments

A number of commenters urge the Commission to give considerable deference to RTGs on such issues as the formulation of pricing methods and RTG member duties.[918] Nebraska Public Power District requests that the Commission consider permitting a megawatt-mile pricing mechanism for MAPP. NWRTA urges the Commission to define clearly how much deference it will accord to RTGs and explicitly grant deference to RTGs on such matters as dispute resolution and decisionmaking processes. It also asks that the Commission honor the reciprocity provisions related to Canadian participation that are contained in the NWRTA agreement. Nevada Power requests the Commission to accept, as not unduly discriminatory, RTG open access tariffs that reflect the members' specific terms and conditions so long as the tariffs satisfy the substantive requirements of the final rule. It proposes that such tariffs be allowed to become effective without hearing or refund obligation.

Texas-New Mexico, while encouraging deference to RTGs in general, argues that deference must be conditioned upon a requirement that the RTG provide not only equal access but also terms and conditions of service that are comparable to what a customer could otherwise obtain under the final Rule tariff or under section 211 of the FPA.

Southwest TDU Group contends that RTGs should not be given deference, and RTG filings should be subject to the same standards and scrutiny as non-RTG filings.

Commission Conclusion

As we explained in the RTG Policy Statement, we intend to give deference to the planning, dispute resolution, and decisionmaking processes of an RTG. With respect to pricing proposals submitted by RTGs, we believe that RTGs may be able to develop solutions to such problems as loop flows through innovative flow-based pricing methodologies. As we stated in the Transmission Pricing Policy Statement, we will afford considerable deference to an RTG.

4. Pacific Northwest

Comments

Commenters in the Pacific Northwest ask the Commission to be flexible in reviewing tariffs that are based on regional practices, and that differ from the final Rule tariff as a result. Public Generating Pool urges the Commission to recognize that the Northwest's transmission system has been developed and is operated to support the region's coordinated power system. That is, it wants all hydro spill to be treated equally with no preference between federal and non-federal power. Also, it asserts that firm available transmission capacity in the Northwest must be worked out by the NWRTA RTG to account for the contingent operation of generation to avoid hydro spill.

Similarly, other commenters note that the Northwest's integrated transmission system was constructed to support a unique regionwide hydroelectric-dependent generating system and that flexibility is needed to accommodate the characteristics of the system.

WA Com argues that imposition of a uniform national tariff would not reflect the region's specific system characteristics or operating practices. It argues that the final Rule could impede rather than promote efficient competition in the Northwest. It believes that the Commission should defer to RTGs for defining and implementing wholesale transmission access terms and conditions at the regional level.

The Washington and Oregon Energy Offices, while supporting the adoption of regional practices, argues that uniform transmission principles should apply for all transmitting entities in the region. They argue that dispatch decisions are complicated by flood control, salmon passage, navigation, irrigation, and other constraints. Puget requests that the Commission give each transmitting utility the flexibility to file tariffs that fit unique or unusual circumstances and allow for regional market differences.

Because the terms and conditions offered by the smaller transmission owners in the Northwest are determined by the terms and conditions offered by Bonneville, Pacific Northwest Coop argues that the terms and conditions for wholesale power transmission, ancillary services, and RINs should be deferred until BPA's 1996 rate case is resolved and until appropriate regional and national systems and protocols are developed.

Commission Conclusion

As we explained with respect to RTGs, we encourage the filing of regional open access transmission tariffs.[919] The Final Rule pro forma tariff contains provisions allowing utilities to modify tariff terms to reflect prevailing regional practices. This should permit entities in the Pacific Northwest to address unique circumstances that exist in the Pacific Northwest and to incorporate prevailing regional practices (*e.g.,* treatment of hydropower generation in the priority of dispatch) into their open access transmission tariffs.[920] This should also encourage

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[915] If an RTG is not a corporate person, each utility member of the RTG may file the same or complementary tariffs.

[916] 58 FR 41626 (August 5, 1993), FERC Stats. & Regs., Regulations Preambles ¶ 30,976 (RTG Policy Statement).

[917] FERC Stats. & Regs. ¶ 32,514 at 33,095.

[918] *E.g.,* UT Com, ID Com, LA DWP, Nebraska Public Power District, Salt River, Nevada Power. *See also* NEPCO, United Illuminating, Utility Working Group.

[919] Also, as we explained with respect to RTGs, we will review pricing proposals in regional tariffs pursuant to our Transmission Pricing Policy Statement.

[920] This Rule will not resolve disputes over federal hydro preference policies or over the agreements incorporated in the Northwest Power Planning Act.

other regional solutions, such as the development of regional ISOs, to transmission problems.

In addition, although we will put the Final Rule pro forma tariff (which already allow for certain provisions consistent with regional practices) into effect for all public utilities 60 days after publication of this Rule in the Federal Register, utilities may file regional tariffs or propose deviations in the pro forma tariff based on additional regional needs to be effective at any time thereafter. Such proposals, however, will have to be consistent with the requirements of the Final Rule and be reasonable, generally accepted in the region and consistently adhered to by the transmission provider. Further, we will not permit entities in a region to claim different sets of prevailing regional practices.

5. Power Marketing Agencies

a. Bonneville Power Administration (BPA)

Comments

Washington Water Power explains that for open access transmission to be fully realized in the Pacific Northwest there must be federal legislation to remove the monopoly protections of federally generated power. Until then, Washington Water Power suggests certain mitigating measures that would increase competition in the Pacific Northwest. It also urges the Commission to take BPA's special characteristics into account in issuing the final rule.

Public Power Council encourages the Commission to make broad use of section 211 to mandate transmission access to ensure that BPA continues to provide comparable open access transmission.[921]

Public Generating Pool argues that the extent to which BPA's tariffs are allowed to deviate from the rule should be governed by the technical characteristics of the system and not by BPA's status.[922]

Direct Service Industries argues that the non-discrimination standard is made applicable to BPA by section 212(i) and that the Commission has the authority to review all BPA rates under the Northwest Power Act (citing Pacific Northwest Electric Power Planning and Conservation Act, section 7(a), 16 U.S.C. 839e(a)). It also argues that functional unbundling is particularly important for BPA because of BPA's market power and relative freedom from regulation. Clark also argues that the Commission should require BPA to meet the comparability standard. It alleges that BPA refuses to provide comparable service. It asserts that the Commission has authority to remedy the problem under the Energy Policy Act amendments to section 212, which Clark states gives the Commission authority over BPA's transmission practices. Clark also notes that BPA is a member of WRTA and, as such, must provide comparable service.

Pacific Northwest Coop argues that many of the issues presented in this rulemaking are currently being contested in the BPA rate case in Docket Nos. WP–96/TR–96 and TC–96. It says that the Commission should defer application of the rule to Pacific Northwest Coop and all of BPA's customers until conclusion of the rate case.

Washington and Oregon Energy Offices asserts that it would be proper for the Commission ''to impose similar transmission price structures upon Bonneville under section 211 orders as it will for jurisdictional [public] utilities under sections 205, 206, and the NOPR.''

With respect to stranded costs, BPA notes that it may be necessary to tailor a stranded cost policy for BPA that addresses the goals of open access and wholesale stranded cost recovery in a manner consistent with BPA's unique circumstances. BPA asks the Commission to defer consideration of its stranded investment and related cost recovery issues until it makes a rate filing with the Commission.[923] It further argues that the rule should not address whether and how BPA stranded costs might be recovered in transmission rates approved by the Commission under authority other than sections 211 and 212. Clark argues that the Commission's stranded cost recovery policy is inapplicable to BPA.

NW Conservation Act Coalition makes the following suggestions: (1) The Commission should grant BPA the authority to levy exit fees on customers who are terminating service and who do not use BPA's transmission system for their new power transaction; (2) any affected person should be allowed to petition the Commission for review of BPA's rates for inadequate or inappropriate mitigation of its stranded benefits; (3) the rule should insist upon a requirement that open access and stranded cost recovery be permitted only if the entities involved can show there will be no lessening of support for public purposes; and (4) the Commission should clarify that the Direct Service Industries customers are retail customers and that they will be subject to recovery of stranded costs and benefits.

Commission Conclusion

BPA is not a public utility under section 201(e) of the FPA and, thus, is not subject to the requirements of this Rule to put the Final Rule pro forma tariff into effect. However, there are three circumstances under which the Commission may review BPA's transmission access and pricing policies. First, BPA could file an open access tariff and accompanying rates for review and confirmation under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[924] and at that time could ask the Commission to find that its tariff meets the Commission's open access policies. Second, BPA is a transmitting utility subject to a request for mandatory transmission services under section 211 of the FPA. Transmission required of BPA under section 211 would have to be consistent with the requirements imposed on BPA under its organic statutes, the Northwest Power Act, and the Federal Columbia River Transmission System Act.[925] Third, if BPA receives open access transmission from a public utility, it is subject to the reciprocity provision contained in the utility's Final Rule pro forma tariff. If BPA seeks to comply with the reciprocity provision, it could use the declaratory order procedures we have provided in this rule for non-public utility transmission providers. Finally, we note that BPA has agreed to provide open access as a member of two RTGs approved by this Commission.

With respect to stranded costs, BPA has asked us to clarify that the Stranded Cost Rule does not address whether and how BPA stranded costs might be recovered in transmission rates approved by the Commission under authority other than sections 211 and 212 of the FPA (namely, section 7 of the Northwest Power Act). We clarify that this rule addresses only stranded costs recovered by public utilities under the FPA and transmitting utilities (including BPA) that are subject to mandatory transmission requests under FPA section 211. It does not address stranded cost recovery by BPA under the Northwest Power Act.

[921] *See also* Puget, Portland, Reynolds.

[922] *See also* Public Power Council.

[923] *See also* Snohomish, NPPC, W&O, Public Power Council, Washington and Oregon Energy Offices, Direct Service Industries.

[924] 16 U.S.C. 839–839h.

[925] 16 U.S.C. 838–838j.

b. Other Power Marketing Agencies

Comments

SEPA requests that the final rule assure that SEPA can receive network transmission service when necessary. It also indicates that it has 58 customers that receive less than one MW of power, but that the NOPR pro forma point-to-point tariff contains a one MW minimum scheduling requirement. Thus, it requests that the final rule allow some flexibility with respect to this requirement so that it can carry forward its marketing program.

DOE notes that the Western Area and Southwestern Area Power Administrations have pledged to offer transmission services that are comparable to those required of public utilities to the extent not otherwise prohibited by law.

Commission Conclusion

Federal power marketing agencies (PMAs) are not public utilities as defined under section 201(e) of the FPA and, thus, are not required by this rule to file non-discriminatory open access transmission tariffs.[926] However, to the extent a PMA receives open access transmission service from a public utility, it is subject to the reciprocity provisions in the utility's pro forma tariff.[927] If a PMA seeks to comply with the reciprocity provision, it can file a proposed tariff and seek a declaratory ruling.

With respect to SEPA's concern that the proposed point-to-point tariff has a one MW minimum scheduling requirement, but many of its customers have loads of less than one MW, we clarify that the Final Rule pro forma tariff will allow SEPA to continue to schedule service for these customers. Under SEPA's current transmission arrangements, it is allowed to aggregate loads within a single control area that are less than one MW individually, but jointly are more than one MW, to meet the requirement at an interface. The revised language in the Final Rule tariff permits this practice to continue. We also clarify that SEPA, as a seller of power to multiple purchasers inside several control areas, is eligible to receive network service.

6. Tennessee Valley Authority

Comments

TVA is concerned that the final rule may place TVA at a disadvantage because its opportunities to participate in the electricity market outside the TVA area are so severely limited by statute. It explains that it is restricted from directly participating in the new competitive landscape except through limited power exchange opportunities with a few neighboring systems. It urges the Commission to recognize these circumstances in the final rule. TVA is also concerned that its regional customers may face stranded costs because its ability to mitigate those costs by making replacement sales to new customers is limited.

Commission Conclusion

TVA is not a public utility under section 201(e) of the FPA and, thus, is not required to file a non-discriminatory open access transmission tariff under this rule.[928]. However, if TVA receives open access transmission service from a public utility, it is subject to the reciprocity provision in the utility's pro forma tariff. If TVA seeks to comply with reciprocity, it may avail itself of the Commission's reciprocity safe harbor approach, through a declaratory ruling, if it is fearful that a public utility may deny it service simply on a claim that TVA's non-discriminatory open access tariff is not satisfactory.[929] The details of this safe harbor procedure are set forth in Section IV.G.4.f.

7. Hydroelectric Power

Comments

Non-Firm Transactions

ID Com believes that the NOPR unfairly discriminates against hydro-based utilities. It argues that utilities that rely heavily on hydropower need to engage in non-firm market transactions that depend on water levels; *e.g.,* during low water years, a utility must have access to the transmission system to make non-firm, off-system purchases. It asserts that the NOPR treats non-firm sales and purchases as subordinate to firm transactions and does not allow the utility to reserve capacity for its critical, but non-firm, transactions. ID Com also asserts that the NOPR would, in effect, strand the utility's investment in the production plant being used to generate power for the non-firm sales.

Idaho complains that the NOPR unfairly allows a customer to buy and reserve firm transmission rights surplus to its needs, but does not permit a utility to do the same. It explains that this problem is particularly acute for hydro utilities and argues that they must be allowed to reserve at tariff rates at least a portion of available transmission capacity for firm and non-firm wholesale transactions. In the alternative, Idaho asserts that the transmission owner should not be required to provide point-to-point service for transmission uses other than from demonstrated firm obligations.

Commission's Licensing Practices

National Hydropower argues that in light of the NOPR the Commission should reexamine the manner in which it exercises its FPA Part I authority with respect to (1) economic feasibility determinations, (2) section 10(a) findings, (3) determinations of section 10(j) recommendations, and (4) section 13. For example, it states that the NOPR suggests that all future electric resource selection decisions should be based exclusively on short-run marginal cost comparisons. Because, it asserts, hydroelectric power provides many public interest benefits not susceptible to precise quantification, the Commission should clarify how non-price factors are to be considered in a post-final rule wholesale electric marketplace.

Commission Conclusion

Non-Firm Transactions

As we explained above with respect to the Pacific Northwest, we will permit entities to incorporate prevailing regional practices (*e.g.,* treatment of hydropower generation in the priority of dispatch) into regional open access transmission tariffs. This should permit entities in a region to resolve concerns over the scheduling of non-firm hydropower. In addition, if a utility and its customers can agree on the scheduling of non-firm hydropower and the disruption of firm transactions, we would permit that resolution to be incorporated into the utility's tariff. Utilities are permitted to consider seasonal variations in hydropower availability in the determination of Available Transmission Capacity to be posted on the OASIS.

Commission's Licensing Practices

The issues raised by National Hydropower with respect to our

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[926] PMAs, however, are transmitting utilities subject to requests for mandatory transmission services under section 211 of the FPA.

[927] *See* Section IV.G.4.f.

[928] TVA, however, is a transmitting utility subject to requests for mandatory transmission services under section 211 of the FPA.

[929] We recognize that sections 212(f)(1) and 212(j) of the FPA, as amended by the Energy Policy Act, limit the applicability of section 211 to TVA, but conclude that this limitation in no way affects our application of the reciprocity requirement to TVA. Limitations on TVA's authority to market power are not the product of this rule but rather of TVA's enabling legislation. Thus, it is for Congress to decide whether TVA should be permitted greater marketing authority. As noted in our earlier discussion of reciprocity, TVA is not being required to file an open access tariff. Rather it is being precluded from taking advantage of benefits available under this rule without providing comparable use of its system to others.

hydroelectric licensing practices are beyond the scope of this rulemaking. Indeed, National Hydropower has already raised its concerns in a petition to the Commission to revise our hydroelectric licensing procedures, filed on July 10, 1995. That is the proper proceeding in which to address our hydroelectric licensing practices.

8. Residential Customers

Comments

Several commenters are concerned that the rule may undermine the financial position of public utilities so that they will not be able to provide many of the programs that benefit low-income residents (*e.g.*, assistance to low-income and elderly consumers, weatherization and energy conservation programs, and payment of taxes that provide many city services).[930]

La Raza is concerned that the rule will permit large preferred customers to opt out of the regulated structure, leaving behind a smaller and less affluent base to support the long-term investments made under the previous regulatory environment.

Home Builders is concerned that utilities may compensate for reduced profits under the proposed rule by raising infrastructure charges and hookup fees for new homes, thus reducing new home sales.

State and City Supervised Housing for Equity in Electric Rates states that publicly supervised housing is uniquely qualified to obtain open access electricity from wholesale markets, and that the Commission should adopt policies that bring competitive benefits to residents of such housing.

Commission Conclusion

While some residential consumers may be apprehensive about the changes that this rule may have on the electric industry, we are convinced that the changes we are proposing for wholesale markets will benefit them. As wholesale transmission open access becomes a reality, residential consumers should reap the benefits of more competitive bulk power markets and associated lower costs. This rule does not require retail transmission access for retail customers of any size. Moreover, this rule does not require any changes in programs such as assistance to low-income and elderly consumers and weatherization and energy conservation. As discussed in Section IV.I, those programs are under the jurisdiction of the individual states, and will remain under their jurisdiction. Indeed, this rule contains several safeguards to maintain the ability of states to impose conditions on retail access, such as conditions that help to protect residential customers from becoming the residual payer of stranded costs.

[930] *E.g.*, Urban League, Latin League, Black Mayors, Homelessness Alliance, National Women's Caucus, La Raza.

V. Environmental Statement

This section reviews and adopts the final environmental impact statement (FEIS) prepared by the Commission staff in connection with this rule. It identifies the alternatives considered by the agency in reaching its decision; analyzes and considers whether and to what extent the chosen alternative—adoption of this rule—is likely to result in environmental harm; evaluates alternatives and suggestions for mitigating environmental harm from the rule, if any; and states the Commission's decision.

Summary

A. The Environmental Impact Statement

The Commission decided to prepare an environmental impact statement (EIS) evaluating the environmental consequences that could result from adoption of this rule. We did so largely in response to the claims of several commenters, including the Environmental Protection Agency (EPA), who charge that the rule will have significant adverse environmental effects.

Although a number of issues were raised, by far the most prominent concern arises from the theory that competitive market conditions created by the rule will provide an advantage to power suppliers who produce power from coal-fired facilities that are not subject to stringent environmental controls on nitrogen oxides (NO_X) emissions.[931] Under this theory, these facilities, located primarily in the Midwest and South, will, as a result of the rule, generate more power and emit more NO_X, which will contribute to ozone formation. The ozone could add to pollution both in those regions and more significantly in the Northeast, to which area such pollutants could be transported. Those who propound this theory argue that it is the responsibility of the Commission, using its authority under the Federal Power Act, to effect environmental controls that will mitigate what they predict will be significant increases in NO_X emissions associated with this rule.

The staff prepared an FEIS based upon computer modeling simulations of power generation patterns and NO_X emissions likely to occur as a result of the rule. Staff used widely accepted models for studying economic conditions in power markets and simulating emissions of NO_X and other pollutants. These models took into account a variety of different assumptions concerning significant factors such as coal and natural gas prices and other competitive conditions. These factors are critical because increased use of coal-fired generation tends to increase NO_X emissions, while increased use of gas-fired generation is environmentally more benign.

[931] References throughout the Environmental Statement are to emissions from the electric industry, and not to emissions from all sources.

The examination in the FEIS of the environmental effects that are likely to result from implementing the rule is based on an analytic framework that was shaped by comments received in the scoping process and on the DEIS. The study was revised to reflect the frozen efficiency reference case assumptions requested by EPA and other commenters. This was done to ensure full disclosure of possible environmental impacts even though the Commission disagrees that use of these assumptions is appropriate.

It has been observed in the context of agency preparation of an environmental study that ''(t)he NEPA process involves an almost endless series of judgment calls.''[932] That is particularly true where, as here, the agency undertakes to examine the impacts of a proposed regulatory program. In designing an effective assessment of the environmental impacts of the rule, the Commission had to make a number of judgments as to the type and the scope of studies necessary to analyze the proposals sufficiently. Commenters also raised many issues related to the design of the study. For example, the Center for Clean Air Policy contends that the Commission should model a range of mitigation policies; the Missouri Department of Natural Resources contends that the impact of the rule on generation may be locally intense and that these effects should have been studied; and other commenters sought to have the Commission examine different database or modeling assumptions.

For these and similar matters we exercised our judgment as to the appropriate manner in which to treat the issue. For example, we determined not to model a range of mitigation

[932] Coalition on Sensible Transportation, Inc. v. Dole, 826 F.2d 60, 66 (D.C. Cir. 1987). The Court added that ''[i]t is of course always possible to explore a subject more deeply and to discuss it more thoroughly. The line-drawing decisions necessitated by this fact of life are vested in the agencies, not the courts.'' *Id.*

policies because we did not find that the impacts of the rule require the Commission to adopt or implement a plan of mitigation. It would have been extremely difficult, if not impossible, to examine the many varied local impacts that could be expected across the Nation in response to the Rule. We made judgments as to the appropriate database and modeling assumptions to use—in some cases, those assumptions were shaped or changed by comments we received.

In short, many competing considerations came into play during the design of the complex analysis used to examine the environmental effects of the rule. We exercised our judgment, for example, based on consideration of whether matters are within the scope of the rule, the most appropriate way to study the effects of the proposal, and whether the issues raised were relevant to a consideration of the environmental effects of the rule. The Commission's response to issues raised by commenters is reflected in the response to comments set forth in Appendix J of the FEIS. We conclude that the FEIS reflects the appropriate consideration of these and many similar issues.

B. Major Issues

Some comments on the draft environmental impact statement (DEIS), as well as earlier comments in response to Commission scoping inquiries, raise two major areas of objection to the Commission's analysis. First, commenters claim that in determining what NO_X emission levels would be in the future with the adoption of the rule, the Commission did not compare the emissions levels associated with the rule against the appropriate base case. They argue that the Commission should have analyzed and compared the impacts of the rule to a ''no-action'' alternative that assumes that the Commission abandons all its open access policies, not just this rule. Some commenters, including EPA, go even further, suggesting that the Commission compare emission levels projected to result from the rule against a ''frozen efficiency'' case in which other major factors—factors that would increase industry efficiency independent of the Rule—do not occur. Such factors include adoption of pro-competitive state policies and actions by utilities to undertake mutually beneficial voluntary transactions that do not require the use of open access tariffs mandated under this rule. Commenters who advocate either a different ''no-action'' alternative or the frozen efficiency case expect that studies using those assumptions will show that the rule will cause significantly greater NO_X emissions than shown in the DEIS.[933]

Assuming these results, these commenters raise their second major area of concern, which is mitigating the presumed effects of the rule. These arguments vary somewhat but share a common theme: That the Commission has a responsibility, either as a legal or public policy matter, to mitigate what they expect to be the significant environmental impact associated with the rule. They suggest various mitigation schemes, including a FERC-administered NO_X emission allowance program along the lines of the sulfur dioxide (SO_2) program enacted by Congress and administered by the EPA under the Clean Air Act. Other proposals would have the Commission condition the right of a seller to use an open access tariff on certification that the source of the power sold is in compliance with (as yet undetermined) emissions limitations. Another proposal would have the Commission impose a charge on emissions to be paid by utilities to a fund established by the Commission. The added cost to the utilities would work to account for, or ''internalize'', the external costs of emissions.

Commenters advocating Commission-administered mitigation argue that the mechanisms under current law for regulating NO_X emissions are cumbersome and slow, and that the Commission should not (some argue, may not) go forward with the rule unless it puts in place environmental regulatory mechanisms that prevent further increases in NO_X emissions.

Various legal theories are advanced as a basis for Commission environmental regulation under the Federal Power Act. Some argue that the conditioning authority under the Federal Power Act is sufficient to enable us to fashion comprehensive controls on emissions from utility generators because there is a direct causal nexus between power trading (which we regulate) and generation (which we do not). Others argue that such authority lies in the use of our power to impose requirements on utilities ''in the public interest'', enhanced by the National Environmental Policy Act. Others argue that, in remedying undue discrimination, we must correct competitive advantages arising from Congressional decisions to exempt certain kinds of generation facilities from some Clean Air Act regulation.

[933] *See* Section V, Discussion, Subsection C.

C. Commission Conclusions

After reviewing the comments and the additional studies conducted by staff in response to the comments, the Commission adopts the findings in the FEIS.

First, the findings show that, without the rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the rule, NO_X emissions are expected to increase steadily through the year 2010 (the end of the FEIS study period). The extent of the decrease and the increase will largely be determined by the relative prices of natural gas and coal, the two main fuels used to generate electric power in most regions.[934]

In reaching this conclusion, the FEIS used two ''base'' cases. In one (the ''High-Price-Differential Base Case''), natural gas was assumed to become substantially more expensive compared with coal than it is today. In the other (the ''Constant-Price-Differential Base Case''), natural gas was assumed to maintain essentially the same price relative to coal that has existed for the last ten years. The two cases describe the range of emissions due to fuel price uncertainty without the rule and demonstrate the overall trends of decreases until 2000 and increases thereafter.

Second, the FEIS finds that the rule will not in any significant respect affect these overall trends.

The potential impact of the rule was studied initially under two scenarios.[935] In one (the ''Competition-Favors-Gas Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor natural gas as a fuel. In this scenario the effect of the rule is slightly beneficial. Total NO_X emissions are reduced overall by about two percent nationwide from the base cases. In the other (the ''Competition-Favors-Coal Scenario''), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor coal as a fuel. In this scenario the effect is again slight, showing approximately a one percent increase in NO_X emissions nationwide from the base cases. In both scenarios, however, the rule does not have an overall effect on NO_X emission trends.

Stated differently, under any case studied, with or without the rule, there will be an overall net decrease in NO_X

[934] Generally, a relative advantage for coal is likely to increase environmental impacts while a relative advantage for natural gas is likely to create modest environmental benefits.

[935] A third scenario considered improved conditions for the transmission system only. This scenario showed very small effects from the rule and is not addressed further here.

emissions through the year 2000.[936] Thereafter, NO_X emissions begin to increase. The rule does not materially affect either the decline prior to 2000 or the increase thereafter.

Based on these findings the Commission concludes that a comprehensive, Commission-imposed mitigation scheme to address the environmental consequences of the rule is not appropriate. If competition favors gas, the effects are beneficial and mitigation is unnecessary. If competitive conditions favor coal through the year 2010, and NO_X emissions increase slightly as a result of the rule, these minor effects would be effectively mitigated as a part of a comprehensive NO_X cap and trading allowance scheme developed by EPA in cooperation with the Ozone Transport Assessment Group (OTAG) and administered by EPA and state environmental regulators under the clearly established authority of the Clean Air Act.

Further, the Commission believes that staff has selected the appropriate ''no-action'' alternative. An alternative that requires the Commission to reverse all its other open access policies is simply not a ''no-action'' alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the ''frozen efficiency'' case proffered by EPA and the Department of Energy (DOE).[937] Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions.

In one case requested by EPA, staff studied a combination of assumptions most likely to show significant increases in emissions associated with the rule; the case included EPA's frozen efficiency scenario, coupled with the ''Competition-Favors-Coal'' assumptions. Other cases requested by EPA posit dramatic increases in transmission capacity (that we find highly unlikely). Even this combination of assumptions—geared to demonstrate the greatest impact the rule might have on increased NO_X emissions—produced little in the way of environmental consequences associated with the rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005.[938] It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the rule would be higher than the base case by even five percent.[939]

Based on these studies, including the EPA reference case, the Commission endorses the staff findings that the rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true even under scenarios contrived to maximize emissions associated with the rule under circumstances that this Commission believes to be highly unlikely.

Importantly, this is also true in the near- to mid-term. Until the year 2010, even the worst case (the frozen efficiency case) produces results very similar to those produced using assumptions the Commission believes to be reasonable. In short, the rule will not produce an ''ozone cloud'' coming across the Appalachians to threaten the Northeast on the day the rule goes into effect. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial. As a result, calls for Commission mitigation, and in particular for interim mitigation to ''fill the gap'' until programs under the Clean Air Act can be adopted, are unnecessary and disproportionate to the possible effects of the rule.

We also endorse the staff view that it is neither within our statutory authority nor appropriate as a matter of policy to fashion from the FPA a comprehensive clean air regulatory program to address NO_X emissions. As described below, we believe that the mitigation proposals proffered in comments exceed our statutory authority to regulate rates, terms and conditions of sales of electric energy and transmission of electric energy in interstate commerce. We are, in essence and by law, economic regulators. While we have an obligation under NEPA to take the environmental consequences of our actions into account in fashioning our decision—and we have done so—NEPA grants us no new regulatory powers. While NEPA extends our general obligation to engage in reasoned decisionmaking to include the consideration of possible environmental consequences of our actions, it compels no particular substantive result.

Though our conditioning authority under sections 205 and 206 of the FPA is broad, our actions under it are confined to the subject matter of our jurisdiction. That subject matter excludes the physical aspects of generation and transmission. Our actions must derive from and advance our statutory mandate to protect consumers by establishing utility rates and business practices that are just, reasonable, and not unduly discriminatory or preferential. These authorities, however broad they are with respect to economic matters, are not unbounded; they may not be used to ''fill in the gaps'' of regulatory programs that, by law, are not our own.

Moreover, even if it were possible to tease from the FPA some implicit authority to regulate NO_X emissions from utility generators, it is not feasible for this Commission to develop and implement such a program. The mitigation schemes presented in comments are filled with unknowns and complexities that are best resolved by those charged with administration of the Nation's environmental laws. In some cases, the mitigation schemes are based on a model of utility transactions that is fundamentally at odds with the purposes of the rule. For example, several proposals would require the Commission to establish whether emissions from certain units or systems contribute to ozone noncompliance elsewhere, perhaps hundreds of miles away. Other proposals would require the Commission to establish baseline standards for emissions; generating units with emissions above that level would be required to adopt mitigation measures. The technical difficulties associated with these proposals are evident on their face. While resolving these issues is necessary to establish an effective NO_X regulatory program, the Commission does not possess the requisite expertise to establish baseline NO_X emission levels and address the difficult technical and policy issues that are presented in regulating NO_X emissions. EPA is the agency with jurisdiction over and experience with such matters. Although efforts are underway to resolve these issues within the framework of the Clean Air Act, all air regulators agree that much work still needs to be done.

[936] These results are set forth graphically and in tabular form in the FEIS at pp. ES–3 and ES–13. They are also reproduced in Appendix H.

[937] Although DOE agreed with EPA's request that we analyze the frozen efficiency case as a reference case, DOE believes that the DEIS selected the appropriate base case. DOE also argues that the mitigation of any adverse consequences from the rule should be addressed by EPA under the Clean Air Act or by the Congress.

[938] FEIS Table 6–10 at p. 6–17.

[939] *Id.*

Other proposals would require the Commission to track generation that is used for wholesale versus retail sales. However, for example, use of holding company corporate structures, as well as emerging market structures, would make it extremely difficult, if not impossible to distinguish between retail and wholesale transactions. In addition, such measures are inconsistent with the goals of the rule (and the Energy Policy Act) to eliminate time-consuming, inefficient transaction-based approvals that impede open access and to promote entry of sellers into bulk power markets on a competitive basis.

Moreover, any such program implemented by this Commission could well undercut the existing regulatory scheme crafted by Congress under the Clean Air Act, as amended. In particular, we are being asked essentially to rework the legislative decisions made by Congress regarding certain coal-fired generators. Those decisions are at the heart of the 1990 Clean Air Act compromise. The only means Congress has made available for addressing these problems under current law are in the Clean Air Act. If these means prove insufficient to address the NO_X problem overall, the case for change must be presented to the Congress.

Although we have concluded that NO_X emissions problems are most effectively addressed by clean air regulations within the framework of the Clean Air Act, we do recognize that the question of NO_X emissions is a very important one. Our FEIS documents that, with or without this rule, NO_X emissions from all sources are expected to increase over time. This will present a significant environmental issue for the Northeast, which is already struggling to reach current NO_X reduction standards, as well as for other regions of the country that are being called on to participate in an inter-regional solution to the NO_X problem. As the EPA rightly recognizes, attempting to frame an appropriate solution with the tools currently available is a tough job. We therefore understand why those concerned would try to enlist this Commission in an effort to solve this problem with regulatory mechanisms other than those set out in the Clean Air Act. We also understand why even the prospect of exacerbating that problem would ignite the kind of controversy reflected in the comments to this rule, and why, in response, those who have gained Congressional exemptions from certain regulations wish not to have those benefits undermined. At the same time, we understand, and have great sympathy with, the many commenters who have suggested that the economic benefits of this rule to consumers should not be suppressed or delayed by this difficult, ongoing debate.

Our FEIS clearly demonstrates that this rule is not the appropriate vehicle for resolving this very important debate. We believe that our study makes a significant contribution nonetheless. We have added significantly to the understanding of the problem and have established a viable, current baseline for assessing future industry trends. This baseline should serve air regulators well in analyzing overall NO_X emissions in the future.[940] We have resolved some important questions about the role of open access and have established clearly the influence of energy prices on NO_X emissions in the future.

Our study also supports the view held by many commenters that the appropriate regulatory mechanisms for addressing the NO_X problem overall, including emissions from electric utility generating plants, is a NO_X emissions cap and allowance trading scheme along the lines of that developed by the Congress under the Clean Air Act for SO_2 emissions. As staff suggests, even if there are slight environmental impacts associated with the rule, they are better and more effectively addressed as a part of a comprehensive NO_X regulatory program. While Congress did not enact such a scheme for NO_X, it did, as described below, empower the EPA to establish such a program. The EPA is the only federal agency with clear authority and expertise to address this problem. It should do so.

The FEIS also identifies the importance of OTAG to the development of a fair and effective NO_X regulatory program. OTAG, which includes representatives from all affected states, is currently at work developing the analytic basis needed for a regional consensus solution to the NO_X problem. OTAG is also evaluating possible solutions, including an allowance trading scheme. We believe that OTAG's efforts are to be applauded, and we encourage the EPA and all interested parties to work with OTAG to address this issue of national concern.

[940] For example, the data we used to project future industry generation and fuel use update by several years the data relied upon by EPA in its Regulatory Impact Analysis used as a basis for its recently proposed NO_X rule, entitled ''Acid Rain Program; Nitrogen Oxides Emission Reduction Program.'' 61 FR 1442 (1996). We believe the data developed in the FEIS will make a useful contribution to EPA's effort.

Discussion

A. Compliance With NEPA Requirements

1. Background

The Commission issued a NOPR in this proceeding on March 29, 1995. In doing so, we concluded that promulgating the proposed Rule would not represent a major federal action having a significant adverse impact on the human environment and that the proposed Rule fell within the categorical exemption provided in the Commission's regulations for electric rate filings submitted by public utilities under sections 205 and 206 of the FPA.[941] Subsequently, the Commission determined that, despite the availability of the categorical exclusion, it would nonetheless prepare an environmental analysis. On July 12, 1995, the Commission directed staff to prepare an EIS to assess the environmental impacts of the proposed Rule. That notice requested comments on environmental issues and scheduled a scoping meeting for September 8, 1995.[942]

A Notice of Availability of the DEIS was published in the Federal Register on November 27, 1995.[943] The DEIS evaluated several potential alternatives and mitigation measures as summarized below.

A Notice of Availability of the FEIS was published in the Federal Register on April 19, 1996.[944]

2. General Requirements

Section 102 of NEPA, 42 U.S.C. 4332, requires that federal agencies prepare an EIS on proposals for major federal actions significantly affecting the quality of the human environment. The objective is to build into the agency decisionmaking process careful consideration of environmental aspects of proposed actions, including the evaluation of reasonable alternatives. Although we believe a categorical exclusion to be available,[945] the Commission has performed this EIS to ensure that this Rule is promulgated with the benefit of careful consideration of its environmental aspects.

3. Alternatives

The consideration an agency must give in an EIS to alternatives to its proposed action is bounded by a number of factors, including notions of feasibility, whether basic changes would

[941] 18 CFR 380.4(a)(15).

[942] 60 FR 36752 (1995).

[943] 60 FR 58304 (1995).

[944] 61 Fed.Reg. 17,296 (1996).

[945] *See* 40 CFR 1507.3 (1995); 18 CFR 380.4 (1995).

be required to the statutes and policies of other agencies, and the extent to which the proposal would result in significant impacts. The United States Supreme Court (Supreme Court or Court) stated what is required in an EIS with regard to alternatives in *Vermont Yankee Nuclear Power Corp.* v. *NRDC,* 435 U.S. 519, 551 (1978): ''(A)s should be obvious even upon a moment's reflection, the term 'alternatives' is not self-defining. To make an impact statement something more than an exercise in frivolous boilerplate the concept of alternatives must be bounded by some notion of feasibility.'' [946] In this regard, the Supreme Court quoted *Natural Resources Defense Council* v. *Morton,* 458 F.2d 827, 837–38 (D.C.Cir. 1972), with approval as follows:

There is reason for concluding that NEPA was not meant to require detailed discussion of the environmental effects of ''alternatives'' put forward in comments when those effects cannot be readily ascertained and the alternatives are deemed only remote and speculative possibilities, in view of basic changes required in statutes and policies of other agencies—making them available, if at all, only after protracted debate and litigation not meaningfully compatible with the time-frame of the needs to which the underlying proposal is addressed.

The Supreme Court went on to discuss the concept of ''feasibility'', stating that:

Common sense also teaches us that the ''detailed statement of alternatives'' cannot be found wanting simply because the agency failed to include every alternative device and thought conceivable by the mind of man. Time and resources are simply too limited to hold that an impact statement fails because the agency failed to ferret out every possible alternative, regardless of how uncommon or unknown that alternative may have been at the time the project was approved.[947]

Thus, an EIS must discuss the alternatives that are feasible and briefly discuss the reasons others were eliminated. There is no minimum number of alternatives that must be discussed.[948] An agency's consideration of alternatives is adequate if it considers an appropriate range of alternatives—it does not have to consider every available alternative.[949]

The range of alternatives that must be considered in the EIS need not extend beyond those reasonably related to the purposes of the project.[950] An agency is entitled to identify some parameters and criteria related to the proposal for generating alternatives to which it would devote serious consideration. Without such criteria, an agency could generate countless alternatives.[951] Alternatives that are unlikely to be implemented need not be considered, nor must an agency consider alternatives that are infeasible, ineffective, or inconsistent with basic policy objectives.[952] In this sense, central to evaluating practicable alternatives is the determination of a project's purpose.[953]

Furthermore, the range of alternatives that reasonably must be considered decreases as the environmental impact of a project becomes less and less substantial. If a proposal would have minimal environmental effect, the range of alternatives that must be considered is narrow. It would be an anomaly to require that an agency search for more environmentally sound alternatives to a project that it has determined will have no significant environmental effects.[954] Moreover, feasible alternatives may be rejected if they present unique problems or cause extraordinary costs and community disruption.[955]

As applied to the instant case, NEPA does not require the consideration of alternatives that are remote and speculative possibilities because they would require basic changes to statutes and policies. Therefore, alternatives that would require the Commission to ignore open access policies enacted by Congress in the Energy Policy Act and to assume such policies would not be pursued by the states are not feasible and need not be considered. Likewise, the Commission need not consider alternatives that are ineffective or inconsistent with basic policy objectives, or that would cause extraordinary costs and community disruption. Finally, because the rule would have minimal environmental effect, the range of alternatives that must be considered is narrow. We conclude that staff has examined the appropriate alternatives in the FEIS and correctly determined that promulgation of the rule represents the most appropriate action.

Certain commenters have argued that the alternative that calls for the Commission to abandon the policy of promoting transmission access is more appropriate for the no-action alternative than the no-action alternative selected by the staff.[956] We disagree. As discussed below, that contention is more properly an argument about the appropriate baseline to use in the FEIS. That debate has been resolved by the consideration of a reference case that includes a baseline which bounds the effects that those commenters seek to have analyzed.

4. Mitigation

To fulfill the requirements of NEPA with regard to mitigation, an agency must identify and evaluate the adverse environmental effects of the proposed action, in this case the rule. Having identified and evaluated adverse environmental effects, the agency is not constrained from then deciding that other values outweigh the environmental costs of the proposal.

The leading case interpreting this requirement is *Robertson* v. *Methow Valley Citizens Council,* 490 U.S. 332 (1989)(*Methow Valley*). There, the Court explained that:

Although these procedures (preparation and circulation of an EIS) are almost certain to affect the agency's substantive decision, it is now well settled that NEPA itself does not mandate particular results, but simply prescribes the necessary process. *If the adverse environmental effects of the proposed action are adequately identified and evaluated, the agency is not constrained by NEPA from deciding that other values outweigh the environmental costs * * *.* Other statutes may impose substantive environmental obligations on federal agencies, but NEPA merely prohibits uninformed—rather than unwise—agency action.[957]

The Court held that ''(t)o be sure, one important ingredient of an EIS is the discussion of steps that can be taken to mitigate adverse environmental consequences.'' [958] This is so because:

Implicit in NEPA's demand that an agency prepare a detailed statement on ''any adverse environmental effects which cannot be avoided should the proposal be implemented, 42 U.S.C. 4332(C)(ii), is an understanding that the EIS will discuss the extent to which adverse effects can be avoided. More generally, omission of a reasonably complete discussion of possible mitigation measures would undermine the ''action-forcing'' function of NEPA. Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects * * *.[959]

The Court acknowledged that:

There is a fundamental distinction, however, between a requirement that mitigation be

[946] Vermont Yankee, 435 U.S. at 551.

[947] *Id.*

[948] Laguna Greenbelt, Inc. v. DOT, 42 F.3d 517, 524–25 (9th Cir. 1994).

[949] Resources Limited, Inc. v. Robertson, 35 F.3d 1300, 1307 (9th Cir. 1993).

[950] *Id.*

[951] *Id.*

[952] *Id.*

[953] National Wildlife Federation v. Whistler, 27 F.3d 1341, 1345 (8th Cir. 1994).

[954] Missouri Mining, Inc. v. ICC, 33 F.3d 980, 984 (8th Cir. 1994).

[955] Communities, Inc. v. Busey, 956 F.2d 619, 627 (6th Cir.), *cert. denied,* 506 U.S. 953 (1992).

[956] *See* Section V, Discussion, Subsection B.2.

[957] Methow Valley, 490 U.S. at 350–51 (citations and footnote omitted) (emphasis added).

[958] *Id.* at 351 (footnote omitted).

[959] *Id.* at 351–52 (citation omitted).

discussed in sufficient detail to ensure that environmental consequences have been fairly evaluated, on the one hand, and a substantive requirement that a complete mitigation plan be actually formulated and adopted, on the other * * *. Even more significantly, it would be inconsistent with NEPA's reliance on procedural mechanisms—as opposed to substantive, result-based standards—to demand the presence of a fully developed plan that will mitigate environmental harm before an agency can act.[960]

The Court again stressed that ''(b)ecause NEPA imposes no substantive requirement that mitigation measures actually be taken, it should not be read to require agencies to obtain an assurance that third parties will implement particular measures.''[961] Thus, the Court held that mitigation, including mitigation that other governmental bodies have jurisdiction to implement, must be discussed in sufficient detail to ensure that environmental consequences of a proposed action have been fairly evaluated. However, a complete mitigation plan need not be actually formulated or adopted.

The suggestion by various commenters that the Commission is required to adopt and implement a plan to mitigate the impacts of the rule is without legal or factual basis. Even if the effects of the rule were greater than the FEIS shows them to be, *Methow Valley* clearly establishes that, regardless of the impacts of the proposed action, the Commission is required only to understand the impacts of its actions. This compels us to consider and discuss mitigation; it does not require us to adopt and implement mitigation. This FEIS thoroughly examines mitigation of possible adverse environmental effects and concludes that sufficient mechanisms exist to address the impacts of the rule, if any.

5. Role of EPA

Section 309 of the Clean Air Act, 42 U.S.C. 7609, authorizes EPA to review and comment on environmental impact statements prepared by federal agencies. If the EPA Administrator determines that a proposed regulation is unsatisfactory from, among other things, the standpoint of environmental quality, she may refer the matter to the Council on Environmental Quality (CEQ).[962]

In this case, EPA has commented extensively on the DEIS. It sought changes to the staff's analysis, primarily to include the use of the frozen efficiency assumptions. The staff has fully complied with EPA's study requests even though it regards such assumptions as implausible, contrary to the Energy Policy Act and Commission policy, and at odds with industry trends and practical considerations affecting the industry.[963]

Although EPA may disagree with the environmental acceptability of an agency's proposal, the agency is charged with making the ultimate determination whether to implement a proposal; in making that decision, the agency is free to reject advice offered through the comment and referral process.[964] Objections on the part of EPA may give rise to a heightened obligation of the agency to explain clearly and in detail its reasons for proceeding in the face of those objections. This the Commission has done. It has thoroughly examined the impact of the assumptions advanced by EPA; that analysis is detailed in Chapter 6 of the FEIS.[965]

In summary, NEPA prescribes a process and not a result. What is critical is that environmental impacts of a proposed action be adequately identified and evaluated—an important component of this process is understanding the possible mitigation measures that are involved, including measures which may be beyond the jurisdiction of an agency to implement. This requirement does not translate, however, into a requirement that an EIS adopt a mitigation plan, particularly where, as here, the impacts of the rule are small and may be either positive or negative.

B. Analysis of Alternatives

The FEIS evaluated three alternatives to the rule including: (1) A no-action alternative which assumes that the rule is not adopted, but that existing statutory and regulatory policies remain in place; (2) a Commission decision to reverse existing policies and halt implementation of mandatory open access; and (3) a Commission decision to aggressively develop competitive power markets by mandating corporate reorganization or divestiture.

1. The No-Action Alternative

The principal alternative to the proposed action is for the Commission not to adopt the rule, but to continue its existing open access and stranded cost policies. In recent years, the Commission has required public utilities that merge or seek to acquire jurisdictional transmission facilities under section 203 of the FPA to file open access transmission tariffs. The Commission also has required public utilities to file open access transmission tariffs to mitigate market power and to ensure non-discrimination if they or their affiliates wish to sell power at market-based rates. In addition, the Commission processes case-by-case requests made by potential transmission users under section 211 of the Energy Policy Act for transmission service, and has allowed utilities to include stranded cost provisions in their open access transmission tariffs on a case-by-case basis.[966]

Actions taken pursuant to section 211, and pursuant to sections 203 and 205 in merger and market-based rate cases respectively, represent a case-by-case approach to establishing open access. By contrast, the rule would, in a single generic proceeding, require each jurisdictional public utility to file open access tariffs at the same time. The consumer benefits from the rule are expected to be $3.8 to $5.4 billion per year.[967]

Absent action on the rule, the Commission would continue on a case-by-case basis to require public utilities to file open access tariffs and provide case-specific service as necessary or appropriate. Sections 205 and 206 charge the Commission with ensuring that voluntary transmission tariffs are not unduly discriminatory. If the rule were not adopted, the Commission would continue to require that voluntary tariffs be upgraded to offer non-discriminatory open access transmission services pursuant to the Commission's current standards. The result of continuing the Commission's policies without the rule is that the Commission would effectuate a more open transmission grid than is present today, but in a patchwork manner and at a slower pace. Over some extended time period, many, but not necessarily

[960] *Id.* at 352–53 (citation and footnote omitted).

[961] *Id.* at 353 n .16.

[962] The process appropriate for CEQ referral of actions by an independent regulatory agency is not addressed here.

[963] For example, see the discussion on transmission constraints at Section V, Discussion, Subsection C.

[964] *See* Alaska v. Andrus, 580 F.2d 465 (D.C. Cir.), *vacated in part on other grounds sub nom.* Western Oil & Gas Ass'n v. Alaska, 439 U.S. 922 (1978).

[965] The Commission bears the ultimate responsibility for evaluating the environmental impacts of the rule. In doing so, it must consider EPA's comments, but is not bound by them. *See* Citizens Against Burlington, Inc. v. Busey, 938 F.2d 190, 201 (D.C.Cir.), *cert. denied,* 502 U.S. 994 (1991). In that case the Court held that:

Congress wants the EPA to participate when other agencies prepare environmental impact statements. *See* 42 U.S.C. 7609(a). The EPA participated here. But the (Federal Aviation Agency), not the EPA, bore the ultimate statutory responsibility for actually preparing the environmental impact statement, and under the rule of reason, a lead agency does not have to follow the EPA's comments slavishly—it just has to take them seriously. *See Alaska v. Andrus,* 580 F.2d at 474.

[966] *See* Section III.

[967] *See* Section I.

all, utilities would become subject to open access requirements.

The case-by-case approach to achieving open access now in use is slower and more costly, and thereby less desirable, than the generic approach set forth in the rule. Given the rapid changes facing the industry, and the opportunity for great consumer savings, the no-action alternative is not a reasonable alternative to the rule.

2. Abandon the Policy of Promoting Transmission Access

A second alternative is for the Commission to abandon its current policy and take no action whatsoever to foster transmission access. Under this alternative, the Commission would no longer require open access transmission as a condition of mergers and asset acquisitions under section 203 or requests for market-based pricing under section 205, and would no longer grant applications filed pursuant to section 211. Offers of transmission would become strictly voluntary.

This alternative is inconsistent with Congress' general intent in the Energy Policy Act to foster wholesale competition, and also with its specific intent in expanding section 211 to permit the Commission to require a transmission-owning utility to make its transmission system available to eligible users if to do so is in the public interest. This alternative is also inconsistent with the Commission's obligations under sections 205 and 206 to ensure that public utilities do not unduly discriminate in providing jurisdictional services. It is, therefore, not a reasonable alternative to the rule.

3. Corporate Reorganization/Divestiture Alternative

Under this alternative, the Commission would require public utilities either to divest control of their transmission assets or to reorganize their corporate structures to perform their transmission functions through a separate subsidiary, thereby segregating transmission from the rest of the utilities' operations. However, corporate reorganization or divestiture would have no effect on the operation of power plants, which are assumed to be dispatched on the basis of economic efficiencies. Thus, this alternative would lead to the same environmental impacts as the rule. That is, the environmental effects would be no different from those studied in the FEIS.

C. The Scope of the FEIS

The FEIS examines the environmental impacts that could result from implementing this rule. This analysis is undertaken against the background of the existing electric industry. The electric industry currently produces environmental impacts, and those impacts are certain to change over time as the industry responds to factors as varied as changes in demand for electricity, the price of fuels, changes in regulatory programs, technological developments, and changes in market structure.

The FEIS does not examine the environmental impact of electric generation that is required to meet generators' existing service requirements. Nor does it examine the environmental effects of the inter-utility power exchanges that have occurred in the industry for as long as utilities have been interconnected. Rather, the FEIS examines impacts of potential increases in generation and changes in patterns of generation that might result from implementation of the rule.

In creating an analytical construct to examine the impacts of the rule, the staff developed a set of cases that defined the framework for running the computer models utilized to examine the changes in types of power plants constructed in the future and changes in operating patterns of existing power plants, including changes in fuel mix.

First, staff characterized how electric power markets might evolve absent adoption and implementation of the rule by establishing baselines (i.e., base cases) to project the future impacts of the industry.[968] The relative prices of coal and natural gas are critical in establishing what is likely to happen in the future. Accordingly, a range of prices was developed to project the impacts of these factors. In the first baseline, the Constant-Price-Differential Base Case, coal and natural gas prices are assumed to maintain the same relative position they have maintained over the past ten years. In the second baseline, the High-Price-Differential Base Case, natural gas is assumed to become substantially more expensive compared with coal than it has been over the past 10 years. In all other respects, the assumptions underlying the two base cases are the same.

Because the purpose of the base cases is to describe the impacts of the electric industry if the Commission takes no action over and beyond continued implementation of existing policies, the baselines assume that the Commission continues the open access and stranded cost policies it has instituted in recent years.

Some commenters have challenged this aspect of the baselines used in the study. The gist of their argument is that the environmental impacts of these programs have not been evaluated and that the baselines therefore improperly take credit for impacts that have not yet occurred, thus understating the projected impacts of the rule. In general, these commenters argue that the second alternative considered by the staff represents the ''true'' no-action alternative.

At bottom, this debate is not about what constitutes the appropriate no-action alternative. Rather, it is a debate about what aspects of the electric industry should be taken into account when determining future environmental impacts of the industry against which to measure the impacts of the rule. The commenters urge the Commission to consider varying baselines, but in general they oppose inclusion in the base cases of the Commission's ongoing open access and stranded cost programs.

Some commenters not only urge that the Commission not take into account continued implementation of its open access and stranded cost programs, but that it go much farther and establish baselines (against which to examine the impacts of the rule) that do not reflect the impacts of a great many changes that are already taking place in the electric industry. This proposal would establish a baseline that does not take into account: (1) Current Commission transmission policy; (2) programs that states and industry players have adopted to improve industry efficiency; and (3) mutually beneficial transactions that electric companies enter into on a regular basis.

The use of these assumptions would fly in the face of long-standing industry trends which move in precisely the opposite direction. Utilities are reducing reserve margins, improving plant availabilities, and reducing barriers to transmission even without Commission action.[969] Many states are aggressively pursuing plant efficiency policies.[970] These trends are long-standing and are not attributable to the rule, or even to a broader Commission program of open access. These trends, projected into the future, form the basis for the conditions reflected in the FEIS base cases. These trends are fundamentally at odds with the assumptions some commenters wish the Commission to use to establish baselines.

[968] As discussed below, once baselines were established to portray what is likely to happen in the electric industry without the rule, the projected impacts of the rule were then determined against this background.

[969] FEIS Chapter 6.

[970] *Id.*

We conclude that the approach used by staff to develop the baselines used in the FEIS is appropriate. Abandoning current open access policies is unrealistic, contrary to Congressional intent, and at odds with pro-competition policies that are at the heart of the Commission's current regulatory mission. The selection of the appropriate methodology to establish the baselines used in the FEIS is clearly within the Commission's discretion and expertise.[971]

What the commenters challenging this assumption desire is additional study of the impacts of the rule. Specifically, they wish to test the rule against a different set of assumptions for the acknowledged purpose of attributing greater adverse environmental consequences to the rule. The regulations of the Council on Environmental Quality no longer contain a requirement to conduct a conjectural ''worst-case analysis.'' [972] NEPA requires an agency to adequately identify and evaluate the adverse environmental effects of a proposed action.[973] It does not require the agency to ignore the world as it exists.

Nonetheless, to respond to concerns about the baselines used in the DEIS with respect to key atmospheric emissions, the staff conducted sensitivity analyses to examine the outer boundaries of a range of cases requested by some commenters. This range of cases is called the ''frozen efficiency'' case. In essence, the frozen efficiency cases assume that no further open access of any kind occurs during the study period and that efficiency in the industry (for instance, power plant availability) remains frozen through the same period. The assumption that there is substantially more inter-regional transmission capacity than posited in the original analysis is separately examined in the base and rule cases.[974]

We must reiterate that the frozen efficiency case is far more restrictive in its assumptions than a true no-action case in which the Commission simply stops all efforts to promote open access. A true no-action case would closely resemble the FEIS base cases because much of the efficiency gain in that base case would occur even with no move toward open access.

As detailed in Chapter 6 of the FEIS, and as discussed below, even the frozen efficiency case demonstrates results that are essentially the same as those demonstrated by the base cases used by the staff. In the frozen efficiency worst case, when coal prices become considerably more attractive compared to gas prices, national NO_X emissions would be lower than in the base cases used by staff by only one percent (in 2000) to four percent (in 2010). If coal and natural gas prices remain at today's relative levels, the effects would be smaller—zero percent in 2000 to two percent lower in 2010. National CO_2 emissions would be between zero and two percent lower than in the base cases used by the staff over the same time frame.

D. Economic and Environmental Impacts of the Rule

The FEIS reports a quantitative estimate of approximately $3.8 billion to $5.4 billion in benefits per year of cost savings expected from competition under the rule. The FEIS also considers other, non-quantifiable benefits that can be expected from implementing the rule. These benefits include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. Further, the FEIS demonstrates to our satisfaction that the rule is likely to have little or no adverse environmental impact and that any impacts are as likely to be beneficial as harmful.

The issue most frequently raised by commenters involves air quality impacts, particularly the possible transport of NO_X emissions from upwind areas to airsheds in the Northeast and the resulting impacts on ozone non-attainment areas.

With regard to NO_X, the FEIS demonstrates that, as a result of clean air regulatory programs, NO_X emissions nationwide, with or without the rule, will decline through the year 2000, but begin to climb thereafter.[975] This basic trend remains the same in all cases examined in the FEIS. This is because the level of NO_X emissions in any given year depends primarily on one key uncertainty that is not related in any way to the rule—the relative price of natural gas and coal.[976] Lower prices for natural gas, relative to coal, lead to lower levels of NO_X emissions.

The FEIS also demonstrates that increases in access to transmission and efficiencies in electric power markets associated with the rule do not alter the expected trend of NO_X emissions, regardless of the relative price of natural gas and coal. Increased transmission access and industry efficiency facilitated by the rule may either decrease total emissions somewhat or increase them somewhat, depending on whether competitive conditions in the electric industry favor natural gas or coal. When competitive conditions favor natural gas, the effect of the rule is beneficial, reducing emissions somewhat. When competitive conditions favor coal, emissions increase by a small amount. Nevertheless, the overall trend of expected NO_X emissions retains its general shape.

In assessing the projected impacts of the electric industry absent adoption of the rule (*i.e.*, the base cases studied in the FEIS), the most important factor affecting changes in national NO_X emissions is the relative competitive position of coal and natural gas. The most important factor affecting the relative competitive positions of coal and natural gas is price.

National NO_X emissions from the electric industry were 5,844 thousand tons in 1993, the last year for which complete data is available. If relative gas

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971 *See, e.g.*, Sierra Club v. Marita, 46 F.3d 606, 621, 623 (7th Cir. 1995).

972 Methow Valley, 490 U.S. at 354–55. The revised requirement, 40 CFR 1502.22, which pertains to incomplete or unavailable information, is inapplicable as well. The problem here is not incomplete or unavailable information, but rather which existing policies and events should be included in the analysis.

973 42 U.S.C. 4332.

974 Several commenters, including EPA, are concerned that increases in transmission capacities resulting from open access might increase generation levels and thus air emissions. EPA is especially concerned with the expansion of transmission links between the midwest and east coast. The FEIS examines scenarios that increase transmission capacity substantially beyond current levels. This analysis finds that postulated increases do not affect emissions attributable to the rule. We believe increases considered in the FEIS far exceed any transmission capacity increases that might occur as a result of the rule. This is due in part to the fact that state-level siting issues, the principal barrier to major capacity increases in the transmission grid, are unaffected by the rule. The issues regarding enhancement of existing lines are more complex. Competition under open access will lead to improved efficiencies in generation. Transmission, on the other hand, will remain a regulated monopoly function. The rule will reduce barriers to access, but will not open the transmission system to direct competition. Thus, we believe that the competitive effects of the rule on transmission expansion will be relatively small.

EPA urges us to assume that transmission capacity is expanded by 40 percent compared to our base case. We do not believe this is likely to occur. The experience with one proposed new transmission line in the very area EPA focuses on demonstrates this difficulty. Duquesne Light filed an application with the Pennsylvania Public Utilities Commission to construct a new 500 Kv line across Pennsylvania to supply electricity to New Jersey. Within a few days of the filing of the application, over 3,000 individuals and groups filed complaints in opposition to the proposed line. ''Electricity Utility Week'' (November 4, 1991). A bill was proposed in the Pennsylvania Legislature to prevent construction of the line. Another bill was introduced in Congress to halt construction of new transmission lines throughout the U.S. for two years. Duquesne ultimately decided to withdraw its proposal and the line was not constructed. ''The Energy Daily'' (April 4, 1994).

975 FEIS Figure ES–1 and Table ES–2, reproduced at Appendix H.

976 *See, e.g.*, FEIS at ES–8.

and coal prices remain the same, for example, we project that national NO_X emissions will be 5,579 thousand tons in 2005 without adoption of the rule. If gas prices rise relative to coal prices, we project that NO_X emissions in 2005 will be 6,053 thousand tons without adoption of the rule. Stated another way, favorable coal prices are projected to result in NO_X emissions that are about three percent higher in 2000 to 10 percent higher in 2010 over the base case where gas is the favored fuel.

The effect of adopting the rule could be to raise or lower national emissions slightly compared to the effects projected in the base cases. Nationally, in 2005, we project that the Competition-Favors-Coal Scenario (with rising relative gas prices) would add one percent to NO_X emissions above the base case that favors coal. The Competition-Favors-Gas Scenario (with constant relative fuel prices) would lower emissions by two percent compared with the base case that favors gas.

Regional effects are generally similar. In 2005, in the East North Central region (a source of potential increased NO_X emissions that might affect the Northeast), the base cases project small increases in industry emissions (two percent). In that region in 2005, the rule may add as much as one percent to NO_X emissions compared to the relevant base case (the Competition-Favors-Coal Scenario) or reduce emissions compared to the relevant base case by as much as three percent (the Competition-Favors-Gas Scenario).

The EIS uses the UAM–V model to track the effects of projected NO_X emissions on downstream ozone levels during a severe weather period. This detailed air quality modeling shows no real difference in the Northeast between the base case favoring coal (the High-Price-Differential Base Case) and the Competition-Favors-Coal Scenario. Detailed local analysis shows slightly lower ozone concentrations in some locations and slightly higher concentrations in others. None of the differences adds to non-attainment levels projected in the relevant base case, and all fall within the noise levels of the model. That is, they are smaller than the uncertainties in the science underlying the model.

As discussed above, the Commission believes that the base cases used by staff in its analysis are the most realistic and, therefore, the most appropriate cases to consider the potential environmental impacts of the rule. However, as requested by the EPA, DOE, and certain other commenters, sensitivity analyses were conducted to examine the impacts on the results of the analysis if key assumptions are changed as requested by commenters. Presumably, comparing the projected impacts of the rule to the requested ''frozen efficiency'' case provides a measure of the greatest impacts that could possibly (albeit unrealistically) be expected from implementing the rule.[977]

As the FEIS discusses, even comparing projected NO_X emissions under the rule to the highly implausible frozen efficiency case, impacts attributable to the Rule are projected to be modest or non-existent. This holds true even when large (up to 40 percent) increases in transmission capacity are assumed to occur under the rule.[978] Moreover, adding coal-favoring assumptions—which would presumably increase emissions—about future competitive conditions in the electric industry to the implausible frozen efficiency assumptions, NO_X emissions are projected to increase very modestly until the year 2010 (by only two percent in 2000 and three percent in 2005). Even using this highly unlikely alternative to the rule, the analysis projects a net environmental benefit (although a very small one) if gas prices stay constant compared to coal prices.

Concern also has been expressed with regard to the need to mitigate CO_2, mercury, and fine particulate emissions, and with the impact of the rule on visibility. As with NO_X, the FEIS demonstrates that the rule is as likely to improve such emissions and visibility as it is to exacerbate them. In any event, the impact is expected to be small.

In sum, the Commission adopts the FEIS findings that:

- The relative price of coal and natural gas has a larger effect on NO_X emissions than any impacts from the proposed rule. Without the proposed rule, different fuel price assumptions are projected to lead to a 7 percent difference between the two base cases in nationwide NO_X emissions in 2005, with some regions affected more than others.
- The rule is projected to have only slight impacts on NO_X emissions, and the impacts are as likely to be beneficial as harmful. In 2005, if competitive conditions in the electric industry (for instance, heat rates) favor natural gas, the proposed rule is projected to decrease baseline NO_X emissions by 2 percent nationwide. If competitive conditions favor coal, the rule is projected to raise baseline NO_X emissions by 1 percent. Regional effects in both cases are generally similar. In short, any negative impacts that the rule might cause are a small fraction of the uncertainty inherent in fuel price projections.
- Even a substantial increase in transmission capacity (up to 40 percent on every transmission line in the country) would change emission estimates by very small amounts in all cases. In many cases, the changes would represent net environmental benefits.
- Even comparing projected emissions under the proposed rule to the highly implausible frozen efficiency case, impacts attributable to the rule are projected to be modest or non-existent. The staff believes this is an unreasonable comparison because the frozen efficiency assumptions ignore industry trends that the Commission is generally powerless to stop. In effect, they assume that the alternative to the proposed rule is (1) for the Commission to reverse current transmission policy, an action that is inconsistent with Congressional policies under EPAct, (2) for states to cease adopting programs to improve industry efficiency, and (3) for electric companies to cease entering mutually beneficial transactions. Even after adding coal-favoring assumptions about future competitive conditions in the electric industry to the implausible frozen efficiency assumptions, NO_X emissions are projected to increase only very modestly until 2010 (by only 2 percent in 2000 and 3 percent in 2005). Even using this highly unlikely alternative to the proposed rule, the analysis projects a net environmental benefit (although a very small one) if gas prices stay constant compared to coal prices. EPA indicates that it considers the lower gas price assumption to be ''the more likely of the base cases'' (DEIS comments, p. 35).[979]

E. Mitigation Analysis

An agency is required to consider mitigation if the proposed action will result in adverse environmental impacts.[980] The insistence of commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the rule to existing environmental problems. The analysis presented in the FEIS establishes that these assumptions about the impact of the Rule are wrong. As stated in the FEIS,

The sensitivity analyses (*i.e.*, the frozen efficiency case requested by EPA, DOE and other commenters) do not support the argument that the proposed rule is likely to lead to large immediate impacts that require

[977] These assumptions include, and go substantially beyond, the ''no-action'' alternative advocated by EPA and others in positing a baseline that would tend to maximize the amount of NO_X emissions attributed to the rule. This is because under a frozen efficiency scenario *all* increases in power trading (and resulting NO_X emissions) would be attributed to the Rule. In fact, as described below, many of the efficiencies posited under the EPA assumptions are attributable to other factors and certain of the efficiencies (*e.g.*, 40 percent increase in transmission capacity) are wholly unrealistic.

[978] Some commenters assume that large increases in transmission capacity would result in a significant expansion in generation and thus increased emissions. In reality, the analysis present in Chapter 6 of the FEIS indicates that this is not the case.

[979] FEIS at ES–2.

[980] *See* Methow Valley, 490 U.S. at 348–53.

immediate mitigation. In fact, using the more reasonable EIS base cases, it is clear that the proposed rule is at least as likely, if not more likely, to benefit the environment as it is to have adverse environmental impacts. As a result, we believe it is not a responsible course of action to undertake efforts to mitigate speculative adverse environmental consequences that may well not materialize; such action could well have the opposite effect and delay the clear benefits the proposed rule will produce in order to address small, highly uncertain environmental impacts.[981]

Even if the rule were to result in adverse environmental impacts as a result of competitive conditions that favor the future use of coal, such impacts are not likely to occur until about the end of the time period examined in the FEIS. EPA in its comments on the DEIS stressed, based on views it formed prior to knowing the results of the frozen efficiency case, that the Commission should develop interim mitigation until EPA can implement a program of controls. EPA stated in its comments that it has authority to address ''some'' of the impacts it believed would result from the rule, but stated that it would take it considerable time to do so—up to 10 years. The results of the unrealistic worst case analysis demonstrate that adverse effects would not be expected to occur for approximately 10 years in any event. Thus, interim mitigation is not required; EPA will have sufficient time to develop under the Clean Air Act whatever mitigation plan it may deem necessary.

Although the staff concluded that mitigation was unnecessary given the results of its analysis, given the importance of this issue, it nonetheless examined in considerable detail measures, including those proposed by commenters, that could be taken to mitigate adverse environmental consequences of the rule if they were to occur. The FEIS focuses on NO_X emissions in particular given the importance assigned to this issue by commenters.

1. Mitigation Measures Under the Clean Air Act

As discussed in greater detail in the FEIS, the existence for many years of a significant ozone non-attainment problem in parts of the U.S. has led to the development of mechanisms to address this issue. In particular, Congress has established requirements in the Clean Air Act for regulating NO_X emissions. These requirements establish specific NO_X emission levels for certain types of boilers. As discussed below, the Commission is not authorized to alter those requirements as requested by certain commenters.

In the 1990 Amendments to the Clean Air Act, Congress enacted the Acid Rain Program to reduce annual SO_2 and NO_X emissions. For SO_2, Congress established a cap and trade program that uses a market-based allowance system to reduce SO_2 emissions from utilities by approximately 50 percent. The allowance system caps utility emissions at 8.9 million tons a year by 2000. A pool of 8.9 million allowances was then created, each representing the right to emit one ton of SO_2 pollution in a specified calendar year. The allowances can be used to permit current emissions, sold, or held in reserve.

As a result of uncertainty in the understanding of ozone formation and transport, Congress acted less aggressively in regulating NO_X emissions. It chose to limit NO_X emissions from utilities by means of allowable emission limits and to require further study of ozone precursors, leaving room for the EPA to abate NO_X requirements where scientifically justified. Accordingly, in section 407 of the Clean Air Act, 42 U.S.C. 7651f, Congress established a NO_X reduction program which provides that EPA shall by regulation establish annual allowable emissions limitations for NO_X for specified types of utility boilers (Group 1 boilers). Section 407 also provides that, by not later than January 1, 1997, the Administrator shall establish allowable emission limitations for NO_X on a lb/MMBtu, annual average basis for specified other types of utility boilers (Group 2 boilers).

On April 13, 1995, EPA promulgated a Rule setting emission limitations on Group 1 boilers that combust coal as a primary fuel. EPA reports that the April 13, 1995 regulation ''is expected, by the year 2000, to nationally reduce NO_X emissions by an estimated 1.54 million tons per year.''[982]

On January 19, 1996, EPA published a proposed rule to implement the second phase of the Acid Rain Program. This rule proposes to establish NO_X emission limitations for Group 2 boilers and to revise NO_X emission limitations for Group 1 boilers to impose tougher standards. EPA states that ''[t]he proposal would, by the year 2000, achieve an additional reduction of 820,000 tons of NO_X annually.''[983]

In addition, Congress determined to deal with the issue of the interstate transport of ozone by authorizing the formation of transport commissions. The Clean Air Act authorizes EPA to establish transport regions that are charged with assessing the degree of interstate transport of pollutants, assessing mitigation strategies, and recommending revisions to State Implementation Plans to correct the problem. The Clean Air Act specifically establishes an ozone transport region (OTR) for the Northeast. The jurisdictions that comprise the OTR have developed a coordinated approach to this problem that includes adopting a regional cap on NO_X emissions.

Although the OTR process is achieving its purpose, a broader program is clearly appropriate to address the overall problem. As a consequence, the Ozone Transport Assessment Group (OTAG) has been formed which encompasses the OTR and upwind states that contribute to non-attainment. OTAG is performing extensive photochemical grid modeling of the eastern U.S. to determine ozone transport problems and to evaluate the efficiency of various control strategies. OTAG is considering recommending a cap and trade system for NO_X emissions from all sources in a 37-state area comprising the Northeast OTR and upwind states. If the cap and trading system becomes effective it therefore should fully mitigate NO_X emission increases, if any, attributable to open access transmission within the 37-state area. A cap and trade program is also likely to mitigate CO_2 and mercury emissions.[984] Any incremental increases in NO_X, mercury, or CO_2 emissions that may result from the rule can and should be addressed within this existing framework.

All of these factors lead us to agree with the staff's conclusion in the FEIS that a cap and trading system such as that under consideration in the OTAG process is the preferred approach to the overall NO_X emissions problem, including emissions associated with the rule, if any. This approach brings together EPA and the concerned states in a program that utilizes existing regulatory authority under the Clean Air Act.

The OTAG process brings to the table the parties that must participate in making the difficult decisions necessary to fully resolve this problem. OTAG possesses the technical resources and expertise to address the difficult scientific and technical issues that must be resolved to remedy this problem. A cap and trading system will require the

[981] FEIS at 7–5.

[982] 61 FR 1442 (1996).

[983] *Id.*

[984] It should be noted that the science relating to determining mercury emission levels and also to the environmental impacts of CO_2 is uncertain, particularly with regard to the impacts of CO_2 emissions. The FEIS evaluates these matters as best it can under the circumstances.

development of emission baselines for a great many entities; development of such baselines is certain to require extensive modeling and many difficult compromises. OTAG and others have been working towards this end for a long time. A more limited approach—one undertaken by this Commission or aimed at the limited (and only potential) impacts of the rule—cannot render a satisfactory solution. A program designed to deal with the slight impacts associated with the rule will not contribute significantly to the overall solution and could, indeed, impede it if the Commission took actions that prove inconsistent with solutions developed by OTAG or if debate over Commission-sponsored mitigation were to continue to distract interested parties from the preferred route of developing a consensus solution within the framework of the Clean Air Act. We respect the expertise and the goals of the OTAG process and do not believe we can or should substitute for them in addressing this long-term national problem.

2. Mitigation Measures Proposed by Commenters

The FEIS also analyzes NO_X mitigation measures proposed by commenters. These include voluntary measures pursuant to which the Commission would support utility efforts to mitigate pollution and proposals under which the Commission would mandate mitigation. Commenters suggest a variety of Commission actions including using its conditioning authority to require utilities to consider environmental impacts;[985] sanctioning imputed charges in rates to reflect incurred environmental externalities; and designing specific, transaction-oriented mechanisms designed to address the increment of emissions attributable to new wholesale transactions resulting from the rule.[986] The FEIS discusses five proposals in some detail: Those presented by the Center for Clean Air Policy (CCAP), the EPA, Joint Commenters, the Project for Sustainable FERC Energy Policy (Sustainable FERC), and the DOE.[987] Of these, the FEIS recommends the proposal put forward by DOE:

> Staff concurs (with the DOE analysis) that the best solution to the problem of NO_X transport and ozone non-attainment lies in exercise of statutory authority under the Clean Air Act by EPA and the states. Absent Congressional action, no resolution of the difficult political and technical issues will represent a lasting solution of this problem except one that comes from a collaborative process such as OTAG.[988]

As the FEIS explains in great detail, each of the other recommendations suffers from serious shortcomings. In one form or another, they would require the Commission to implement technically complex emissions control regimes outside of the Commission's expertise. Some would require that we duplicate existing monitoring systems. Others would require that we implement provisions that would, in effect, defeat the very purpose of the rule.[989] Indeed, these recommendations would have the Commission embark upon an extensive environmental regulatory regime that appears unwarranted, unworkable and, as discussed below in some detail, beyond our lawful authority. And they would have us act in a way that may well frustrate the ongoing efforts to deal with these problems and would frustrate the benefits to be derived from the rule.

The CCAP asserts that FERC should establish an emissions monitoring program for NO_X and CO_2 and implement an emission neutrality requirement (ENR) to mitigate what it believes to be the impacts of the rule. The monitoring program would require generators to identify emissions associated with off-system sales on a kWh basis in real-time and integrate this information with the data to be made available on electronic bulletin boards (EBBs). Under the ENR aspect of CCAP's proposal, to be eligible for service under open access tariffs, companies that operate plants upwind from the Northeast OTR and the upper Midwest would have to certify that firm and economy off-system power sales using an open access tariff would have no incremental impact on ozone compliance in other areas. All sales for resale that require service under an open access tariff and originate upwind of the OTR would need to include NO_X emissions reduction credits equal to the increase in emissions related to those sales. The seller could meet its requirement to be ''emission neutral'' under the mechanism by achieving the required emission reductions annually at their own facilities, or through purchases of credits anywhere in the airshed.

EPA proposes two mitigation alternatives. In the first, it states that FERC could deny open access service unless there is a showing that the service will not have an adverse environmental impact. Under this approach, EPA, in cooperation with the states in OTAG, would recommend and establish a mitigation mechanism that could be entered into by a customer seeking open access service and used by such customer to make the necessary environmental demonstration supporting the provision of the service. The FERC would rule on whether the mitigation mechanism presented by the customer and the evidence on the likely effectiveness of the mechanism were sufficient to make the environmental demonstration.

In the second proposal, EPA suggests that any fossil fuel-burning generating entity seeking service under open access transmission tariffs would be required to commit by an enforceable contractual undertaking that it will avoid or offset emission increases (measured against as yet undetermined baselines), and periodically certify its compliance with that commitment. Middlemen would have a similar obligation. The generator could meet its emission limits either by making verified emission reductions within its own facilities or by obtaining eligible emissions offsets from other entities. An important element of the mitigation mechanism is the emissions baseline above which mitigation would be required. This mitigation mechanism would operate until superseded by appropriate programs addressing these pollution problems under other authority. EPA's own comments on the DEIS recognize that there may be substantial practical complexities in implementing such mechanism.

The Joint Commenters propose a flexible mitigation strategy pursuant to which FERC would require as part of open access transmission a demonstration that NO_X emissions would not be increased. To qualify for open access transmission access, an electric generating unit would be

[985] For example, EPA suggests that we require certain types of filings, such as a request to charge market-based rates, to include an assessment of environmental impacts and mitigation, if necessary. Joint Commenters suggest we require wheeling and interconnection applicants to demonstrate that their requests will not contribute to increased NO_X or ozone in downwind regions, and Conservation Law suggests linking recovery of stranded costs to the retirement of unsuitable generators.

[986] The FEIS also discusses mitigation measures that can be undertaken by others. These include strategies to require some existing plants to meet more stringent, new NO_X standards, relying on market forces to control inter-regional NO_X transport, or measures that could be employed by the states to limit power purchases based on environmental considerations. *See* FEIS at 7–26 to 7–28.

[987] FEIS at 7–28 to 7–43.

[988] FEIS at 7–43.

[989] The rule represents the Commission's remedy to unduly discriminatory practices found to exist by public utilities that own and/or control interstate transmission facilities. Having found an unlawful practice, we must remedy it. However, EPA would require that those seeking to enjoy the benefits of non-discriminatory open access transmission further agree to go beyond current environmental requirements specified by federal and state authorities authorized by Congress to regulate such matters.

responsible for mitigating any excess NO_X emissions that adversely affect ozone non-attainment areas. Utility systems would be able to comply by use of emission control technology, fuel changes, or other measures to reduce applicable emissions, or by buying appropriate emission reduction credits to offset excess emissions. To comply with this policy, a company would need first to calculate whether it had excess emissions for the ozone season. A company that failed to mitigate would be required to remit to a regional emissions fund all revenues in excess of the incremental operating cost of producing electricity sold under the open transmission access policy during the previous ozone season plus an emissions make-up penalty the following year patterned after the penalty for excess emissions in the Acid Rain Program. The proposed mitigation policy would apply generally throughout the OTAG region.

The outlines of Sustainable FERC's proposal are vague, but it appears to request that FERC, either singly or in combination with other agencies, eliminate the different environmental standards that apply to entities participating in open access transmission. This plan would include the reporting of emissions data to EPA, principles to eliminate the adverse impacts of non-comparable environmental standards, and an EPA-administered emissions monitoring process designed to determine whether generating plant emissions of specific pollutants under open access exceed designated baselines.

Finally, DOE proposes action under the Clean Air Act as the most effective mitigation of the inter-regional NO_X transport problem. DOE supports the activities of OTAG and believes that a regional NO_X cap and trading system is a particularly promising approach. If OTAG does not succeed in addressing the problem, EPA should consider exercising its authority under sections 110 and 126 of the Clean Air Act, 42 U.S.C. 7410 and 7426, respectively, to require states to amend their State Implementation Plans to reach the same result.

The proposals advanced by CCAP, EPA, Sustainable FERC, and Joint Commenters suffer from practical and legal problems that render them unworkable. A common thread is for the Commission to ''level the environmental playing field.'' ''Impacts of non-comparable environmental standards'' are not impacts of this rule, but rather of the Clean Air Act regulations and statutory requirements under which those standards have been imposed. We have no authority to ''level'' the different emissions standards for different types of power plants, when those differences in standards are the direct result of the program adopted in the Clean Air Act and regulations promulgated by EPA. In enacting the Clean Air Act, Congress chose not to impose identical emission standards on all electric utility powerplants, but did create mechanisms for regulation of certain pollutants that can be used to ''level the playing field'' if that is appropriate clean air policy. For the Commission to presume to overturn those standards or seek to impose more stringent standards is something the Commission believes it cannot do.

A fundamental problem that plagues several proposals is the difficulty in identifying causation. While it is generally accepted that there is a link between increased emissions in certain areas of the country and increases in ozone levels in other areas, that link is in many respects poorly understood. In particular, it is difficult to prove that emissions from a particular unit or particular system contribute to ozone noncompliance elsewhere. As a result, it is very difficult to establish an analysis that would support a certification that a particular power sale would have no incremental impact on ozone compliance.

Similarly, the proposals tying ''emission neutrality'' to ''open access transactions'' seem to fundamentally misunderstand the operation of power markets and the role of open access tariffs in moving power from willing sellers to willing buyers. In particular, these proposals do not reflect the difficulty in identifying the transactions that are likely to result from the open access policies adopted in this rule. The rule does not authorize sales for resale of electric energy; rather, it establishes requirements for open access transmission, *i.e.*, it requires utilities with monopoly control of transmission to make transmission service available to customers who want to buy power from someone other than the transmission owner. Open access will facilitate transactions where the transmission owner will not provide service. However, generators do not necessarily have to request service under a Commission ordered open access tariff to make specific sales. There are a number of ways to structure transactions where third party transmission service is either not necessary or is voluntarily available.[990] Even when open access tariffs are used, the sales are not always (or even often) sales from specific generators to specific buyers. Marketers or brokers can buy generation from any number of sources. They can also buy transmission service in blocks that may not be associated with specific sales. Service agreements can be executed that allow use of non-firm transmission service for transactions that are not even known at the time of the execution of the agreement.

The rule envisions a world where transmission will be arranged with minimal transaction cost. Terms, conditions, rates, and even approvals often will be established far in advance of particular transactions. All other problems aside, requiring showings of the kind required by the various mitigation proposals would undermine the basic philosophy behind the rule, would make transactions much more difficult to engage in, would increase transaction costs, and would cause delays resulting in lost efficiencies. In addition, it would directly conflict with the Commission's responsibility under the FPA to remedy undue discrimination in jurisdictional services, which is the fundamental purpose of the rule.

Another significant issue with several of the proposals is how to establish the baselines against which to measure emissions. Establishing such baselines is extremely difficult; EPA itself, for example, has not come to grips with these complexities. The picture is complicated by difficulties in identifying open access transactions that result from the policies implemented by this rule. For example, some utilities use holding company corporate structures in which generation assets are held in an affiliate that sells power at wholesale to the holding company's distribution affiliate. For these utilities, all retail native load service would be subject to environmental review under the mitigation proposals if the base were established by reviewing all wholesale sales. This would make the Commission responsible for addressing all NO_X emissions from power plants for utilities with such corporate structures, a result that goes far beyond the stated goal of mitigating emissions that result from increased interstate trade facilitated by the rule.

As the industry changes, new structures are emerging that will make any system that tries to keep track of wholesale sales even more difficult to administer. California is putting into place an industry structure that could see all generation in the state sold into a central pool and then sold again at wholesale to distributors. Other states

[990] Indeed, over 100 utilities are now providing some form of open access on a voluntary basis.

are contemplating retail market structures that are even more fluid than the California proposal. Differentiating between sales for resale that are for former retail customers and sales for resale that are for ''new'' wholesale customers, and therefore somehow the result of open access policies, would be extremely difficult. In general, it is not easy to distinguish among growth in generation for native retail load, wholesale requirements customers, existing economy sales, and new sales that are facilitated by the rule, either for purposes of establishing a baseline or for tracking responsibility for emissions.[991]

Joint Commenters proposal would have the Commission impose a revenue collection measure—in essence a tax on open access transmission. The Commission is authorized by the FPA to pass through costs, not to collect additional fees from entities utilizing programs established by the Commission. The payment of emission fees is outside the Commission's authority under the FPA.

The FEIS concludes that mitigation by the Commission should not be undertaken in this rule because:

- Any mitigation measures the Commission might undertake are not justified by the small impacts of the rule, which impacts are as likely to be beneficial as they are to be harmful;
- The impacts of the proposed rule are dwarfed by the far larger ozone and NO_X emission issues that either have nothing to do with the electric industry or will be unchanged by the rule or the larger open access program. We believe that it would be ineffective to address the NO_X and ozone issues in a piecemeal way;
- The NO_X issue is part of a long-standing, difficult set of inter-regional environmental issues. Representatives of many interests have invested substantial efforts toward finding acceptable solutions through the OTAG process. Any mitigation the Commission might undertake could usurp EPA's mandate under the Clean Air Act and undermine progress towards comprehensive solutions sought by OTAG. This is not justified by impacts that are small and just as likely to be positive;
- We do not agree that the frozen efficiency reference case should be substituted for the EIS base cases or that competitive forces will favor coal over the next 15 years. But even accepting these assumptions, emissions attributable to the rule are relatively small until well after the turn of the century. So, even accepting such assumptions, the staff believes it would be unreasonable for the Commission to adopt mitigation requirements as part of the final rule; to do so would be tantamount to assuming that EPA and OTAG will not implement reasonable control measures in the next ten to 15 years;
- The Federal Power Act and NEPA, either singly or conjointly, do not authorize the Commission to adopt and implement the proposed mitigation measures. The Commission does not possess (and has no mandate to possess) expertise on the extremely difficult issues involved in atmospheric chemistry and transport. It is fundamentally an economic regulatory agency. As a result, any mitigation measures the Commission undertook would be based on less-than-ideal information and analysis. It is unreasonable for the Commission to attempt such mitigation given the impacts found in this FEIS. This is especially true in light of the substantial additional research that EPA and OTAG are undertaking on the basic nature of the problem;
- Some suggested mitigation measures that might work at the transaction level would undermine the purpose of the rule. There is no justification for endangering the substantial benefits projected from the rule to mitigate a problem that might not exist and that is, in any case, likely to be small.[992]

In sum, the rule is expected to have small impacts and those impacts are as likely to be beneficial as they are to be harmful. Therefore, mitigation is not required. In addition, processes are in place to address the pre-existing NO_X problem—a problem that dwarfs any impacts the Rule might have. These processes are expected to address the underlying transport problems well before any potential harmful effects of the rule will develop.[993]

The mitigation measures that certain commenters urge the Commission to adopt are truly unwarranted in light of these facts. They also fail to recognize or adequately consider the Commission's limited jurisdiction, its lack of expertise required to assess and address the underlying problem, the existing mechanisms and efforts to address the underlying problem, and the balance that has been reached and continues to be defined by the many interests that have invested substantial efforts toward finding acceptable solutions to these problems.

3. Legal and Policy Considerations

The FEIS concludes that the mitigation measures recommended by commenters are beyond our authority to implement and that strong policy considerations militate against their adoption. We agree.

Several commenters contend that the Commission is authorized to use the rulemaking as a vehicle to impose an air emissions regulatory regime on the electric utility industry.[994] Others argue that, as a matter of law and policy, we cannot and should not impose such measures.[995] While the conditioning proposals vary in specifics, all have as their central theme that generators would be forced to agree to operate generation facilities in a manner to reduce air pollution below levels currently authorized by EPA and the states.[996]

The Commission's authority to regulate public utilities is set out in Parts II and III of the FPA. Parts II and III do not provide the Commission with the authority to condition either the provision of, or access to, jurisdictional services on the agreement to undertake environmental mitigation measures.[997] Section 201, which is found in Part II of the FPA, explicitly bars the Commission from exercising the jurisdiction that the proponents of the conditioning

[991] We are also very concerned about the time and effort involved in developing the various programs suggested by commenters. The EPA and OTAG are working on the establishment of emissions standards, which action is an essential prerequisite to three of the proposals. However, developing those standards is among the challenges that EPA believes may take up to 10 years to complete. It simply makes no sense to delay the benefits of the rule (which has slight, if any, environmental impacts) during the period required for experts in the area to develop standards that, once established, can form the basis of a program under existing Clean Air Act authority.

[992] FEIS at 7–48.

[993] Many commenters state that the rule does not require mitigation and urge that a mitigation plan not be adopted. We would also note in light of the substantial number of comments opposing the proposition that we have mitigation authority, that any such mitigation measure we may choose to undertake would, in all likelihood, be subject to judicial review and the inevitable delays and uncertainties that accompany litigation. In the meantime, we would expect actions by OTAG and EPA to eclipse whatever action the Commission attempted to implement during this time.

[994] Alliance for Affordable Energy, *et al.* (Alliance); EPA; Project for Sustainable FERC Energy Policy (Project for Sustainable FERC); and Northeast States For Coordinated Air Use Management (NESCAUM).

[995] *See, e.g.,* AEP at 3; CINERGY at 8–9; Entergy at 11–13; GPU at 2; Midwest Ozone Group at 3; NMA at 5–8; Ohio Consumers' Counsel at 5; Ohio PUC at 1; TVA at 8; and WEPCO at 2. *See also* CCEM Supplemental Comments at 1–5.

[996] *See, e.g.,* CCAP (FERC should establish an emissions monitoring program and implement an emission neutrality requirement); EPA (either deny open access service unless the customer demonstrates no adverse environmental impact or require, through contract terms, any generating entity seeking open access service to avoid or offset emission increases for the benefit of third parties); Joint Commenters (electric generators to qualify for open access must be held responsible for mitigating any excess NO_X emissions through a revenue collection measure); Project for Sustainable FERC (pro forma tariffs to contain environmental mitigation measures imposed on generators). *See generally,* FEIS at 7–28 to 7–42.

[997] Parts II and III of the FPA originated with the Public Utility Act of 1935, 49 Stat. 803, 838 (Aug. 26, 1935) and stemmed in part from the financial abuses in the utility industry in the late 1920s and early 1930s. *See* Report of National Power Policy Committee on Public-Utility Holding Companies, S. Rep. No. 621, Appendix, 74th Cong., 1st Sess. 55–60 (1935); *see also* H.R. Rep. No. 1318, 74th Cong., 1st. Sess. 1–3 (1935). The FPA has been amended several times, most recently by the Energy Policy Act of 1992.

proposals would have us undertake: authority over the *operation* of generating facilities. Section 201(b)(1) provides that:

The Commission shall have jurisdiction over all facilities for (the transmission of electric energy in interstate commerce) or (the) sale of electric energy (at wholesale in interstate commerce), *but shall not have jurisdiction, except as specifically provided in (Parts II and III), over facilities used for the generation of electric energy* * * *. (emphasis added).

This standard is reflected throughout Parts II and III of the FPA. Sections 205 and 206, which are the cornerstones of Parts II and III, concern the regulation of *rates, terms and charges* occurring in connection with transmission or sales subject to the Commission's jurisdiction. Parts II and III do not grant the Commission authority to regulate the environmental aspects of jurisdictional activities.[998] Instead, they provide authority over certain interconnections;[999] the rates, terms and conditions of wholesale sales of electric energy in interstate commerce and transmission in interstate commerce; the disposition and merger of facilities used for such sales and transmission; issuance of securities; accounting matters; and interlocking directorates. Thus, the Commission's jurisdiction over generation extends only to matters directly related to the *economic* aspects of transactions resulting from such facilities.[1000] We do not have jurisdiction over the *physical* aspects of generation facilities.[1001]

This limitation on the Commission's jurisdiction stems from the historical purposes for which the Commission was established. Congress had two objectives in expanding the authority of the Federal Water Power Commission in 1935.[1002] The first was to close the gap created by *Public Utilities Commission* v. *Attleboro Steam & Electric Co.*, 273 U.S. 83 (1927)(*Attleboro*), in which the Court found that under the Commerce Clause states could not regulate wholesale sales of electricity in interstate commerce. The result was a gap in regulation of such sales because there was no federal entity with authority to regulate them at that time. The second was to eliminate the economic abuses that were then rampant in the industry.[1003] In expanding the Commission's jurisdiction Congress made clear that such Federal regulation, however, was ''to extend only to those matters which are not subject to regulation by the States.''[1004]

Several commenters argue nonetheless that the Commission may do indirectly what it is barred from doing directly. Their arguments boil down to the claim that the Commission's responsibility under the FPA to act in the ''public interest'', either alone or in conjunction with NEPA, provides the Commission with the authority to impose environmental regulation on generators to address the supposed impacts of the Rule.[1005] We disagree. In making this argument, the commenters attribute to that standard a breadth of discretion that vastly exceeds the traditional ambit of our authority.

It is well established that NEPA merely establishes a procedural vehicle for assessing the impacts of a proposed action on the environment. It neither expands nor contracts the basic grant of jurisdiction made by Congress to the agency conducting the review, and it does not mandate particular results but simply prescribes a process.[1006] Commenters' arguments that NEPA somehow ''fills in the blanks'' of the FPA to authorize us to impose environmental regulatory regimes on generating facilities, or those who may purchase power from them, is simply incorrect. If we have such authority, it must be found in our substantive statute, the FPA.

Courts have addressed the breadth of our public interest standard on several occasions. The principal case on this point is *National Association for the Advancement of Colored People* v. *FPC* 520 F.2d 432 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976) (*NAACP*). In *NAACP*, a number of organizations requested that the Commission promulgate regulations requiring equal employment opportunity and proscribing racial discrimination in the employment practices of public utilities.[1007] The Commission declined, finding that the FPA did not authorize it to do so. Petitioners appealed, contending that the Commission was authorized and required to act in the public interest:

to order such interconnections of electric power transmission facilities, setting such terms and conditions for the same, as are ''necessary or appropriate in the public interest''; to approve such asset sales and consolidations of interstate electric power companies as are ''consistent with the public interest; to approve such securities issuances by those companies as are ''compatible with the public interest'' and ''consistent with the proper performance * * * of service as a public utility''; to determine ''just and reasonable'' rates for interstate sales and transmission of electric power; and to order that ''proper, adequate or sufficient'' interstate power service be rendered.[1008]

On this basis, they argued that because prohibition of discrimination is in the ''public interest,'' the Commission was therefore required to proscribe discrimination by jurisdictional entities.

The Court rejected petitioners' argument. It observed that:

the (Federal Power) Act's preamble echoes the generality of the foregoing quoted

[998] The statutory framework established by Congress in sections 205 and 206 is not compatible with the administration of environmental regulatory regimes as a precondition to authorization. The Commission has only 60 days to review rate filings under section 205 before they become effective. Absent Commission action rejecting a rate filing or suspending its operation for up to five months within such period, a jurisdictional transaction (either the sale of energy or the transmission of energy) and the proposed rates accompanying the transaction go into effect by operation of law. Some mitigation proposals would require us to reject transactions within 60 days or allow them to go forward but with case-by-case determinations or hearings on environmental effects made within that time period. This could result in transaction gridlock for the trade of electricity in interstate commerce—a situation that is totally at odds with the regulatory framework established by Congress in the FPA and the Commission policy objectives under this rule to minimize regulatory impediments to fluid competitive power sales markets. Moreover, letting transactions go into effect subject to environmental hearings is not likely to produce meaningful environmental controls. Clearly, our processes, which contemplate the resolution of factual matters through hearings and the use of refund obligations to adjust parties' obligations on the basis of the record, make no provision for extensive scientific inquiry and are not designed to accommodate the imposition of clean air standards on power sellers.

[999] *See* FPA section 202(b), 16 U.S.C. 824c(b). *See also* Department of Energy Organization Act, 42 U.S.C. 7151, 7172.

[1000] We also note that section 731 of the Energy Policy Act preserves state and local authority over environmental protection and the siting of facilities.

[1001] For example, we do not have jurisdiction over the physical location of generation or transmission facilities, even though we have exclusive jurisdiction of the rates, terms and conditions of sales for resale or transmission of electric energy in interstate commerce by public utilities using such facilities, *i.e.*, the economic aspects of the use of such facilities.

[1002] The Federal Water Power Commission was established in 1920 with jurisdiction over the licensing of hydropower projects. 41 Stat. 1063 (June 10, 1920). In 1935, it was reconstituted as the Federal Power Commission, with expanded responsibilities over utility regulation. The jurisdiction over the licensing of hydropower was preserved as Part I of the Federal Power Act.

[1003] *See* Report of National Power Policy Committee on Public Utility Holding Companies.

[1004] FPA section 201(a), 16 U.S.C. 824(a). The House, Senate and Conference Reports concerning the Public Utility Act of 1935, *i.e.*, concerning Parts II and III of the FPA, are silent with respect to environmental concerns.

[1005] *See, e.g.*, comments by EPA, Project for Sustainable FERC, and Attorneys General.

[1006] *See, e.g.,* Methow Valley, 490 U.S. at 350–53; *see also*, LaFlamme v. FERC, 852 F.2d 389, 399 (9th Cir. 1988).

[1007] NAACP, 520 F.2d at 433.

[1008] *Id.* at 437–38 (footnotes omitted). The authorities listed cover FPA sections 202, 203, 204, 205, 206, and 207.

phrases, declaring that the sale and transmission of electric power are ''affected with the public interest,'' federal regulation of interstate aspects being ''necessary in the public interest.'' The statute itself nowhere defines the ''public interest,'' but instead leaves the precise ambit of the Commission's concern uncertain.[1009]

The Court found from the entirety of the Act that, ''(o)f the Commission's primary task there is no doubt, however, and that is to guard the consumer from exploitation by non-competitive electric power companies.'' [1010] The Court reiterated that ''(t)he Supreme Court has stated that the words 'public interest' do not constitute a 'mere general reference to the general welfare, without any standard to guide determinations.' '' [1011] Significantly, the Court also found that ''(w)ords like 'public interest' * * * though of wide generality, take their meaning from the substantive provisions and purposes of the Act.'' [1012] The Court concluded that:

Congress has not charged the Commission with advancing *all* public interests, but only the public's interest in having the particular mandates of the Commission carried out, its interest, in other words, in the conservation of natural resources and the enjoyment of cheap and plentiful electricity and natural gas. [1013]

With this, the Court rejected petitioners' argument that the FPA ''public interest'' standard requires the Commission to promulgate regulations prohibiting discriminatory practices by entities who are in some way regulated by the Commission. The Court found that the Commission was *not empowered* to promulgate anti-discrimination regulations because to do so would not be ''reasonably related to the furtherance of the Commission's proper objectives,'' which, under Part II of the FPA, are ''the enjoyment of cheap and plentiful electricity.'' [1014]

On review, the Supreme Court affirmed this limited reading of the Commission's authority to act in the public interest.[1015] In doing so, the Court noted that:

The use of the words ''public interest'' in the Gas and Power Acts is not a directive to the Commission to seek to eradicate discrimination, but, rather, is a charge to promote the orderly production of plentiful supplies of electric energy and natural gas at just and reasonable rates.[1016]

The question the Supreme Court asked in *NAACP* is the appropriate question here concerning the commenters' environmental mitigation proposals:

The question presented is not whether the elimination of discrimination from our society is an important national goal. It clearly is. The question is not whether Congress could authorize the Federal (Energy Regulatory) Commission to combat such discrimination. It clearly could. The question is simply whether and to what extent Congress did grant the Commission such authority.[1017]

We believe the same conclusion is true here for air pollution as the Court found there regarding discrimination.[1018]

The argument by EPA and others that because the FPA authorizes the Commission to act in the ''public interest'' it somehow authorizes the Commission to impose environmental mitigation measures is virtually indistinguishable from petitioners' argument in *NAACP*.[1019] Here, as in *NAACP*, parties urge the Commission to act to achieve worthwhile goals. However, the question is not whether the measures proposed by the parties would advance important national goals. Rather, ''[t]he question is simply whether or to what extent Congress did grant the Commission such authority.'' [1020] Also here, as in *NAACP*, the parties improperly base their belief that the Commission has authority to act under the FPA on an incorrect, overly broad application of the ''public interest'' standard. The goals sought to be advanced by EPA and others are broadly speaking ''in the public interest,'' but they are not goals that Congress has directed this Commission to pursue.[1021] Thus, just as the FPA did not authorize the Commission to take actions that petitioners requested in *NAACP*, the FPA does not authorize the Commission to undertake the types of environmental mitigation measures proposed by the commenters.[1022]

[1009] *Id.* at 438 (footnote omitted).

[1010] *Id.*

[1011] *Id.* at 440, *citing* New York Central Securities Co. v. United States, 287 U.S. 12, 24 (1932).

[1012] *Id., quoting* Alabama Electric Cooperative, Inc. v. SEC, 353 F.2d 905, 907 (1965), *cert. denied*, 383 U.S. 968 (1966).

[1013] *Id.* at 441 (emphasis in original). The Court made clear that ''the conservation of natural resources'' was a Commission interest only with regard to the regulation of hydropower resources under Part I of the FPA. *Id.* at 437.

[1014] *Id.* at 443 and 441.

[1015] NAACP, 425 U.S. 662 (1976).

[1016] *Id.* at 670 (footnote omitted). Several commenters, *e.g.*, Project for Sustainable FERC at 31–32 and Alliance at 53, make much of the Court's statement that there are undoubtedly other subsidiary purposes contained in the FPA and NGA, noting its reference in a footnote that the Commission has authority to consider ''environmental'' questions. NAACP, 425 U.S. at 670 n.6. However, they neglect to mention that the section of the FPA which the Court identified in support of this reference to environmental questions is section 10 of the FPA concerning our Part I authority over hydroelectric licensing matters, not Parts II and III. Part I contains explicit authority for the Commission to consider and require environmental mitigation measures.

[1017] NAACP, 425 U.S. at 665.

[1018] In analyzing the scope of the Commission's authority to act in the public interest, the *NAACP* Court found it useful to analogize to federal labor law. While noting that Congress had ''unmistakably defined the national interest in free collective bargaining,'' *Id.* at 671, the Court found that it could not be supposed that in directing the Commission to be guided by the ''public interest,'' Congress instructed the Commission ''to take original jurisdiction over the processing of charges of unfair labor practices on the part of its regulatees.'' *Id.* Yet this is exactly the form of what EPA and the other commenters supporting our authority to require environmental mitigation would have us do. However, just as with discriminatory employment practices, we can consider the consequences of air pollution practices of our regulatees ''only insofar as such consequences are *directly related* to the Commission's establishment of just and reasonable rates in the public interest.'' *Id.* (emphasis added).

[1019] We note that the standard the Commission is bound to apply in reviewing section 205 and section 206 transactions (which are the focus of the majority of commenters' mitigation proposals) is not a broad ''public interest'' standard, but rather a standard that rates, terms and conditions of such transactions be ''just, reasonable and not unduly discriminatory or preferential.'' 16 U.S.C. 824d, 824e.

[1020] NAACP, 425 U.S. at 665.

[1021] The limited nature of the Commission's ability under *NAACP* to consider ''environmental'' issues is reflected in the few court decisions on this subject. *See Public Utility Commission of California* v. FERC, 900 F.2d 269, 281 (D.C. Cir. 1990) (The broad public interest standards in the Commission's enabling legislation are limited to ''the purposes that Congress had in mind when it enacted this (NGA and FPA) legislation. This rule helps confine an agency's authorization ''to those areas in which the agency fairly may be said to have expertise.''); *Process Gas Consumers Group* v. *FERC*, 930 F.2d 926, 935 & n.14 (D.C. Cir. 1991) (Commission improperly allowed in rates the costs of research intended to benefit ratepayers solely through a ''cleaner environment''; the Court found that the Commission has no particular ''expertise'' in determining and promoting the pollution-reducing effects of natural gas vehicles).

[1022] The Supreme Court's holding in *NAACP* as to the limited ability of administrative agencies to implement broad ''public interest'' mandates, and direction to refrain from straying beyond the specific purposes of the regulatory legislation they are entrusted to administer, is well established. *See Community Television of Southern California* v. *Gottfried*, 459 U.S. 498, 510–11 n.17 (1983) (''[A]n agency's general duty to enforce the public interest does not require it to assume responsibility for enforcing legislation that is not directed at the agency''); *Hampton* v. *Mow Sun Wong*, 426 U.S. 88, 114 (1976) (''It is the business of the Civil Service Commission to adopt and enforce regulations which will best promote the efficiency of the federal civil service. That agency has no responsibility for foreign affairs, for treaty negotiations, for establishing immigration quotas or conditions of entry, or for naturalization policies''); *McLean Trucking Company* v. *United States*, 321 U.S. 67, 79 (1944) (that Congress ''has vested expert administrative bodies such as the Interstate Commerce Commission with broad discretion and has charged them with the duty to execute stated and specific statutory policies'' does not ''necessarily include either the duty or the authority to execute numerous other laws'' beyond enumerated statutory responsibilities); *see also Bob Jones University* v. *United States*, 461 U.S. 574, 611 (1983) (Powell, J., concurring) (''This Court often has expressed concern that the scope of an agency's authorization be limited to those areas in which the agency fairly may be said to have expertise'').

Lower courts have repeated the Court's admonition in this regard on numerous occasions

The Project for Sustainable FERC argues that in *Richmond Power & Light* v. *FERC*, 574 F.2d 610, 616–17 n.22 (D.C. Cir. 1978) (*Richmond Power*), the Court ''suggested'' a broader agency latitude than described in *NAACP*.[1023] We disagree.

Richmond Power involved a case where the Commission was challenged, *inter alia*, because it declined to adopt a particular transmission rate that would have permitted Richmond to shift from oil to some other fuel. The Court affirmed the Commission's decision, finding that:

> Although the Commission must serve the public interest in approving rates, we see no abuse of discretion in limiting this proceeding to the shortrun problem of setting just and reasonable rates for the service theretofore provided in response to the 1973 oil embargo. While an administrative agency must remain faithful to public policies directly related to its regulatory authority, surely at any given moment of history it may rationally decline to affirmatively foster other policies in weighing the specific interests that it is required by the statute to consider. This is especially true when the forum chosen by proponents of the other policy is not well suited to the study of its implications.[1024]

In dicta, in a footnote that began with the Court doubting whether the goal of energy independence is within the Commission's regulatory jurisdiction at all, the Court merely said that ''(n)othing in *NAACP* v. *FPC, supra,* forecloses agency discretion to *consider* in given situations pervasive public policies that it is not required to evaluate in every decision it makes.'' [1025]

The discretion to *consider* public policy matters is a far cry from the authority, or obligation, to regulate those matters. We have considered the environmental impact of the rule. Nothing in *Richmond Power* suggests that the consideration of such matters conveys an affirmative grant of broad new regulatory powers to develop and implement a comprehensive regulatory program in an area expressly assigned by Congress to another agency.[1026]

The cases rejecting commenters' broad reading of our public interest authority are supported by the decision in *Office of Consumers' Counsel* v. *FERC*, 655 F.2d 1132 (D.C. Cir. 1980) (*Great Plains*). There, the Court found that, even under the explicit ''public interest'' standard in section 7(a) of the Natural Gas Act, the Commission is not granted power to act on matters outside of its statutory mandate.[1027]

In *Great Plains*, the Court reviewed a Commission decision to grant a certificate of public convenience and necessity to facilitate construction and operation of a coal gasification plant. Although the NGA does not explicitly provide the Commission with authority to certificate coal gasification projects, the Commission reasoned that it had such authority because the demonstration project was ''in the public interest'' and, because the Commission was authorized under section 7 of the NGA to ''consider'' all factors in reaching a decision on whether to grant the certificate, it had the requisite authority to act.

The Court rejected the Commission's reasoning in that case, stating that:

> Any such authority to consider all factors bearing on the ''public interest'' must take into account what the ''public interest'' means in the context of the Natural Gas Act. FERC's authority to consider all factors bearing on the public interest when issuing certificates means authority to look into those factors which reasonably relate to the purposes for which FERC was given certification authority.[1028]

The Court repeated the finding in *NAACP* that the Commission's authority to act in the public interest is limited to the furtherance of the purposes for which its organic statutes were adopted.[1029]

In concluding that the Commission was not authorized to act as it did, the Court looked to several factors. The Court found it persuasive that Congress had specifically authorized a different governmental entity, the Synthetic Fuels Corporation, to provide support for coal gasification, and that Congress had carefully crafted a special means for providing federal financial assistance for synfuel development.[1030] The Court also found it persuasive that the Commission possessed no expertise in making determinations regarding the relative merits of different synfuel processes, methods or technologies, and that the financing arrangements ''were certainly not ordered with the interests of ratepayers foremost in mind.''[1031] The Court stated that ''by utilizing its statutory tools for a non-statutory purpose, FERC very likely was distracted from its primary statutory duty to protect the interests of ratepayers.'' [1032] Finally, the Court found that the Commission's action seemed to have been prompted at least in part by an attitude that, because Congress had not acted speedily, the Commission could act. The Court criticized the Commission for improperly attempting to preempt Congressional action and to ''fill in''

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in finding that federal agencies improperly have overstepped, or properly have refrained from overstepping, the limitations of their ''public interest'' (or similarly worded) jurisdiction. *See, e.g.*, *The Business Roundtable* v. *Securities and Exchange Commission*, 905 F.2d 406, 413–14 (D.C. 1990) (SEC's assertion of authority under ''public interest'' standard to bar national security exchanges and associations from listing stock of certain corporations invaded traditional state regulatory purview); *Public Utility Commission of California* v. *FERC*, 900 F.2d 269, 281 (D.C. Cir. 1990) (FERC has no authority to consider allegations of copyright infringement or unfair trade practices in determining whether to issue certificates of public convenience and necessity); *American Trucking Association* v. *United States*, 642 F.2d 916 (5th Cir. 1981) (intention of ICC to promote competition is consistent with statutory standard; more generalized intention to promote public welfare needs, unrelated to its legislative instruction to attend to transportation needs of the public, is not); *Natural Resources Defense Council, Inc.* v. *Securities and Exchange Commission*, 606 F.2d 1031 (D.C. Cir. 1979) (SEC has no obligation to promulgate regulations requiring comprehensive disclosure of (among other things) corporate environmental policies unrelated to objectives of federal securities laws); *Sunflower Electric Cooperative, Inc.* v. *Kansas Power & Light Company*, 603 F.2d 791, 799 (D.C. Cir. 1979) (FERC does not have primary jurisdiction to consider antitrust-related issues that do not involve rate-setting practices of public utilities); *O-J Transport Company* v. *United States*, 536 F.2d 126, 131–32 (6th Cir.), *cert. denied*, 429 U.S. 960 (1976) (ICC properly did not stray beyond its congressionally-defined role over transportation regulation by refusing to promote more generalized public welfare concerns); *see also, e.g.*, In re Multidistrict Vehicle Air Pollution, 538 F.2d 231 (9th Cir. 1976) (under antitrust laws, federal district court has no authority to fashion an environmental remedy, intended to reduce auto emissions, that serves no antitrust purpose).

[1023] Project for Sustainable FERC at 31.

[1024] Richmond Power, 574 F.2d at 616–17 (footnotes omitted).

[1025] *Id.* at 616 n.22 (emphasis added).

[1026] Alliance and the Project for Sustainable FERC cite *American Trucking Association, Inc.* v. *United States*, 642 F.2d 916 (5th Cir. 1981), to support an argument that, even under *NAACP*, the Commission can impose conditions under the FPA ''public interest'' standard because there is a ''nexus'' between the primary goals of the FPA and the proffered conditions. As discussed below in greater detail, we disagree.

American Trucking involved review of an ICC rulemaking effort to, among other things, allow government agencies to tender a fair portion of their freight shipments to small businesses and those operated by disadvantaged persons. In reviewing the case, the Court referenced the *NAACP* decision to observe that under the governing law, the ICC's ''useful purpose'' and ''public need'' criterion (used here to justify the regulations) do ''not (refer) to the pursuit of affirmative action goals.'' *Id.* at 921–922. Indeed, it is clear that the Court read *NAACP* as permitting the consideration of ''racial, ethnic and social-economic factors'' only when they relate to the matters within the ICC's authority, *i.e.*, the transportation needs of the public, as opposed to some generalized notion of the general public welfare. *Id.* at 922 n.3.

[1027] NGA section 7(a), like, for example, FPA section 203(a), provides for a ''public interest'' standard of review. Section 7 of the NGA represents the maximum authority the Commission has over environmental issues under that Act. Section 7 provides the Commission authority to approve the siting and construction of facilities.

[1028] Great Plains, 655 F.2d at 1147.

[1029] *Id.*

[1030] *Id.* at 1150.

[1031] *Id.* at 1151.

[1032] *Id.*

where the agency believed federal action was needed.[1033]

The facts and reasoning in *Great Plains* are directly analogous to this proceeding. Congress has specifically authorized other entities—EPA and the states—under other statutes to address air pollution. The Commission is being urged to regulate in an area in which, as in *Great Plains,* it possesses no special expertise (*i.e.,* in making determinations regarding appropriate air pollution control mitigation measures) and in which it is not authorized to act.[1034] Finally, as in *Great Plains,* if the Commission were to undertake mitigation, it would be diverted from its primary statutory duty to protect the economic interests of ratepayers, *i.e.,* by having to continually monitor compliance with mitigation conditions.[1035]

As in *Great Plains,* the Commission is being urged to act at least in part because of the belief that Congress has not provided a sufficiently speedy process by which to regulate air pollution produced by electric utilities. The EPA argues that:

> Regulations under the Clean Air Act must in general be implemented through State Implementation Plans; the time from reaching a general conclusion that control is needed to adoption of necessary regulations by states generally takes from three to five years; that regulatory lag time means compliance with new rules can be, and usually is, more than a decade from the point at which the problem occurred. Ten years of bad air is ten years delay too many.[1036]

That Congress has imposed upon the EPA procedures that the EPA and others find burdensome and overly time consuming is an issue for Congress and EPA to address, not the Commission.[1037]

This conclusion has particular force when, as here, we are urged to impose environmental restrictions on certain coal-fired generators in spite of Congressional actions regulating those entities. In essence, some commenters argue that under a very tenuous connection to the public interest standard of the FPA we may undertake to do more than the agency that Congress has authorized to act on such matters. This result is not a correct reading of the law and we reject it.

Several commenters attempt to overcome the various Courts' views of the scope of the public interest standard under the FPA by arguing that there is a ''direct nexus'' between the Rule and environmental concerns that suffices to invoke an imputed authorization under the FPA to prescribe environmental requirements on generators.[1038] To this end, they argue that the purpose of the rule is really to facilitate the least-cost use and construction of generation resources and that the environmental consequences of these actions will impact economic efficiency, rates, competition, and competitive markets. Thus, they conclude that we have the authority to require that those who seek to obtain transmission access on a non-discriminatory basis must first mitigate air emissions under as yet undefined standards.

These commenters misstate the question. The question is not whether there is a nexus between the rule and environmental concerns. Clearly, electric utilities contribute to pollution; anything that facilitates the sale of power from whatever source is, under this tenuous logic, ''related'' to environmental concerns.[1039]

However, as discussed below, Congress did not give us plenary powers over public utilities to shape their activities in response to a broad range of public policy concerns. The nexus that must be established is a nexus between the requirements sought to be imposed, in this case emission controls, and the statutory *standards* which authorize us to act. That is, in order to impose the environmental conditions sought by commenters, a direct connection must be established between those conditions and our duty to determine that the rates, terms and conditions of service under our open access tariffs are not unjust, unreasonable, unduly discriminatory, or preferential.

It is on this point that commenters' arguments founder. While the Commission has broad latitude to interpret these standards to advance the interests of ratepayers, we cannot implement policy objectives that are not assigned to us and that are, in fact, clearly assigned to other entities. The Congress has assigned responsibility for environmental regulation of air quality to EPA and the states; it has explicitly charged them with dealing with such pollution from electric generating facilities. While, as noted earlier, we do not dispute the need to give appropriate weight to environmental considerations in making decisions within our authority, we cannot use that authority to accomplish public policy objectives that, by statute, are required to be implemented and administered by other agencies.[1040]

[1033] *Id.* at 1151–52.

[1034] To our knowledge the only time Congress has asked the Commission with respect to its regulation under Parts II and III of the FPA to address environmental issues was in Section 808 of the Clean Air Act Amendments of 1990. There, Congress directed the Commission, in consultation with EPA, to study the environmental externalities of electricity production. The Commission staff did so and provided the required report to Congress. While the Commission in compliance with the 1990 Amendments also addressed the accounting issues related to SO_2 emissions trading, the Commission did so within the context of its accounting authority under the FPA.

[1035] EPA argues that the Commission would not be required to monitor compliance with the environmental mitigation measures. However, if environmental mitigation is within our statutory mandate, we could not delegate that authority to others. *See* EPA at 51.

[1036] EPA at 4–5; *see also* Project for Sustainable FERC (protections achieved by the Clean Air Act Amendments of 1990 are in danger of being destroyed by the Energy Policy Act's open access policies if those policies are implemented without environmental mitigation).

We would also note that the premise upon which EPA makes this argument—that air emissions will rapidly increase with implementation of the rule—is not supported by the record. *See* Section V, Discussion, Subsection C.

[1037] We believe that this conclusion is supported by section 205(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA, *inter alia,* amended the FPA in certain respects but also gave the Commission authority in certain sections, such as PURPA sections 205(a) and 210, that did not amend the FPA. Under PURPA section 205(a), the Commission in certain circumstances may exempt electric utilities, in whole or in part, from state laws, rules or regulations which prohibit or prevent voluntary coordination, including agreements for central dispatch. (Of course, the central dispatch is dispatch of generation facilities.) However, PURPA section 205(a)(2) provides that no exemption may be granted if the state law, rule or regulation is designed, among others, to protect public health, safety or welfare *or the environment.* In commenting on the limitation of the Commission's exemption authority under PURPA section 205(a), the Conferees noted that the prohibition includes ''regulations under the Clean Air Act.'' H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. 95 (1978), *reprinted in* 1978 U.S. Code Cong. & Ad. News 7797, 7829. While the Commission's statutory authority has been modified in legislation enacted subsequent to PURPA, the provisions of PURPA section 205(a) have not been modified.

[1038] *See, e.g.,* EPA at 54. *See also* Alliance; Project for Sustainable FERC; Coalition; Signatories; CCAP; Attorneys General.

[1039] Under this logic, the Securities and Exchange Commission, for example, which facilitates utility financing for new facilities would be empowered to administer environmental requirements.

[1040] We are also troubled by the confusion that persists as to the usefulness of imposing a condition on the use of open access tariffs as a means to accomplish environmental goals. As noted earlier, the Commission's decision to compel the filing of open access tariffs is intended to provide access to third party power suppliers who need access across a utility's transmission system. Open access will primarily benefit independent power suppliers offering power from new facilities, most of which under current market conditions are likely to be gas-fired facilities. Traditional utilities that own the generating plants of particular concern to commenters (*i.e.,* coal-fired plants subject to less strict environmental controls) have extensive transmission systems that they can use to get power to market. Thus, the exercise of conditioning authority is more likely to impede sales from new, cleaner facilities than it is sales from older, coal-fired facilities. It makes no sense from an economic or environmental perspective to burden new transactions with this cumbersome condition for what will likely be little in the way of effective environmental controls.

Some commenters have sought to address this issue by characterizing the proposed conditions as necessary to create a level competitive playing field among generators. For example, Alliance argues that unless the Commission requires environmental mitigation certain competitors in the bulk power market (those with ''dirty generation'') would be favored over ''clean'' competitors. It argues that:

Mitigation of the environmental impacts resulting from the NOPR has a direct relationship to ensuring that open access is implemented under terms of economic fairness for all utilities and utility consumers, and not merely those with current low-cost regulatory advantages.[1041]

We note that all power generation technologies have different costs. For example, hydroelectric facilities which, like coal-fired facilities, may have environmental mitigation conditions imposed on them, may be quite expensive to build compared to gas or oil-fired generation, but their operating costs may be significantly lower. These cost differences may reflect the different costs of complying with mandated environmental requirements; the prudent costs of complying with such mandates may be reflected in rates.

Indeed, sellers come to the power markets with a variety of advantages and disadvantages, many of which are the result of federal laws—for example, tax preferences, labor standards, and similar matters. In empowering the Commission to remedy undue discrimination and promote competition, Congress has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure ''economic fairness.'' Such homogenization of competitors, or their costs, has never been a goal of the FPA.[1042]

In short, the ''economic nexus'' urged by commenters advocating that the Commission undertake to regulate air emissions is inconsistent with the ''charge to promote the orderly production of plentiful supplies of electric energy'' envisioned by the FPA.[1043]

We have exercised conditioning authority in the past only where necessary to ensure that jurisdictional transactions and rates do not result in anti-competitive effects, or are not unjust, unreasonable or unduly discriminatory or preferential.[1044] Thus, the conditions we have imposed have involved economic regulatory matters within our purview under the FPA.[1045] Any exercise of conditioning authority must, as the Supreme Court noted in *NAACP*, be directly related to our economic regulation responsibilities; EPA and the other commenters have not demonstrated such a nexus.[1046]

This distinction is more evident when one considers the way in which we are authorized to treat the costs of environmental compliance. There are legitimate costs of environmental compliance that should be reflected in jurisdictional rates to the extent prudently incurred, just as the prudent costs of complying with, for example, occupational health and safety requirements designed to protect utility employees should be reflected in jurisdictional rates. This we are authorized to do and we routinely review and allow such costs.[1047] However, the fact that the costs of providing utility workers with a safe workplace are properly reflected in utilities' jurisdictional rates does not mean that we have authority to condition sellers' rates or customers' use of jurisdictional services on meeting safety regulations that are in the public interest. The same rationale applies to environmental matters related to the rule.[1048]

Commenters also raise several other arguments to support the claim that the Rule requires us to undertake environmental regulation to remedy supposed impacts of the rule. EPA, for example, argues that requiring environmental mitigation would not run afoul of the prescription of section 201(b)(1) of the FPA enjoining our regulation of generation facilities because the ''regulation of transmission tariffs necessarily has manifold indirect effects on generation sources. The proposed mitigation mechanism would influence generation sources in a similar, indirect manner.'' [1049]

EPA fundamentally misunderstands the purpose of the Rule. We act to remedy unduly discriminatory practices in, as here for example, the provision of transmission access. Since ''undue discrimination,'' is one of the matters ''specifically provided in this Part (II)'', *i.e.*, in FPA sections 205 and 206, we are acting within the bounds of our statutory mandate and the effect that the Rule may have ''over facilities used for the generation of electric energy'' is specifically sanctioned. Indeed, many generators are transmission customers who we are obliged to protect under the FPA. That there may be indirect environmental consequences from our Rule does not trigger our jurisdiction under the FPA.

[1041] Alliance at 55. *See also* Project for Sustainable FERC at 37.

[1042] For the same reason, we do not have authority to impose an obligation on utilities to ''internalize'' environmental externalities. *See generally* FEIS at 7–24. In effect, such proposals would involve the Commission requiring a surcharge on power sales rates fixed at some amount equal to the environmental ''cost'' inflicted by the generation supporting those sales. Assuming such a surcharge could be calculated, imposing such a cost would be to fix a rate without reference to any cost incurred by the public utility. Indeed, we would impose in rates, and require ratepayers to pay, a cost that was manifestly not incurred by the utility. In reality, such a surcharge would require us to impose a tax or a penalty, neither of which we are authorized to impose.

The SO_2 program created under the 1990 Clean Air Act Amendments illustrates the way in which EPA and FERC authority can intersect to accomplish the goal of internalizing externalities. There, the Congress by capping emissions and providing for a market in emission allowances required utilities to ''pay for'' the right to emit SO_2. These costs are legitimate costs and the *Commission's* role is to permit their recovery in rates. Similarly, a comparable NO_X cap and trading scheme established by EPA would ''internalize'' the external costs of NO_X pollution and the Commission would provide for prudently incurred allowance costs in rates.

[1043] NAACP, 425 U.S. at 670.

[1044] Cf. Utah Power & Light Co., Opinion No. 318, 45 FERC ¶ 61,095 at 61,280–83 (1988) (discussing the Commission's authority to condition a merger). Unlike the situation in Opinion No. 318 where the Commission had the authority under section 203 to disapprove a merger upon a finding of actual and potential anticompetitive effects, the Commission's rate authority under sections 205 and 206 does not permit the Commission to deny the proposed rates out of a concern that such action will result in an increase in air pollution. *See* Monongahela Power Co., 39 FERC ¶ 61,350 at 62,096, *reh'g denied,* 40 FERC ¶ 61,256 (1987). As a result, we have no authority to condition the same result under these sections on environmental mitigation.

[1045] The obligation of the Commission to weigh antitrust considerations highlights this point. The Commission must take into account anticompetitive effects when setting rates. *See Northern Natural Gas Co.* v. *FPC,* 399 F.2d 953 (D.C. Cir. 1968). However, we are limited as to the remedies we may impose. We cannot go further and assess the range of remedies that, for example, a Court may exact upon finding an antitrust violation. *See generally* NAACP, 520 F.2d at 441.

[1046] Project for Sustainable FERC, at 32–33, and Alliance, at 41–42, have attempted to argue that *NAACP* actually supports the Commission having authority to order environmental mitigation. Their argument fails because they have not shown, and cannot show, the necessary direct nexus to our economic regulation.

[1047] For example, our regulations permit 100 percent of any construction work in progress for pollution control facilities allocable to wholesale sales to be included in rate base. *See* 18 CFR 35.25 (1995). This regulatory action, directly related to our core ratemaking responsibilities, removes an economic disincentive for public utilities to invest in structures designed to reduce the amount of pollution produced by a generating facility. *See* 18 CFR 35.25(b) (definition of pollution control facility).

The Commission also addressed the ratemaking consequences of SO_2 emissions trading in response to a petition from the Edison Electric Institute. This is another example of the Commission's proper exercise of its jurisdiction, *i.e.*, over the costs of environmental compliance.

[1048] Indeed, our regulations provide for such cost recovery.

[1049] EPA at 50.

EPA next argues that, even if we could not impose a specific mitigation mechanism for open access transmission, we could deny transmission service unless there is a showing that the service will not have an adverse environmental impact.[1050]

We have already discussed why we believe this approach is unworkable and inconsistent with sections 205 and 206 of the FPA.[1051] Plainly stated, EPA would have transmission customers assume an additional regulatory burden in order to be treated lawfully.[1052] Quite apart from this fundamental problem, such a regime is beyond our authority. Our regulation under sections 205 and 206 is over the *selling* public utility's rates, terms and conditions, not over the buyer's agreement to undertake measures which have no nexus whatsoever with the seller's costs or terms of service.

EPA states that its alternative mitigation mechanism would not be a condition of the open access *tariff*, but apparently a condition on the ability of customers to take service under the tariff. However, our authority to set terms and conditions of eligibility derives from precisely the same authority that we use to set other tariff terms. It must still be based on a nexus with the subject matter of our jurisdiction. For buyers, open access is a right, not a privilege. We fail to see, given the direction of the FPA to ensure these rights, any basis for us to undertake the actions EPA proposes.

Finally, EPA points to the Commission's decision to exclude certain diesel facilities in defining qualifying facilities (QF) under PURPA section 210.[1053] However, this provides no precedent for imposing environmental standards to prevent customers from obtaining nondiscriminatory open access. Whatever the merits of that decision,[1054] the Commission subsequently found that any facility that satisfies the ownership and technical requirements for QF status set forth in PURPA and the Commission's regulations is a QF without any action by the Commission.[1055] More to the point, EPA ignores the fact that, in issuing environmental findings with its QF Rules, the Commission found that environmental concerns were a local matter to be handled under other statutory authorities. While PURPA permitted certain qualifying facilities to be exempt from state and federal laws,

> it excludes exemptions from environmental laws. Thus, a qualifying facility may not be built or operated unless it complies with all applicable local, State, and Federal zoning, air, water, and other environmental quality laws, and unless it obtains all required permits.[1056]

Thus, while we have noted that QFs are required to satisfy all environmental requirements, we have not viewed our responsibilities under PURPA as permitting us to enforce compliance with environmental laws.[1057]

EPA then proposes to require any fossil fuel-burning generating entity seeking service under an open access tariff to (a) commit by contract to avoid or offset emissions increases (measured against certain baselines), and (b) periodically certify its compliance with that commitment.[1058] This proposal is neither workable nor within our jurisdiction.

The deficiency with respect to (a) is that we have no authority to require such action. While EPA cites to FPA section 206 for the proposition that we may change jurisdictional contracts, we may do so only if the contract is, for example, unjust or unreasonable with respect to matters within our jurisdiction, *i.e.*, economic regulation. Our standards for acting are strictly prescribed under the FPA.[1059] As *NAACP* and *Great Plains* teach, sections 205 and 206 do not provide the Commission with the means to remedy every possible problem that is in any fashion related to a sale for resale or transmission in interstate commerce by a public utility. Since we do not have the authority to require (a), it follows we cannot require the periodic certification of compliance recommended in (b).

EPA notes that it ''could establish a procedure whereby a generator could *voluntarily* subject its facilities to emission limits that are enforceable by EPA and/or state environmental authorities.'' [1060] This is a matter within EPA's province, and we support EPA in undertaking whatever measures it determines to be within its authority and appropriate to the problem.

Alliance argues, at 47–51, that sections 211 and 212 of the FPA, as amended by the Energy Policy Act, authorize the Commission to impose environmental conditions. To the extent that Alliance's arguments rely on the ''public interest'' language used in section 211, we believe that the discussion above already addresses such arguments, with one exception: Alliance argues that the House Report for the Energy Policy Act states that the purpose of the Act is to ''increase U.S. energy security in cost-effective and environmentally beneficial ways

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[1050] EPA at 51. *See also* NESCAUM at 19; Alliance at 18, 53; Project for Sustainable FERC at 37.

[1051] CCEM argues that the tracking of documentation with environmental compliance requirements will stifle the very competitive bulk power market that EPA and others profess to support. CCEM notes that ''(i)t is both ironic and inexplicable why EPA, the agency charged with enforcing the nation's clean air and other environmental protection laws is so anxious to shift this responsibility away from itself and onto economic participants in the incipient, competitive power supply industry.'' CCEM Supplemental Comments at 4.

[1052] We also note that under EPA's scheme those most likely to benefit from denying access—transmission sellers—would be provided the authority to lawfully deny transmission access.

[1053] EPA states at 51–52 that:

> In implementing section 210 of the Public Utility Regulatory Policies Act, the FERC took the approach of declining to act because of the potential adverse environmental impacts of the action. Section 210 required the FERC to prescribe regulations ''to encourage cogeneration and small power production * * * Because of its concern that ''diesel and dual-fuel commercial cogeneration facilities in the New York City area had the potential to cause environmentally significant effects'' (46 FR 33025) (1981)), the FERC issued regulations that excluded new diesel cogeneration facilities from being ''qualifying facilities.'' 45 FR 17964.
>
> EPA maintains that the FERC similarly has authority in the instant case to deny open access transmission to the extent such transmission would have adverse environmental impacts.

[1054] The Commission subsequently modified this position and decided to treat diesel cogeneration facilities like other QFs.

[1055] *See* CMS Midland, Inc., 50 FERC ¶ 61,098 at 61,277–278 (1990), *reh'g denied,* 56 FERC ¶ 61,177 (1991), *aff'd mem. sub nom.,* Michigan Municipal Cooperative Group, v. FERC, 990 F.2d 1377 (D.C. Cir.) (*per curiam*), *cert. denied,* 114 S.Ct. 546 (1993); *see also* Mesquite Lake Associates, Ltd., 63 FERC ¶ 61,351 (1993); Citizens for Clean Air and Reclaiming Our Environment v. Newbay Corporation, 56 FERC ¶ 61,428 at 62,532–33, *reh'g denied,* 57 FERC ¶ 61,219 (1991).

[1056] Small Power Production and Cogeneration Facilities—Environmental Findings, 10 FERC ¶ 61,314 at 61,632 (1980). The Commission has included similar language in every order it issues finding qualifying facility status. *See also* Small Power Production and Cogeneration, Order No. 70–E, FERC Stats. & Regs., Regs. Preambles 1977–81 ¶ 30,274 at 31,596 (1981).

[1057] The important point is that the Commission has fully complied with its responsibilities under NEPA in both instances. Whatever initial decision it may have come to in 1981 with regard to the particular circumstances involved in adopting QF regulations under PURPA is irrelevant to the instant rulemaking.

[1058] EPA's proposal apparently would apply only for NO_X, CO_2 and mercury. *See* EPA at 58 n.31 and 60 (because there is already a nationwide cap on SO_2 emissions in the Clean Air Act, there is no need for mitigation for that pollutant). In other words, EPA apparently would require us to impose environmental mitigation only in those instances in which Congress has not provided a nationwide cap for a pollutant.

[1059] *See United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.,* 350 U.S. 332 (1956); *FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348 (1956).

[1060] EPA at 59 (emphasis added). *See also* Project for Sustainable FERC at 38–39 (proposing that a regulatory plan be developed through consultations between the Commission, EPA, DOE, and appropriate regional and state regulators and then presented in the FEIS).

* * *.'' [1061] However, even if we assume that the Report language reflects Congressional intent for the Energy Policy Act in general, we note that, in Title VII of the Energy Policy Act concerning electricity, the only mention of the environment was, as noted above, in section 731 which specifically provided that nothing in the Energy Policy Act in any way interferes with the authority of any state or local government relating to, *inter alia,* environmental protection. While we do not quarrel with the proposition that Congress in the Energy Policy Act obviously had concerns with environmental matters,[1062] Congress did not provide the Commission with any authority to mandate environmental mitigation.

We have undertaken an extensive NEPA analysis to consider the environmental effects of our Rule. We cannot, however, take NEPA's requirement to consider environmental effects as authority to require the environmental mitigation proposed in the comments. Congress has charged other agencies, most notably the EPA, with the responsibility of protecting the environment and enforcing environmental laws.[1063] While we stand ready to work in a complementary fashion with these agencies, we believe that any attempt by the Commission to go beyond the economic regulation that Congress has delegated to us would be *ultra vires.*

To summarize: The Commission's jurisdiction under Parts II and III of the FPA is limited to matters relating to economic regulation. Neither the relevant statutes nor the case law supports the expansive and novel reading of the Commission's authority advocated by the commenters that argue that we have environmental mitigation authority. The Commission is not explicitly given such authority in either the FPA or NEPA. Moreover, the FPA and the case law clearly compel the conclusion that we cannot impose environmental conditions that do not directly relate to the economic matters over which we have jurisdiction. To do so, in fact, would prevent the Commission from effectively carrying out its responsibilities under the FPA.

F. Coastal Zone Management Act Issue

By letter dated February 22, 1996, and filed with the Commission on March 5, 1996, the Connecticut Department of Environmental Protection (Connecticut) notified the Commission that it has determined that the Commission's proposed action in this rulemaking proceeding is likely to adversely affect Connecticut's coastal resources. Connecticut reasons that the Rule's promotion of competition ''is likely to increase energy production by mid-west coal burning plants(,) which will in turn increase the export of nitrogen and sulphur oxides.'' Connecticut states that airborne nitrogen emissions are linked to adverse environmental impacts in Long Island Sound. It therefore asserts that, pursuant to section 307(c)(1) of the Coastal Zone Management Act (16 U.S.C. 1456(c)(1)) (CZMA), and the federal regulations promulgated thereunder (15 CFR part 930), the Commission is required to provide it with a determination of the Rules' consistency with Connecticut's federally approved coastal management plan.

Section 307(c)(1)(A) of the CZMA deals with the prevention or amelioration of adverse physical impacts on coastal zone resources attributable to federal activities. The legislative history indicates that in enacting the CZMA Congress was concerned with the adverse effects on coastal lands and waters of such activities as excavation, filling, diversion of water or sediment, clearing, and off-shore energy exploration and dumping.[1064]

As discussed more fully above, section 201 of the FPA declares that the Commission shall *not* have jurisdiction over facilities used for the generation of electricity except as specifically provided. Thus, the Commission has no direct jurisdiction over fossil-fuel plants. Its jurisdiction extends only to the rates, terms, and conditions of wholesale sales and transmission of electric energy in interstate commerce from those plants. While we are aware that the legislative history of the CZMA indicates a Congressional intent to cover all federal activities, there is absolutely no indication in the CZMA or its legislative history that ''federal activities'' should include all federal regulatory decisions, including Commission orders involving interstate electric rates and service (or any other jurisdictional matter under Part II of the FPA).[1065] We are not aware of any judicial or agency interpretation that would cast the net of the states under the CZMA broadly enough to include the generic federal regulatory action undertaken in this Rule. Such action is clearly remote from the kind of activities such as leasing of land, and dredging and filling that either affect, or authorize specific activities that affect, the environment in the coastal zone.

Connecticut's attempt to pull FPA Part II regulation into the CZMA federal consistency provisions by dint of the rulemaking's alleged adverse impact on air quality and consequent adverse impact on water quality in the coastal zone is untenable in view of the existence of the Clean Air Act, a complex, 700-page environmental law that constitutes a comprehensive scheme of regulation of the Nation's air quality, including the direct regulation of emissions by utility power plants. Indeed, the CZMA provides that the requirements of the Clean Air Act, and governmental directives pursuant to that Act, shall be incorporated in, and shall be the air pollution control requirements of, all state coastal zone

[1061] Alliance at 62, *quoting* H.R. Rep. No. 474 (Part I) (Vol. 4), 103d Cong., 2d Sess. 132 (1992), *reprinted in* 1992 U.S. Code Cong. & Ad. News 1955.

[1062] For example, Title XVI concerned Global Climate Change.

[1063] *See, e.g.,* S. Rep. No. 228 (concerning the Clean Air Act Amendments of 1990), 101st Cong., 2d Sess. 5 (1990), *reprinted in* 1990 U.S. Code Cong. & Ad. News 3391 (''The States, together with EPA, are responsible for ensuring that the primary air quality standards are met * * *''); S. Rep. No. 228, 101st Cong., 2d Sess. 9, *reprinted in* 1990 U.S. Code Cong. & Ad. News 3395 (''The 1970 and 1977 Clean Air Act Amendments established a partnership between the States and Federal government. EPA sets nationally uniform air quality standards and States, with the Agency's assistance, are responsible for meeting them.''). *See also, e.g., Connecticut* v. *EPA,* 696 F.2d 147, 163 (2d Cir. 1982) (''One central focus of the Clean Air Act Amendments of 1977 was to ensure that the EPA would monitor and control the impact of pollution from one state on air quality in another.''); *Ohio Environmental Council* v. *EPA,* 593 F.2d 24, 31 (6th Cir. 1979) (''Congress placed responsibility for enforcing the Clean Air Act in the U.S. EPA.'').

We further note the following limitations on the Clean Air Act Amendments of 1990 with respect to the emission allowance program in section 403(f), which provides in pertinent part:

Nothing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges or affecting any State law regarding such State regulation or as limiting State regulation (including any prudency review) under such a State law. Nothing in this section shall be construed as modifying the Federal Power Act (16 U.S.C.A. 791a et seq.) or as affecting the authority of the Federal Energy Regulatory Commission under that Act. Nothing in this subchapter shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

42 U.S.C. 7651b(f). Thus, Congress expressly chose not to tie environmental authority under the emission allowance program to the Commission's and states' ratemaking authority.

[1064] The conference report on the 1990 CZMA amendments expressly states that the principal objective of the 1990 revisions to the language of section 307(c)(1) was to overturn a Supreme Court decision holding that Outer Continental Shelf oil and gas lease sales were not subject to CZMA consistency determinations. H.R. Rep. No. 101–964, 101st Cong., 2d Sess. 2675 (1990).

[1065] In using the phrase ''federal activities'' Congress did not use the term ''federal action'' which has clear and broad meaning under NEPA.

management programs.[1066] It therefore defies logic to assert that, despite the pervasive regulatory reach of the Clean Air Act and the clear authority of EPA to regulate NO_X emissions under that statute, the CZMA is a separate source of authority for state jurisdiction over air quality impacts to coastal zones.

While it is clear that Connecticut's invocation of the CZMA is incorrect, we note that, under the Commerce Department's implementing regulations, Connecticut has in any event waived its right to request a consistency determination for the Commission's rulemaking. Connecticut's coastal management program's list of federal agency activities likely to require a consistency determination does not (for good reason) describe rulemakings of this kind, and the rule will not ''result in a significant change in air or water quality within the management area'' (the program's catch-all category). In addition, Connecticut did not notify the Commission of its conclusion that the Rule requires a consistency determination until well after 45 days from receipt of several notices of the rulemaking proceeding.[1067] Consequently, pursuant to 15 CFR 930.35(b), Connecticut has in any event waived its right to request a consistency determination for this rulemaking.

Conclusion

After reviewing the record in this proceeding, including the FEIS, we find for the reasons discussed above that proceeding with this rule is the best alternative. No other alternative will accomplish the Commission's purposes.

The rule is expected to slightly increase or slightly decrease total future NO_X emissions, depending on whether competitive conditions in the electric industry favor the utilization of natural gas or coal as a fuel for the generation of electricity. Other impacts of the rule have also been determined to be slight. Therefore, it is unnecessary to adopt and implement a plan of mitigation.

A wide range of mitigation measures have nonetheless been fully evaluated as discussed in Chapter 7 of the FEIS. This discussion concludes that the Commission does not have authority under the FPA and NEPA, singly or conjointly, to impose mitigation, and that existing and proposed mitigation strategies and efforts are the best way to deal with potential environmental effects that might result from implementing the rule. Such effects, if they indeed materialize, are not expected to occur for many years. In the meantime, action by entities such as EPA and OTAG are expected to address the underlying air emission problems facing parts of the Nation. Interim mitigation efforts to be undertaken by the Commission would address only a very small part of the problem, would require the exercise of technical expertise and authority that the Commission does not possess, and could well interfere with efforts by EPA and others to address this situation.

For these reasons, we support the analysis in the staff's FEIS and adopt the conclusions in that document.[1068]

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA) [1069] requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. In the Open Access and Stranded Cost NOPRs, the Commission concluded that the proposed rules would not have a significant economic impact upon a substantial number of small entities.[1070]

SBA questions this conclusion.[1071] It states that, ''[a]ccording to data from the Department of Energy, the vast majority of utilities are small.'' [1072] SBA requests that if, upon reconsideration, the Commission determines that the final rule in the Open Access NOPR proceeding would have a significant economic impact on a substantial number of small entities, the Commission perform a Regulatory Flexibility Analysis under the requirements of the RFA.[1073]

A. Docket No. RM95–8–000 (Open Access Final Rule)

1. Public Utilities

The Open Access Final Rule is applicable to public utilities that own, control or operate interstate transmission facilities, not to electric utilities *per se*.[1074] The total number of public utilities that, absent waiver, would have to have open access tariffs on file is 166.[1075] Of these, only 50 public utilities dispose of 4 million MWh or less per year.[1076] Eliminating those utilities that are affiliates of other utilities whose sales exceed 4 million MWh per year, or are not independently owned,[1077] the total number of public utilities affected by the Open Access Final Rule that qualify under the SBA's definition of small electric utility is 19, or 11 percent of the total number of public utilities that would have to have on file open access tariffs.[1078] We do not consider this a substantial number,[1079] and, in any event, these entities may seek waiver of the Open Access Final

[1066] Section 307(f) of the CZMA, 16 U.S.C. 1456(f). A state may develop more stringent standards, if they can be enforced by the state (15 CFR 923.45(c)(2)), but more stringent state air quality standards would not alter the characteristics of FPA Part II regulation that put it beyond the federal consistency requirements of the CZMA.

[1067] The Connecticut Department of Environmental Protection is on the service list for the rulemaking proceeding. The Commission issued a NOPR in this proceeding on March 29, 1995 (60 FR 17662, April 7, 1995). On July 12, 1995, it issued a notice of intent to prepare an EIS in this proceeding (60 FR 36752, July 18, 1995). On November 17, 1995, the Commission issued a Draft EIS (60 FR 58304, Nov. 27, 1995).

[1068] A Record of Decision (ROD) will not be issued as a separate document; instead this rule, including the FEIS as incorporated into the rule by adoption, will serve as the ROD for the rule.

[1069] 5 U.S.C. 601–612.

[1070] 60 FR 17662 at 17721 (April 7, 1995), FERC Stats. & Regs. ¶ 32,514 at 33,151.

[1071] SBA Initial Comments at 1 and n.1.

[1072] SBA Initial Comments at 2 n.1. SBA ''defines a small electric utility as one that disposes of 4 million MWh of electricity in a given year.'' *Id.* At an average wholesale price of between $30 and $40 per MWh (Energy Information Administration, Financial Statistics of Major Investor-Owned Utilities, 1994, Table No. 1), utilities that dispose of 4 million MWh per year would have annual sales in the range of $120 million to $180 million.

[1073] 5 U.S.C. 601–612. SBA Initial Comments at 2 n.1.

[1074] The Stranded Cost Final Rule is applicable to public utilities and to transmitting utilities (that are not also public utilities).

[1075] Over 100 of these entities have already filed some type of open access tariff.

[1076] The sources for this figure are FERC Form No. 1 and FERC Form No. 1–F data.

[1077] The RFA defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6) and 15 U.S.C. 632(a)(1) (definition of ''small business concern'').

[1078] We note that five of these 19 public utilities have already filed open access tariffs with the Commission. While these five public utilities fall within SBA's definition of small electric utility, since they have already filed open access tariffs, the effect of the Open Access Final Rule on these entities should not be significant. The remaining 14 small public utilities constitute eight percent of the total number of public utilities that would have to have on file open access tariffs. To the extent these 14 small public utilities consider the impact of the Final Rule to be significant, these entities may request a waiver of the open access filing requirements under the waiver provisions of the Open Access Final Rule.

[1079] *In Mid-Tex Electric Coop., Inc.* v. *FERC*, 773 F.2d 327, 340–43 (D.C. Cir. 1985) (*Mid-Tex*), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the RFA, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to *all* public utilities. The Open Access Final Rule applies to *only* those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

Rule's requirements under the Rule's waiver provisions.

Moreover, in the Open Access Final Rule, the Commission is specifying the non-rate terms and conditions of the tariffs that the public utilities must have on file. The public utilities need only develop and file a rate.[1080] When one considers that the disposition of 4 million MWhs a year translates into sales in the range of $120 million to $180 million per year, the cost to prepare and file proposed rates,[1081] which these utilities must regularly do anyway in the ordinary course of business, is not a significant economic impact.

2. Non-Public Utilities

The Open Access Final Rule will not impose any burden on non-public utilities, since they need not themselves file open access tariffs. Triggering the reciprocity provision in the Open Access Final Rule is optional; it is merely a condition of receiving a benefit, *i.e.*, open access transmission service from a public utility. If non-public utilities elect not to take advantage of open access services because they do not want to meet the tariff reciprocity provision, they can still seek voluntary, bilateral transmission services from public utilities. Also, under the waiver provisions in the Open Access Final Rule, small non-public utilities may seek waiver from the reciprocity provision.

B. Docket No. RM94–7–001 (Stranded Cost Final Rule)

1. Public Utilities

As with the Open Access Final Rule, there are not a substantial number of public utilities that qualify under the SBA's definition of small electric utility that are subject to the Stranded Cost Final Rule. The Stranded Cost Rule applies only to public utilities that seek stranded cost recovery in connection with a limited set of wholesale requirements contracts (those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision). To the extent that public utilities seek stranded cost recovery, they will do so in a rate filing, where stranded cost recovery is likely to be one of many items considered. Accordingly, the Stranded Cost Final Rule will not pose a significant economic impact on a substantial number of public utility small entities.

2. Non-Public Utilities

With regard to non-public utilities, the stranded cost issue would only arise in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate. As with public utilities, stranded costs will be just one more item to be considered in establishing just and reasonable rates for transmission. As a result, the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities.

C. Conclusion

Accordingly, the Commission certifies that these final rules will not have a significant economic impact on a substantial number of small entities.

VII. Information Collection Statement

The Office of Management and Budget's (OMB) regulations [1082] require that OMB approve certain information and recordkeeping requirements (collections of information) imposed by an agency. Upon approval of a collection of information, OMB shall assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this Rule shall not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

There are now approximately 328 public utilities, including marketers and wholesale generation entities. The Commission estimates that 166 of these utilities own, control or operate facilities used for the transmission of electric energy in interstate commerce and would be subject to the filing requirements of this Rule.

Title: FERC–516, Electric Rate Schedule Filings.

Action: Final Rule.

OMB Control No: 1902–0096.

Respondents: Public Utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce.

Frequency of Responses: On occasion.

Necessity of information: The Final Rule requires public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to have on file with the Commission non-discriminatory open access transmission tariffs that contain minimum terms and conditions of service and permits public utilities to make filings to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services. The Commission has a mandate under sections 205 and 206 of the FPA to ensure, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, that no entity is subject to undue discrimination. The Commission will use the data collected in this collection of information to carry out its responsibilities under Part II of the FPA. The Commission's Office of Electric Power Regulation will use the data to review electric rate and tariff filings.

The Commission is submitting notification of this Final Rule to OMB. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC. 20426 [Attention: Michael Miller, Information Services Division, (202) 208–1415], and to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, (202) 395–3087).

VIII. Effective Date

This Rule will take effect on July 9, 1996. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this rule is a ''major rule'' within the meaning of section 351 of the Small Business Regulatory Enforcement Act of 1996.[1083] The rule will be submitted to both Houses of Congress and the Comptroller General prior to its publication in the Federal Register.

List of Subjects

18 CFR Part 35

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

18 CFR Part 385

Administrative practice and procedure, Electric power, Penalties, Pipelines, Reporting and recordkeeping requirements.

By the Commission. Commissioner Hoecker concurred in part and dissented in

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[1080] Those public utilities that already have open access tariffs on file are not even required to propose rates. They may elect to continue service under the Open Access Final Rule's non-rate terms and conditions at their existing rates.

[1081] In the Public Reporting Burden section (Section II), the Commission reaffirms the average reporting burden of 300 hours per response, which was proposed and unchallenged in the NOPR. If a cost of $200 per hour is used, the cost of making the required filing would be $60,000. On average, this is no more than one half of one percent of total annual sales for small electric utilities.

[1082] 5 CFR 1320.11.

[1083] 5 U.S.C. 804(2).

part with a separate statement attached. Commissioner Massey dissented in part with a separate statement attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends parts 35 and 385, chapter I, title 18 of the *Code of Federal Regulations,* as set forth below.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by revising § 35.15, by redesignating § 35.28 as § 35.29, and by adding new §§ 35.26, 35.27, and 35.28 to read as follows:

§ 35.15 Notices of cancellation or termination.

(a) *General rule.* When a rate schedule or part thereof required to be on file with the Commission is proposed to be cancelled or is to terminate by its own terms and no new rate schedule or part thereof is to be filed in its place, each party required to file the schedule shall notify the Commission of the proposed cancellation or termination on the form indicated in § 131.53 of this chapter at least sixty days but not more than one hundred-twenty days prior to the date such cancellation or termination is proposed to take effect. A copy of such notice to the Commission shall be duly posted. With such notice each filing party shall submit a statement giving the reasons for the proposed cancellation or termination, and a list of the affected purchasers to whom the notice has been mailed. For good cause shown, the Commission may by order provide that the notice of cancellation or termination shall be effective as of a date prior to the date of filing or prior to the date the filing would become effective in accordance with these rules.

(b) *Applicability.* (1) The provisions of paragraph (a) of this section shall apply to all contracts for unbundled transmission service and all power sale contracts:

(i) Executed prior to July 9, 1996; or

(ii) If unexecuted, filed with the Commission prior to July 9, 1996.

(2) Any power sales contract executed on or after July 9, 1996 that is to terminate by its own terms shall not be subject to the provisions of paragraph (a) of this section.

(c) *Notice.* Any public utility providing jurisdictional services under a power sales contract that is not subject to the provisions of paragraph (a) of this section shall notify the Commission of the date of the termination of such contract within 30 days after such termination takes place.

§ 35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) *Purpose.* This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) *Definitions.*

(1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) *Wholesale requirements customer* means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) *Wholesale transmission services* has the same meaning as provided in section 3(24) of the Federal Power Act (FPA): The transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

(4) *Wholesale requirements contract* means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) *Retail stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or transmitting utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility or transmitting utility.

(6) *Retail transmission services* means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) *New wholesale requirements contract* means any *wholesale requirements* contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

(8) *Existing wholesale requirements* contract means any *wholesale requirements* contract executed on or before July 11, 1994.

(c) *Recovery of wholesale stranded costs.*

(1) *General requirement.* A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) No public utility or transmitting utility may seek recovery of stranded costs associated with a new wholesale requirements contract if such contract does not contain an exit fee or other explicit stranded cost provision.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205–206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for FPA section 205 or 211 transmission services.

(iv) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing under the FPA made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through FPA section 205–206 rates for electric energy.

(B) If the contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(v)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to the customer.

(vi) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through FPA section 211–212 transmission rates.

(vii) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, *e.g.*, through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to that customer.

(2) *Evidentiary demonstration for wholesale stranded cost recovery.* A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1)(v)–(vii) of this section must demonstrate that:

(i) It incurred stranded costs on behalf of its wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream Estimate − Competitive Market Value Estimate)×Length of Obligation (reasonable expectation period).

(3) *Rebuttable presumption.* If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing wholesale requirements contract, as permitted in paragraph (c)(1) of this section, and the existing wholesale requirements contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(4) *Procedure for customer to obtain stranded cost estimate.* A customer under an existing wholesale requirements contract with a public utility seller may obtain from the seller an estimate of the customer's stranded cost obligation if it were to leave the public utility's generation supply system by filing with the public utility a request for an estimate at any time prior to the termination date specified in its contract.

(i) The public utility must provide a response within 30 days of receiving the request. The response must include:

(A) An estimate of the customer's stranded cost obligation based on the formula in paragraph (c)(2)(iii) of this section;

(B) Supporting detail indicating how each element in the formula was derived;

(C) A detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;

(D) An estimate of the amount of released capacity and associated energy that would result from the customer's departure; and

(E) The utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs.

(ii) If the customer disagrees with the utility's response, it must respond to the utility within 30 days explaining why it disagrees. If the parties cannot work out a mutually agreeable resolution, they may exercise their rights to Commission resolution under the FPA.

(5) A customer must be given the option to market or broker a portion or all of the capacity and energy associated with any stranded costs claimed by the public utility.

(i) To exercise the option, the customer must so notify the utility in writing no later than 30 days after the public utility files its estimate of stranded costs for the customer with the Commission.

(A) Before marketing or brokering can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount and the price of capacity and associated energy the customer is entitled to schedule, and the duration of the customer's marketing or brokering of such capacity and energy.

(ii) If agreement over marketing or brokering cannot be reached, and the parties seek Commission resolution of disputed issues, upon issuance of a Commission order resolving the disputed issues, the customer may reevaluate its decision in paragraph (c)(5)(i) of this section to exercise the marketing or brokering option. The customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

(iii) If a customer undertakes the brokering option, and the customer's brokering efforts fail to produce a buyer within 60 days of the date of the brokering agreement entered into between the customer and the utility, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula in paragraph (c)(2)(iii) of this section.

(d) *Recovery of retail stranded costs.*

(1) *General requirement.* A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) *Evidentiary demonstration necessary for retail stranded cost recovery.* A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) It incurred stranded costs on behalf of a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer; and

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility.

§ 35.27 Power sales at market-based rates.

(a) Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.

(b) Nothing in this part

(1) Shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or

(2) Limits the authority of a state commission in accordance with state and federal law to establish

(i) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(ii) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

§ 35.28 Non-discriminatory open access transmission tariff.

(a) *Applicability.* This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) *Definitions.*

(1) *Requirements service agreement* means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) *Economy energy coordination agreement* means a contract, or service schedule thereunder, that provides for trading of electric energy on an ''if, as and when available'' basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) *Non-economy energy coordination agreement* means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(c) *Non-discriminatory open access transmission tariffs.*

(1) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs) or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), and (c)(1)(iv) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996, it must file the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA, no later than July 9, 1996. However, if a public utility has already filed, or has on file, an open access tariff and accompanying rates as of April 24, 1996, it may, but is not required to, file new rates with its section 206 pro forma tariff filing.

(iii) If a public utility owns, controls or operates transmission facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file no later than December 31, 1996 the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

(iv) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the pro forma tariff required by this section.

(v) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs. ¶ 31,036.

(2) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access tariff filed pursuant to this section.

(i) Subject to the exceptions in paragraphs (c)(2)(ii) and (c)(3)(iv) of this section, this requirement is effective on the date that such public utility engages in a wholesale sale or purchase of electric energy or any unbundled retail sale of electric energy, but no earlier than July 9, 1996.

(ii) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(3) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must file a joint pool-wide or system-wide open access transmission pro forma tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after July 9, 1996, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any public utility holding company arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996, this requirement is effective July 9, 1996, except for the Central and South West System, which must comply no later than December 31, 1996.

(iii) For any power pool or multi-lateral arrangement or agreement other than a public utility holding company arrangement or agreement, that contains transmission rates, terms or conditions and that is executed prior to July 9, 1996, this requirement is effective on December 31, 1996.

(iv) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must begin to take service under a joint pool-wide or system-wide pro forma tariff for wholesale trades among the pool or system members no later than December 31, 1996.

(d) *Waivers.* A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶ 31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown. An application for waiver must be filed either:

(i) No later than July 9, 1996 or

(ii) No later than 60 days prior to the time the public utility would otherwise have to comply with the requirement.

(e) *Non-public utility procedures for tariff reciprocity compliance.*

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888 (Final Rule on Open Access and Stranded Costs).

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 case against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access tariff, for good cause shown. An application for waiver may be filed at any time.

PART 385—RULES OF PRACTICE AND PROCEDURE

1. The authority citation for part 385 continues to read as follows:

Authority: 5 U.S.C. 551–557; 15 U.S.C. 717–717z, 3301–3432; 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352; 49 U.S.C. 60502; 49 App. U.S.C. 1–85.

2. Part 385 is amended by adding paragraph (b)(5) to § 385.2011 to read as follows:

§ 385.2011 Procedures for filing on electronic media (Rule 2011).

* * * * *

(b) * * *

(5) Non-discriminatory open access transmission tariffs filed pursuant to § 35.28 of this chapter.

* * * * *

Note: Appendices A through H and statements of Commissioners Hoecker and Massey will not be published in the Code of Federal Regulations.

LIST OF SECTION 211 APPLICATIONS

No.	Docket No.	Applicant	Transmitter	Commission action
1	TX93–1–000	Tex-La Electric Cooperative of Texas, Inc.	Texas Utilities Electric Company	Denied, 64 FERC ¶ 61,162.
2	TX93–2–000	City of Bedford, Virginia, et al	American Electric Power Company, Inc.	Granted. Final order, 68 FERC ¶ 61,003. Reh'g denied, 73 FERC ¶ 61,322.
3	TX93–3–000	Wisconsin Electric Power Company	Upper Peninsula Power Company	Withdrawn 9/10/93.
4	TX93–4–000	Florida Municipal Power Agency	Florida Power & Light Company	Granted. Final order, 67 FERC ¶ 61,167. Order on reh'g, 74 FERC ¶ 61,006.
5	TX94–1–000	Minnesota Municipal Power Agency	Northern States Power Company	Granted. Proposed order, 66 FERC ¶ 61,114. Reh'g denied, 66 FERC ¶ 61,323 Settlement accepted by letter order, 68 FERC ¶ 61,031.
6	TX94–2–000	El Paso Electric Company, et al	Southwestern Public Service Company	Proposed order, 68 FERC ¶ 61,182; order on reh'g, 68 FERC ¶ 61,399; order dismiss'g proceeding, 72 FERC ¶ 61,292.
7	TX94–3–000	Minnesota Municipal Power Agency	Southern Minnesota Municipal Power Agency.	Granted. Proposed order, 66 FERC ¶ 61,223; reh'g denied, 67 FERC ¶ 61,075; Final order, 68 FERC ¶ 61,060.
8	TX94–4–000	Tex-La Electric Cooperative of Texas, Inc.	Texas Utilities Electric Company	Granted. Proposed order, 67 FERC ¶ 61,019; Final order, 69 FERC ¶ 61,269.
9	TX94–5–000	Old Dominion Electric Cooperative, Inc	Delmarva Power & Light Company	Granted. Proposed order, 68 FERC ¶ 61,169. Settl'd, 69 FERC ¶ 61,436, 70 FERC ¶ 61,082.
10	TX94–6–000	Reading Municipal Light Department	16 New England Transmitting Utilities	Terminated July 10, 1995 by OEPR Letter Order, following notice of withdrawal filed May 8, 1995.
11	TX94–7–000	AES Power, Inc	Tennessee Valley Authority	Granted. Final Order issued Feb. 29, 1996, 74 FERC ¶ 61,220, reh'g pending.
12	TX94–8–000	Duquesne Light Company	PJM Companies	Granted. Proposed order issued 5/16/95, 71 FERC ¶ 61,155.
13	TX94–9–000	Borough of Zelienople, Pennsylvania	Pennsylvania Power Company	Granted. Proposed order issued 1/25/95, 70 FERC ¶ 61,073.
14	TX94–10–000	Duquesne Light Company	Allegheny Power System	Granted. Proposed order issued 5/16/95, 71 FERC ¶ 61,156.
15	TX95–1–000	Enron Power Marketing, Inc	Consolidated Edison Co. of New York	Pending. Comments due 11/3/94.
16	TX95–2–000	Wisconsin Public Power Inc. SYSTEM	WEPCO, WP&L, WPSC	Pending. Comments due 11/16/94.
17	TX95–3–000	Municipal Energy Agency of Nebraska	Nebraska Public Power District and Tri-State Generation and Transmission Association, Inc.	w/drawn 11–16–95
18	TX95–4–000	American Municipal Power-Ohio, Inc	Ohio Edison Company	Granted. Proposed Order issued Feb. 1, 1996 74 FERC ¶ 61,086.
19	TX95–5–000	United States Department of Energy—Southeastern Power Administration.	Southern Company System	Pending.
20	TX95–6–000	Cleveland Public Power	Centerior Energy Corporation	Rejected Without Prejudice 72 FERC ¶ 61,189.
21	TX95–7–000	Cleveland Public Power	Cleveland Electric Illuminating Company and Toledo Edison Company.	Pending.
22	TX96–1–000	Citizens Utilities Company	Swanton Village, Vermont	Pending.

LIST OF SECTION 211 APPLICATIONS—Continued

No.	Docket No.	Applicant	Transmitter	Commission action
23	TX96–2–000	City of College Station, Texas	City of Bryan, Texas and Texas Municipal Power Agency.	Pending.
24	TX96–3–000	Citizens Utilities Company	Swanton Village, Vermont	Pending.
25	TX96–4–000	Suffolk County Electrical Agency	Long Island Lighting Company	Pending.
26	TX96–5–000	United States Department of Energy—Western Area Power Administration.	Public Service Company of New Mexico.	Pending.
27	TX96–6–000	Montana Power Company	Basin Electric Cooperative	Pending.
28	TX96–7–000	City of Palm Springs, California	Southern California Edison Company	Pending.

Appendix B—List of Commenters

Abbreviation	Commenter
1. ABATE	Association of Businesses Advocating Tariff Equity.
2. AEC & SMEPA	Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association.
3. AEP	American Electric Power System.
4. AGA	American Gas Association.
5. Air Liquide	Air Liquide America Corporation.
6. AL Com	Alabama Public Service Commission.
7. ALCOA	Aluminum Company of America.
8. Allegheny	Allegheny Power Service Corporation.
9. Alma	City of Alma, Michigan.
10. Aluminum	Aluminum Association.
11. American Forest & Paper	American Forest & Paper Association.
12. American Iron & Steel	American Iron & Steel Institute American Forest & Paper Association, American Public Power Association, Chemical Manufacturers Association, Citizen Action, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, Environmental Action Foundation, City of Las Cruces, New Mexico, City of Westbrook, Maine, Sovereign California Cities Joint Powers Committee, Toward Utility Rate Normalization.
13. American National Power	American National Power, Inc.
14. American Wind	American Wind Energy Association.
15. AMP-Ohio	American Municipal Power-Ohio, Inc. and Indiana Municipal Power Agency.
16. Anaheim	Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.
17. Anchorage	Anchorage Municipal Light and Power.
18. Anoka EC	Anoka Electric Cooperative.
19. APPA	American Public Power Association.
20. APS Customers	APS Wholesale Customer Group (Aquila Irrigation District, Buckeye Water Conservation District, Electrical District No. 3 of Pinal County, Electrical District No. 6 of Pinal County, Electrical District No. 7 of Maricopa County, Electrical District No. 8 of Maricopa County, Harquahala Valley Power District, Maricopa County Municipal Water Conservation District No. 1, McMullan Valley Water Conservation District, Roosevelt Irrigation District and Tonopah Irrigation District).
21. Arcadia	Arcadia Resources, Inc.
22. Arizona	Arizona Public Service Company.
23. Arizona EC	Arizona Electric Power Cooperative.
24. Ark Elec	Arkansas Electric Cooperative Corporation.
25. Arkansas Cities	Arkansas Cities and Farmers Electric Cooperative.
26. Associated EC	Associated Electric Cooperative, Inc.
27. Associated Power	Associated Power Services, Inc.
28. Atlantic City	Atlantic City Electric Company.
29. AZ Com	Arizona Corporation Commission.
30. Baker EC	Baker Electric Cooperative, Inc.
31. Baltimore Transp Bureau	Transportation Bureau of Baltimore, Inc.
32. Basin EC	Basin Electric Power Cooperative.
33. BG&E	Baltimore Gas and Electric Company.
34. Big Horn REC	Big Horn Rural Electric Company.
35. Big Rivers EC	Big Rivers Electric Cooperative.
36. Black Hills EC	Black Hills Electric Cooperative.
37. Black Mayors	National Conference of Black Mayors.
38. Blue Ridge	Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc.
39. Bon Homme Yankton EC	Bon Homme Yankton Electric Association, Inc.
40. Boston Edison	Boston Edison Company.
41. Boulder	City of Boulder, Colorado.
42. BPA	Bonneville Power Administration.
43. Brazos	Brazos Electric Power Cooperative, Inc.
44. Brownsville	Brownsville, Texas Public Utilities Board.
45. Building Owners	Building Owners and Managers Association International.
46. CA Cogen	Cogeneration Association of California.
47. CA Com	California Public Utilities Commission.

Abbreviation	Commenter
48. CA Energy Co	California Energy Company, Inc.
49. CA Energy Com	California Energy Commission.
50. Cajun	Cajun Electric Power Cooperative, Inc.
51. California DWR	California Department of Water Resources.
52. California Water Agencies	Association of California Water Agencies.
53. Calpine	Calpine Corporation.
54. CAMU	Colorado Association of Municipal Utilities.
55. Canada	Canadian Embassy.
56. Canadian Petroleum Producers	Canadian Association of Petroleum Producers.
57. Caparo	Caparo Steel.
58. Carbon Power	Carbon Power & Light Inc.
59. Carolina P&L	Carolina Power & Light Company.
60. CCEM	Coalition for a Competitive Electric Market (consisting of Catex Vitol Electric, Inc., Coastal Electric Services Company, Destec Power Services, Inc., Electric Clearinghouse, Inc., Enron Power Marketing, Inc., Equitable Power Services Company, KCS Power Marketing, Inc. and MidCon Power Services Corp.).
61. Centerior	Centerior Energy Corporation.
62. Central EC	Central Electric Power Cooperative.
63. Central Hudson	Central Hudson Gas & Electric Corporation.
64. Central Illinois Light	Central Illinois Light Company.
65. Central Illinois Public Service	Central Illinois Public Service Company.
66. Central Louisiana	Central Louisiana Electric Company, Inc.
67. Central Montana EC	Central Montana Electric Power Cooperative, Inc.
68. Christensen	Laurits R. Christensen Associates Inc.
69. Chugach	Chugach Electric Association, Inc.
70. CINergy	CINergy Corp.
71. Citizens Lehman	Citizens Lehman Power L.P.
72. Citizens Utilities	Citizens Utilities Company.
73. Clark	Clark Public Utilities.
74. Clean Air	Clean Air Action Corporation.
75. Cleveland	Cleveland Public Power.
76. CO Com	Colorado Public Utilities Commission Staff.
77. CO Consumers Counsel	Colorado Office of Consumer Counsel.
78. Coalition for Economic Competition	Coalition for Economic Competition (consisting of Central Hudson Gas & Electric Corporation, Central Maine Power Company, Consolidated Edison Company of New York, Inc., Illinois Power Company, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.
79. Coalition on Federal-State Issues	Coalition on Federal-State Issues of the Power Marketing Association.
80. Com Ed	Commonwealth Edison Company.
81. Com Electric	Commonwealth Electric Company.
82. Competitive Enterprise	Competitive Enterprise Institute.
83. Concord	Concord Municipal Light Plant.
84. ConEd	Consolidated Edison Company of New York, Inc.
85. Conservation Law Foundation	Conservation Law Foundation and Center for Efficiency and Renewable Technologies.
86. Consolidated Natural Gas	Consolidated Natural Gas Company.
87. Consumers Power	Consumers Power Company.
88. Continental Power Exchange	Continental Power Exchange, Inc.
89. Cooperative Power	Cooperative Power.
90. CSW	Central and South West Corporation.
91. CT DPUC	Connecticut Department of Public Utility Control.
92. CT Munis	Connecticut Conference of Municipalities.
93. CVPSC	Central Vermont Public Service Corporation.
94. Dairyland	Dairyland Power Cooperative.
95. Dayton P&L	Dayton Power and Light Company.
96. DC Com	Public Service Commission of the District of Columbia.
97. DE Muni	Delaware Municipal Electric Corporation, Inc.
98. DE, DC, NJ and MD Coms	Delaware Public Service Commission, District of Columbia Public Service Commission, Maryland Public Service Commission, and New Jersey Board of Public Utilities.
99. Deloitte & Touche	Deloitte & Touche LLP.
100. Destec	Destec Energy.
101. Detroit Edison	Detroit Edison Company.
102. Detroit Edison	Detroit Edison Wholesale Customers (consisting of City of Croswell, Michigan, and Thumb Electric Cooperative).
103. Direct Service Industries	Direct Service Industries (consisting of ELF Atochem North America, Inc., Columbia Columbia Aluminum Corporation, Columbia Falls Aluminum Co., Georgia Pacific, Kaiser Aluminum & Chemical Corporation, Intalco Aluminum, Northwest Aluminum Company, Reynolds Metals Company and Vanalco, Inc.).
104. DOD	Department of Defense.
105. DOE	United States Department of Energy.
106. DOJ	United States Department of Justice.
107. Dominion	Dominion Resources.
108. Douglas EC	Douglas Electric Cooperative, Inc.
109. Duke	Duke Power Company.

Abbreviation	Commenter
110. Duquesne	Duquesne Light Company.
111. East Kentucky	East Kentucky Power Cooperative, Big Rivers Electric Corporation, and Hoosier Energy Rural Electric Cooperative.
112. East River EC	East River Electric Power Cooperative.
113. EDS Utilities	Electronic Data Systems Inc., Utilities Division (Joussef Heguzy, Clifford J. Meagh, Julius A. Wright).
114. Education	American Council on Education and the National Association of College and University Business Officers
115.	EEI Edison Electric Institute.
116. EGA	Electric Generation Association.
117. El Paso	El Paso Electric Company.
118. ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, Chemical Manufacturers Association and Council of Industrial Boiler Owners.
119. Electric Consumers Alliance	Electric Consumers' Alliance.
120. Electronic Data Systems	EDS Utilities Division (James F. Susman).
121. ENEREX	ENEREX, Inc.
122. Entergy	Entergy Services, Inc.
123. Entergy Retail Regulators	Arkansas Public Service Commission, City Council of New Orleans, Louisiana Public Service Commission, and Mississippi Public Service Commission.
124. Environmental Action	Environmental Action Foundation.
125. EPA	United States Environmental Protection Agency.
126. Fertilizer Institute	The Fertilizer Institute.
127. FL Com	Florida Public Service Commission.
128. Florida Power Corp	Florida Power Corporation.
129. FPL	Florida Power & Light Company.
130. Freedom Energy Co	Freedom Energy Company, LLC.
131. FTC	United States Federal Trade Commission, Staff of the Bureau of Economics.
132. Fuel Managers	Fuel Managers Association.
133. GA Com	Georgia Public Service Commission.
134. GAPP Committee	General Agreement of Parallel Paths Committee (A. Garfield).
135. Graves	Graves, Frank and Ilic, Marija.
136. Green Mountain	Green Mountain Power Corporation.
137. Heartland	Heartland Consumers Power District.
138. Hogan	Hogan, William W.
139. Home Builders	National Association of Home Builders.
140. Homelessness Alliance	National Alliance to End Homelessness, Inc.
141. Hoosier EC	Hoosier Energy Rural Electric Cooperative.
142. Hopkinsville EC	Hopkinsville Electric System.
143. Houston L&P	Houston Lighting & Power Company.
144. Hydro-Quebec	Hydro-Quebec.
145. IA Com	Iowa Utilities Board.
146. IBM	International Business Machines.
147. ID Com	Idaho Public Utilities Commission.
148. Ida County REC	Ida County Rural Electric Cooperative.
149. Idaho	Idaho Power Company.
150. IES Utilities	IES Utilities Inc.
151. IL Com	Illinois Commerce Commission.
152. IL Industrials	Illinois Industrial Energy Consumers.
153. Illinois Municipal Electric Agency	Illinois Municipal Electric Agency.
154. Illinois Power	Illinois Power Company.
155. IN Com	Indiana Utility Regulatory Commission.
156. IN Industrials	Indiana Industrial Energy Consumers, Inc.
157. Industrial Energy Applications	Industrial Energy Applications.
158. Inland Power Pool	Inland Power Pool.
159. IPALCO	IPALCO Enterprises, Inc.
160. James Valley EC	James Valley Electric Cooperative, Inc.
161. Jay	Town of Jay, Maine and the Jay Power District.
162. KCPL	Kansas City Power & Light Company.
163. Knoxville	Knoxville Utilities Board.
164. KS Com	Kansas Corporation Commission Staff.
165. KU	Kentucky Utilities Company.
166. KY AG	Kentucky Attorney General.
167. KY Com	Kentucky Public Service Commission.
168. LA DWP	Department of Water and Power of the City of Los Angeles.
169. LA Industrials	Louisiana Energy Users Group.
170. La Raza	National Council of La Raza.
171. Las Cruces	City of Las Cruces, New Mexico.
172. Latin League	League of United Latin American Citizens.
173. Legal Environmental Assistance	Legal Environmental Assistance Foundation.
174. LEPA	Louisiana Energy and Power Authority.
175. Lester Fink	Fink, Lester.
176. LG&E	LG&E Energy Corp.
177. LILCO	Long Island Lighting Company.
178. Lincoln-Union EC	Lincoln-Union Electric Company.

Abbreviation	Commenter
179. Lively	Lively, Mark B.
180. Local Furnishing Utilities	Local Furnishing Utilities (Long Island Lighting Company, Nevada Power Company, and San Diego Gas & Electric Company).
181. Lower Colorado River Authority	Lower Colorado River Authority.
182. LPPC	Large Public Power Council.
183. MA DPU	Massachusetts Department of Public Utilities.
184. Madison G&E	Madison Gas & Electric Company.
185. Maine Public Service	Maine Public Service Company.
186. Maritime	Maritime Electric Company.
187. McKenzie EC	McKenzie Electric Cooperative, Inc.
188. MD Com	Maryland Public Service Commission.
189. ME Consumer-Owned Utilities	Maine Consumer-Owned Utilities (consisting of Eastern Maine Electric Cooperative, Inc., Fox Islands Electric Cooperative, Inc. Houlton Water Company, Isle au Haut Electric Power Co., Kennebunk Light & Power District, Madison Electric Works, Swans Island Electric Cooperative, Inc., and Van Buren Light & Power District).
190. ME Industrials	Industrial Energy Consumer Group of Maine.
191. MEAG	Municipal Electric Authority of Georgia.
192. Memphis	Memphis Light, Gas and Water Division.
193. Mercer	Mercer, Dorothy Ph.D.
194. MI Com	Michigan Public Service Commission.
195. MI MEA	Municipal Energy Agency of Mississippi.
196. Michigan Coalition	Consumers Power, Detroit Edison and Michigan Public Service Commission.
197. Michigan Systems	Florida Municipal Power Agency, Michigan Public Power Agency, Michigan South Central Power Agency, Michigan Public Power Ratepayers Association and Wolverine Power Supply Cooperative.
198. MidAmerican	MidAmerican Energy Company.
199. Midwest Commissions	Arkansas, Kansas & Missouri State Commissions.
200. Minnesota P&L	Minnesota Power & Light Company.
201. Missouri Basin Group	Missouri Basin Systems Group, Inc.
202. Missouri Basin MPA	Missouri Basin Municipal Power Agency.
203. Missouri Joint Commission	Missouri Joint Municipal Electric Utilities Commission.
204. Missouri-Kansas Industrials	Missouri-Kansas Industrial Energy Consumers.
205. MMWEC	Massachusetts Municipal Wholesale Electric Company.
206. MN DPS	Minnesota Department of Public Service.
207. Montana Power	Montana Power Company.
208. Montana-Dakota Utilities	Montana-Dakota Utilities Company.
209. Montaup	Montaup Electric Company.
210. Mor-Gran-Sou EC	Mor-Gran-Sou Electric Cooperative.
211. Mountain States Petroleum Assoc	Independent Petroleum Association of Mountain States and Colorado Oil and Gas Association.
212. MS Com	Mississippi Public Service Commission.
213. MT Com	Montana Public Service Commission.
214. MT Dept of Environmental Quality	Montana Department of Environmental Quality.
215. Mt. Hope Hydro	Mt. Hope Hydro, Inc.
216. Municipal Energy Agency Nebraska	Municipal Energy Agency of Nebraska.
217. NARUC	National Association of Regulatory Utility Commissioners.
218. NASUCA	National Association of State Utility Consumer Advocates.
219. National Hydropower	National Hydropower Association.
220. National Women's Caucus	National Women's Political Caucus.
221. Natural Resources Defense	Natural Resources Defense Council and Pacific Gas and Electric Company.
222. NC Com	North Carolina Utilities Commission.
223. NCMPA	North Carolina Municipal Power Agency Number 1.
224. NCPA	Northern California Power Agency.
225. ND Com	North Dakota Public Service Commission.
226. NE Public Power District	Nebraska Public Power District.
227. NE States Air Management	Northeast States for Coordinated Air Use Management.
228. NEPCO	New England Power Company.
229. NEPOOL	New England Power Pool Executive Committee.
230. NEPOOL Review Committee	New England Public Power NEPOOL Review Committee.
231. NERC	North American Electric Reliability Council.
232. Nevada	Nevada Power Company.
233. New Brunswick	New Brunswick Power.
234. NGSA	Natural Gas Supply Association.
235. NH Com	New Hampshire Public Utilities Commission.
236. NH General Court	Retail Wheeling & Restructuring Committee of the New Hampshire General Court.
237. NIEP	National Independent Energy Producers.
238. NIMO	Niagara Mohawk Power Corporation.
239. NIPSCO	Northern Indiana Public Service Company.
240. NJ BPU	New Jersey Board of Public Utilities.
241. NJ Ratepayer Advocate	New Jersey Division of the Ratepayer Advocate.
242. NM Com	New Mexico Public Utility Commission.
243. NM Industrials	New Mexico Industrial Energy Consumers.
244. NorAm	NorAm Energy Services, Inc.
245. Nordhaus	Nordhaus, William D.
246. North Dakota RECs	North Dakota Association of Rural Electric Cooperatives.

Abbreviation	Commenter
247. NRECA	National Rural Electric Cooperative Association.
248. NRECA/APPA	National Rural Electric Cooperative Association and APPA.
249. NRRI	National Regulatory Research Institute.
250. NSP	Northern States Power Company.
251. NU	Northeast Utilities System Companies.
252. Nuclear Energy Institute	Nuclear Energy Institute.
253. Nucor	Nucor Corporation.
254. NV Com	Public Service Commission of Nevada.
255. NW Conservation Act Coalition	Northwest Conservation Act Coalition.
256. NW Iowa Cooperative	Northwest Iowa Power Cooperative.
257. NW Power Planning Council	Northwest Power Planning Council.
258. NWRTA	Northwest Regional Transmission Association.
259. NY AG	New York State Attorney General.
260. NY Com	Public Service Commission of the State of New York.
261. NY Consumer Protection	New York Consumer Protection Board.
262. NY Energy Buyers	New York Energy Buyers Forum.
263. NY Industrials	Multiple Industrial Intervenors of New York.
264. NY IOUs	Long Island Lighting, New York State Electric & Gas and Rochester Gas & Elec.
265. NY Mayors	New York State Conference of Mayors and Municipal Officals.
266. NYMEX	New York Mercantile Exchange.
267. NYPP	New York Power Pool.
268. NYSEG	New York State Electric & Gas Corporation.
269. Oahe EC	Oahe Electric Cooperative, Inc.
270. Oak Ridge	Oak Ridge National Laboratory.
271. Occidental Chemical	Occidental Chemical Corporation.
272. Oglethorpe	Oglethorpe Power Corporation.
273. OH Com	Public Utilities Commission of Ohio.
274. OH Coops	Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.
275. OH Industrials	Industrial Energy Users—Ohio.
276. Ohio Edison	Ohio Edison Company.
277. Ohio Manufacturers	Ohio Manufacturers' Association.
278. Ohio Valley	Ohio Valley Electric Corporation.
279. OK Com	Oklahoma Corporation Commission.
280. Oklahoma G&E	Oklahoma Gas and Electric Company.
281. Old Dominion EC	Old Dominion Electric Cooperative, Inc.
282. Oliver-Mercer EC	Oliver-Mercer Electric Cooperative, Inc.
283. Omaha PPD	Omaha Public Power District.
284. Ontario Hydro	Ontario Hydro.
285. Orange & Rockland	Orange and Rockland Utilities, Inc.
286. Oregon Trail EC	Oregon Trail Electric Cooperative, Inc.
287. Otter Tail	Otter Tail Power Company.
288. PA Com	Pennsylvania Public Utility Commission.
289. PA Coops	Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc.
290. PA Industrials	Industrial Energy Consumers of Pennsylvania.
291. PA Munis	Pennsylvania Municipal Electric Association.
292. Pacific Northwest Coop	Pacific Northwest Generating Cooperative.
293. PacifiCorp	PacifiCorp.
294. Panhandle Coop	Panhandle Rural Electric Membership Association.
295. PECO	PECO Energy Company.
296. Pennsylvania P&L	Pennsylvania Power & Light Company.
297. PG&E	Pacific Gas and Electric Company.
298. Phelps Dodge	Phelps Dodge Corporation.
299. Philip Morris	Philip Morris Management Corp.
300. PJM	PJM—Pennsylvania New Jersey Maryland Interconnection.
301. Portland	Portland General Electric Company.
302. Power Marketing Association	Power Marketing Association.
303. PSE&G	Public Service Electric and Gas Company.
304. PSNM	Public Service Company of New Mexico.
305. Public Generating Pool	Public Generating Pool.
306. Public Power Council	Public Power Council.
307. Public Service Co of CO	Public Service Company of Colorado and Cheyenne Light, Fuel and Power Company.
308. Puget	Puget Sound Power & Light Company.
309. Redding	Cities of Redding and Santa Clara, California.
310. Reynolds	Reynolds Metals Company.
311. Rochester G&E	Rochester Gas and Electric Corporation.
312. Rocky Mountain Institute	Rocky Mountain Institute (Amory Lovins).
313. Rosebud	Rosebud Enterprises, Inc.
314. RUS	Rural Utilities Service (formerly REA).
315. Rushmore EC	Rushmore Electric Power Cooperative, Inc.
316. Salt River	Salt River Project Agriculture Improvement and Power District.
317. San Diego G&E	San Diego Gas & Electric Company.
318. San Francisco	City and County of San Francisco.
319. San Luis Valley REC	San Luis Valley Rural Electric Cooperative.
320. SBA	United States Small Business Administration, Office of Advocacy.

Abbreviation	Commenter
321. SC Com	South Carolina Public Service Commission.
322. SCE&G	South Carolina Electric & Gas Company.
323. SC Public Service Authority	South Carolina Public Service Authority.
324. Seattle	Seattle City Light Department.
325. Seminole EC	Seminole Electric Cooperative, Inc.
326. SEPA	Southeastern Power Administration/Federal Power Customers.
327. Shelby County	Shelby County Board of Commissioners.
328. Sierra	Sierra Pacific Power Company.
329. Slope EC	Slope Electric Cooperative Inc.
330. SMUD	Sacramento Municipal Utility District.
331. Snohomish	Public Utility District No. 1 of Snohomish County, Washington.
332. SoCal Edison	Southern California Edison Company.
333. SoCal Gas	Southern California Gas Company.
334. South Jersey Gas	South Jersey Gas Company.
335. Southern	Southern Company Services, Inc.
336. Southwest TDU Group	Southwest Transmission Dependent Utility Group (consisting of Aguila Irrigation District, Ak-Chin Indian Community, Buckeye Irrigation District, Central Arizona Water Conservation District, Electrical District No. 3, No. 4, No. 5, No. 6, No. 7, Harquahala Valley Power District, Maricopa Water District, McMullen Valley Water Conservation and Drainage District, City of Needles, Roosevelt Irrigation District, City of Safford, Tonopah Irrigation District, Wellton-Mohawk Irrigation and Drainage District).
337. Southwestern	Southwestern Public Service Company.
338. Soyland	Soyland Power Cooperative.
339. Spink EC	Spink Electric, Redfield, SD.
340. SPP	Southwest Power Pool, Inc.
341. Springfield	City Utilities of Springfield, Missouri.
342. St. Joseph	St. Joseph Light & Power Company.
343. Suffolk County	Suffolk County (New York) Electric Agency.
344. Sunflower	Sunflower Electric Power Corporation.
345. Supervised Housing	State and City Supervised Housing for Equity in Electric Rates.
346. Sustainable Energy Policy	Project For Sustainable FERC Energy Policy (on behalf of Alliance for Affordable Energy, Citizens Action Coalition of Indiana, Conservation Law Foundation, Environmental Defense Fund, Environmental Law & Policy Center of the Midwest, Izaak Walton League of America, Land and Water Fund of the Rockies, Legal Environmental Assistance Foundation, Mid-Atlantic Energy Project, Minnesotans for an Energy-Efficient Economy, Natural Resources Defense Council, Northwest Conservation Act Coalition, Pace Energy Project, Public Citizen, Texas, RENEW Wisconsin, Southern Environmental Law Center, Texas Ratepayers' Organization to Save Energy, Union of Concerned Scientists, and Wisconsin's Environmental Decade).
347. Tallahassee	City of Tallahassee, Florida.
348. Tampa	Tampa Electric Company.
349. TANC	Transmission Agency of Northern California.
350. TAPS	Transmission Access Policy Study Group.
351. TDU Systems	Transmission Dependent Utility Systems (Arkansas Electric Cooperative Corporation, Connecticut Municipal Electric Energy Cooperative, Golden Spread Electric Cooperative, Inc., Holy Cross Electric Association, Inc., Kansas Electric Power Cooperative, Inc., Magic Valley Electric Cooperative, Inc., Mid-Tex Generation & Transmission Electric Cooperative, Inc., NewCorp Resources, Inc., Old Dominion Electric Cooperative, Inc.).
352. Texaco	Texaco Inc.
353. Texas Utilities	Texas Utilities Electric Company.
354. Texas-New Mexico	Texas-New Mexico Power Company.
355. Tonko	Tonko, Paul D. (NY State Assembly).
356. Torco	Torco Energy Marketing, Inc.
357. Total Petroleum	Total Petroleum, Inc.
358. Traverse EC	Traverse Electric Cooperative, Inc.
359. Tri-County EC	Tri-County Electric Association, Inc.
360. Tri-State G&T	Tri-State Generation and Transmission Association, Inc.
361. Tucson Power	Tucson Electric Power Company.
362. Turlock	Turlock Irrigation District.
363. Turner-Hutchinson EC	Turner-Hutchinson Electric Cooperative, Inc.
364. TVA	Tennessee Valley Authority.
365. TX Com	Public Utility Commission of Texas.
366. TX Industrials	Texas Industrial Energy Consumers.
367. UAMPS	Utah Associated Municipal Power Systems.
368. Union County EC	Union County Electric Cooperative, Inc.
369. Union Electric	Union Electric Company.
370. United Illuminating	United Illuminating Company.
371. UNITIL	UNITIL Corporation.
372. Urban League	Greater Washington Urban League, Inc.
373. UT Com	Utah Public Service Commission and Utah Division of Public Utilities.
374. UT Industrials	Utah Industrial Energy Consumers (consisting of Alliant Techsystems, Inc., Amoco Oil Company, Holnam, Inc., Kennecott Copper Corp., and Western Zirconium.
375. UtiliCorp	UtiliCorp United Inc.

Abbreviation	Commenter
376. Utilities For Improved Transition	Utilities For an Improved Transition (consisting of Basin Electric Cooperative, Black Hills Corporation, Boston Edison Company, Central Vermont Public Service Corporation, Montaup Electric Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation).
377. Utility—Trade Corp. Utility—Trade Corp..	
378. Utility Investors Analysts	Utility Investors and Analysts.
379. Utility Shareholders	United Utility Shareholders Association of America.
380. Utility Wind Interest Group	Utility Wind Interest Group, Inc.
381. Utility Workers Union	Utility Workers Union of America, AFL–CIO.
382. Utility Working Group	Utility Working Group (consisting of Atlantic City Electric Company, Dominion Resources, Inc., Duke Power Company, Florida Power & Light Company, Niagara Mohawk Power Corporation, Pacific Gas and Electric Company, Public Service Electric and Gas Company, and San Diego Gas & Electric Company).
383. VA Com	Staff of the Virginia State Corporation Commission.
384. Vann	Vann, Albert (NY State Assembly).
385. VEPCO	Virginia Electric and Power Company.
386. Verendrye EC	Verendrye Electric Cooperative, Inc.
387. Vernon	City of Vernon, California.
388. VT DPS	Vermont Department of Public Service.
389. WA Com	Washington Utilities and Transportation Commission.
390. Wabash	Wabash Valley Power Association, Inc.
391. WAPA	Western Area Power Administration and Department of Energy.
392. Washington and Oregon Energy Offices	Washington State Energy Office and Oregon Department of Energy.
393. Washington Water Power	Washington Water Power Company Energy Offices.
394. WEPCO	Wisconsin Electric Power Company.
395. West River EC	West River Electric Association, Inc.
396. Western Resources	Western Resources Inc.
397. Whetstone Valley EC	Whetstone Valley Electric Cooperative, Inc.
398. WI Com	Public Service Commission of Wisconsin.
399. Wing Group	Wing Group.
400. Wisconsin Coalition	Wisconsin Coalition (Wisconsin Public Power Incorporated System, Municipal Electric Utilities of Wisconsin, Madison Gas and Electric Company, and Citizens' Utility Board of Wisconsin).
401. Wisconsin EC	Wisconsin Electric Cooperative Association.
402. Wisconsin Municipals	Municipal Electric Utilities of Wisconsin.
403. Wollenberg	Wollenberg, Bruce, et al.
404. Wolverine Coop Members	Wolverine Power Supply Cooperative Special Members Committee.
405. Woodbury County REC	Woodbury County Rural Electric Cooperative.
406. WP&L	Wisconsin Power and Light Company.
407. WSCC	Western Systems Coordinating Council Board of Trustees.
408. WSPP	Western Systems Power Pool.
409. Yellowstone Valley EC	Yellowstone Valley Electric Cooperative, Inc.

Environmental Impact Commenters

1. Attorneys General of Massachusetts, Connecticut, New Jersey and Vermont
2. Center for Clean Air Policy
3. Central Maine Power Company
4. Cincinnati Gas & Electric Company and PSI Energy, Inc.
5. Clifton Below
6. Electric Consumer's Alliance
7. Connecticut Siting Council
8. Southern Environmental Law Center
9. General Public Utilities Corporation
10. Public Advisory Committee of the Grand Canyon Visibility Transport Commission
11. Institute of Clean Air Companies
12. Interstate Natural Gas Association of America
13. Atlantic Electric Co. and Audubon Society of New Hampshire et al.
14. Maryland Department of Natural Resources and Maryland Energy Administration
15. Midwest Ozone Group
16. Missouri Department of Natural Resources
17. National Mining Association, Western Fuels Association, Inc. and the Center for Energy and Economic Efficiency
18. The Navajo Nation
19. Maine, Massachusetts, Vermont and New Hampshire Public Service Commissions
20. New Jersey Board of Public Utilities and the New Jersey Department of Environmental Protection
21. New York State Department of Public Service and the New York State Department of Environmental Conservation
22. Office of the Ohio Consumers' Counsel
23. Ohio Electric Utility Institute Environmental Committee
24. Ozone Transport Assessment Group
25. Ozone Transport Commission
26. Utility Air Regulatory Group (Edison Electric Institute, the National Rural Electric Cooperative Association and the American Public Power Association)
27. Wisconsin Department of Natural Resources

Other (Including Technical Conference Commenters)

1. Electric Power Research Institute
2. Electric Policy Technical Issues Group
3. Tejas Power Corporation
4. Competitive Power Coalition of New England
5. Mid-Continent Area Power Pool
6. Michigan Electric Coordinated Systems
7. Independent Energy Producers Association
8. Praxair, Inc.
9. Utility-Trade Corp.
10. Competitive Power Coalition of New England
11. Wyoming Public Service Commission
12. State of New Jersey
13. Paul Joskow
14. New England Conference of Public Utility Commissioners
15. Commonwealth of Massachusetts
16. Florida Electric Power Coordinating Group
17. Dine Power Authority
18. State of Connecticut Department of Environmental Protection
19. Commonwealth of Massachusetts Department of Environmental Protection
20. State of Maine Department of Environmental Protection
21. Comision Federal de Electricidad of Mexico

Appendix C—Allegations of Public Utilities Exercising Transmission Dominance

I. Examples From Proceedings Before Administrative Law Judges

These are examples of allegations that various public utilities have refused to provide comparable service, either through refusals to wheel, dilatory tactics that so protracted negotiations as to effectively deny wheeling, refusals to provide service priority equal to native load, or refusals to provide service flexibility equivalent to the utility's own use.

A. American Electric Power Service Corp. (AEP)

In 1993, AEP filed, on behalf of its public utility associate companies, an open access tariff that offered only firm point-to-point service with very limited flexibility. It did not offer network service, flexible point-to-point service, or non-firm service. Thus, it did not provide customers with the same flexibility that AEP itself has. Nor did it provide a service priority equivalent to that enjoyed by native load. The Commission set AEP's tariff for hearing and, on rehearing, held that in order not to be unduly discriminatory, the tariff had to offer comparable service. American Electric Power Service Corp., 64 FERC ¶ 61,279 (1993), *reh'g*, 67 FERC ¶ 61,168 (1994).

At hearing, Raj Rao of Indiana Michigan Power Agency (IMPA) (Ex. IMPA–1, Feb 23, 1994) and Kenneth Hegemann of American Municipal Power-Ohio, Inc. (AMP-Ohio) (Ex. AMPO–1, Feb 23, 1994), both senior management officials, testified concerning AEP's alleged discriminatory practices.[1] AMP-Ohio is an association of municipalities in Ohio, some of whose members depend on AEP for transmission and partial requirements service. IMPA is an association of municipalities in Indiana, and many of IMPA's loads are captive to the AEP transmission system. The witnesses alleged as follows:

1. In anticipation of high peak demands, AEP would contract for large blocks of available short-term power, withhold sale of short-term power, refuse to transmit third party short-term power, and require purchases from AEP at the emergency rate (100 mill/kwh) when an emergency might not exist. Ex. AMPO–1 at 6.

2. In December 1989, AMP-Ohio negotiated a 20 MW purchase of short-term power from Louisville Gas & Electric Company (LG&E). AEP refused to wheel because LG&E had earlier that day told AEP it had no power to sell to AEP. AEP then bought the power from LG&E and offered to resell it to AMP-Ohio. Ex. AMPO–1 at 6–7.

3. In January 1990, AMP-Ohio solicited bids for February power purchases from a number of utilities including AEP. AEP was not the winning bid. AMP-Ohio made arrangements to purchase the power from four winning bidders and sought transmission through AEP. When AMP-Ohio gave AEP the schedule for delivery, AEP refused to transmit the power, matched the average price of the winning bids, and made the sale itself. Ex. AMPO–1 at 7.

4. In August 1993, an AMP-Ohio member (Columbus, Ohio) was purchasing 10 MW of hourly non-displacement power from AEP and, after AEP raised its price to 60 mills/kwh, sought another source for the next hour. Consumers Power Company and Detroit Edison Company both offered non-displacement power at 40 mills. AEP refused to transmit, saying it had a 600 MW unit out and could not resell power from another source.[2] Columbus cancelled the transaction and had to buy 10 MW of power from AEP at 100 mills/kwh. Ex. AMPO–1 at 7–8.

5. In July 1993, two AMP-Ohio members (Columbus and St. Mary's) had been buying hourly non-displacement power from AEP when the price rose to 35 mills. Dayton Power & Light Company (DP&L) offered to sell at 23 mills and AEP agreed to transmit for one hour. But for the next hour, AEP said it had problems with its system, refused to transmit the power, kept the power from DP&L for itself and offered to sell power to AMP-Ohio for Columbus and St. Mary's at 100 mills. Columbus increased its local generation, but St. Mary's purchased 8 MW at 100 mills. For the next hour, AMP-Ohio arranged with DP&L for another 8 MW, hoping AEP would transmit under the 24 hour buy-sell agreement. AEP did transmit this power. Seven hours later in the day, St. Mary's Greenup Hydro project power was available and the 8 MW from DP&L was no longer needed. If St. Mary's had been receiving the hourly power that AEP had refused to transmit, St. Mary's could have switched to Greenup power. But because AMP-Ohio had changed to daily service, St. Mary's had to pay a demand charge for the entire day, even though it used the power only 7 hours and would have paid less under the hourly rate. Ex. AMPO–1 at 8–9.

6. In January 1994, AMP-Ohio sought to transfer power from one member with generation to other members, which required transmission over AEP and Toledo Edison lines. Toledo Edison said yes, AEP said no. AMP-Ohio's northern members purchased emergency power from Toledo Edison. AMP-Ohio then reminded AEP that it had agreed not to deny transmission and AEP agreed to transmit. Ex. AMPO–1 at 9.

7. IMPA arranged to buy 80 MW of short-term power from LG&E and have it wheeled, using buy-sell arrangements, through Public Service Company of Indiana (PSI) and AEP to serve IMPA's load at Richmond (an IMPA member). The delivered price was $.292 per kW-day plus a 1 mill adder. At the same time AEP arranged to buy 300 MW from PSI at $.30 per kW day plus out-of-pocket energy costs. Hence, PSI was shipping a total of 380 MW to AEP with 80 MW of that amount to be delivered to IMPA's load at Richmond. Then, on a day when IMPA should have received the 80 MW, AEP told IMPA that PSI had sold everything to AEP and that IMPA would have to buy from AEP at $.63 per kW day plus the cost of energy from AEP. IMPA purchased from AEP under protest. AEP used its control over transmission to intercept the 80 MW at a lower price and resell it as short-term power to IMPA. AEP claimed that PSI had terminated its sales to AEP on that day. But the 80 MW was independent of PSI's other sales to AEP and would not have been interrupted if AEP had not interrupted it. IMPA–1 at 7.

8. IMPA has combustion turbines owned by and located at one member, which IMPA would like to connect to the Joint Transmission System owned by IMPA, CINergy and Wabash Valley Power Association. To do so, IMPA needed a metering agreement with AEP, to which AEP would not agree. IMPA–1 at 6.

9. In January 1994, IMPA had power to sell from its turbines when AEP and others needed power. IMPA offered power to AEP but AEP it said could not purchase the power without an existing contract. Moreover, since there was no short-term tariff, IMPA could not sell the power to another utility. IMPA–1 at 6.

10. Another example of the utility engaging in dilatory tactics that raised the customer's transaction costs and effectively denied transmission is the ''sham transaction'' provision proposed by AEP. As filed, AEP's tariffs permitted it to deny service merely because a portion of the transmitted power might be used to serve a former retail customer of AEP. *See, e.g.*, Ex. BR&WVP–1 (J. Bertram Solomon testimony, February 23, 1994). (As part of a settlement AEP filed the *pro forma* tariff and withdrew this provision.)

11. Finally, AEP's originally filed tariff contained a ''prodigal customer'' provision. Under this provision, transmission customers who sought to convert back to requirements service had to give AEP five years' notice, in which case AEP and the customer would enter into negotiations to determine whether AEP will provide service at all and if so under what rate, terms, and conditions. Ex. S–39 at 1 (Staff testimony). AEP did not require notice from all new customers, only from prodigal customers. *Id.* at 2. That a potential customer was previously served by AEP is not a reason to treat the customer differently. (AEP withdrew this provision when it filed the *pro forma* tariff.)

B. Entergy Services, Inc. (Entergy)

Entergy filed a partial settlement largely adopting the NOPR *pro forma* tariffs except for two provisions (headroom and ancillary services). Because the settlement predated the filing date for customer testimony before the ALJ, the customers did not address the need for Entergy to file a tariff. However, customers did make allegations of discriminatory practices, as follows.

1. Customers alleged that Entergy flat-out refused to wheel. Louisiana Energy and Power Authority (LEPA) witness Sylvan J. Richard testified that LEPA's predecessor systems could not obtain interconnections from Entergy. Ex. SJR–1 at 50.

2. Customers also alleged that Entergy refused to provide service priority equal to native load and refused to provide service flexibility equivalent to the utility's own use. For example, LEPA witness Richard testified that even after state commissions ordered interconnections and other coordination

[1] After the Rehearing Order expanding the scope of the proceeding, AMP-Ohio and IMPA withdrew this testimony as no longer necessary. This withdrawal does not change the fact that the testimony was sworn to under oath.

[2] AEP generally limited its offer of short-term transmission to buy/sell transactions; that is, AEP would buy the power from the seller and resell it to the purchaser. Supplemental testimony of AEP Witness Baker (Ex. A–73) at 27–29. Often, the terms of the buy/sell transaction required transmission dependent utilities (TDUs) to maintain reserves and meet contractual commitments for at least a year. *Id.*

services, LEPA's predecessors were still not able to obtain coordination services because Entergy was not willing to coordinate and because the transmission service it did offer was inflexible, unidirectional point-to-point service, which prevented economic coordination with others. *Id.* at 50–51.

3. South Mississippi Electric Power Association (SMEPA) witness J. Bertram Solomon testified that Entergy's original "open access" tariff was restricted to point-to-point service, proposed separate charges for each operating company, and required the cancellation of existing agreements in order to take service under the proposed tariff. Ex. SMEPA–10 at 28. Entergy eventually filed a network tariff, but proposed different local facilities charges for the various Entergy public utility operating subsidiaries. *Id.* at 29. Since these local facilities charges were higher than the transmission component of the subsidiaries' bundled rates, Entergy obtained a competitive advantage. *Id.*

4. The Arkansas Cities and Cooperatives (ACC) is a group of cities and cooperatives that own or operate electric generation or distribution systems in Arkansas. ACC Witness Steven Merchant testified that Entergy has segregated the wholesale market between two of its subsidiaries, Arkansas Power & Light Copmpany (APL) and Entergy Power, Inc. (EPI). Ex. SMM–1 at 16. In marketing power and energy in Arkansas, EPI is subject to an Arkansas Commission order that bars EPI from competing with APL for wholesale loads without first obtaining a waiver. *Id.* Recently, EPI requested this waiver for all wholesale transactions in Arkansas except for wholesale customers currently served by an Entergy subsidiary; in other words, EPI requested the Arkansas Commission to expand competition for all wholesale customers except where EPI might compete with APL. *Id.* ACC witness Merchant concluded that, since EPI does not compete with APL, Entergy insulates APL's wholesale business from competition and denies those wholesale customers access to EPI as a source of power, thereby limiting alternative generation sources available to ACC. *Id.* at 17–19. (Entergy's witness Kenney stated that Entergy has recently filed a joint motion with ACC to the Arkansas Commission seeking to extend the waiver and permit EPI to sell to APL's wholesale customers. Ex. JFK–11 at 14–15.)

C. Pacific Gas & Electric Company (PG&E)

Northern California Power Agency (NCPA) attached several documents to its 1988 complaint in Docket No. EL89–4. These documents were provided to support NCPA's claim that PG&E's unreasonable practices under the PG&E/NCPA Interconnection Agreement (IA) effectively denied NCPA access to transmission properly requested under the IA. Although the parties eventually settled and the Commission terminated the docket with a letter order dated May 18, 1988, these documents provide allegations of PG&E using dilatory tactics that so protracted negotiations as to effectively equal a refusal to wheel.[3]

1. PG&E stated that since transmission was not currently available, it was entitled to wait 72 months before providing transmission; that is, transmission access could not be granted before the passing of the 72-month notice period. NCPA 1988 Complaint, Ex. 3. However, the IA provided that transmission be provided when it becomes actually available. PG&E also requested substantial additional information, which NCPA considered beyond that reasonably necessary for a study, but still provided. PG&E then determined that transmission was not available, reasoning that transmission was unavailable unless all the transmission requested could be provided 8760 hours per year without restrictions or limitations, extending through the expiration of the agreement in 2013. NCPA 1988 Complaint at 9.

2. On November 27, 1987, NCPA made a new transmission request to PG&E, seeking 50 MW of bi-directional transmission at Midway. NCPA 1988 Complaint, Ex. 5. On January 28, 1988, PG&E filed an interconnection agreement with Turlock Irrigation District (TID) that provided TID with 50 MW of bi-directional transmission at Midway. *Pacific Gas & Electric Company,* 42 FERC ¶ 61,406, *order on reh'g,* 43 FERC ¶ 61,403 (1988). On February 22, 1988, PG&E advised NCPA that all firm transmission service available at Midway had been fully subscribed. NCPA 1988 Complaint, Ex. 6. Then, on March 29, 1988, PG&E filed with the Commission an interconnection agreement with Modesto Irrigation District (MID), that provided MID with 50 MW of bi-directional transmission at Midway. *Pacific Gas & Electric Company,* 44 FERC ¶ 61,010 (1988). At about the same time (in the last week in March 1988), PG&E advised NCPA that the allocations of transmission to TID, MID, and others, including a not yet finalized allocation to Sacramento Municipality Utility District, had used all the transmission available at Midway. NCPA 1988 Complaint, Exs. 7 and 8.

D. Northeast Utilities Service Company (NU)

This is the case where Northeast Utilities acquired Public Service of New Hampshire (PSNH) (Docket No. EC90–10). New England Power Company (NEP) witness Robert Bigelow's direct testimony expressed concern over the "relatively restrictive transmission policies of both" NU, on behalf of Northeast Utilities' public utility subsidiaries, and PSNH. Bigelow Direct Testimony at 21 (filed May 25, 1990). In his cross rebuttal testimony, Mr. Bigelow testified that "NU has a poor track record as a provider of transmission service" and "PSNH also has an abhorrent track record as a provider of transmission services." Bigelow Cross Rebuttal Testimony, at 3 (filed June 20, 1990). Mr. Bigelow described both NU's and NEP's (his own company) failure to provide service flexibility equivalent to their own use. Except for NEP's TDUs, both NEP and NU historically provided only point-to-point transmission, which required separate scheduling for each transaction. Bigelow Cross Rebuttal at 4.

E. Southern California Edison Company and San Diego Gas and Electric Company

The evidence in this merger proceeding (Docket No. EC89–5) included testimony from a number of witnesses describing instances of Edison's conduct. Richard Greenwalt was the power supply supervisor for the City of Riverside, California. He was responsible for scheduling all purchases of energy for Riverside and for the cities of Azusa, Banning and Colton, California. Greenwalt testimony at 1 (November 1989). (These four cities and Anaheim, California, are collectively referred to as the Southern Cities or Cities.) Joseph Hsu was the Director of Utilities for Azusa. Hsu testimony at 1 (November 1989). Gale Drews was the electric utility director of Colton. Drews testimony at 1–2 (November 1989). Bill Carnahan was the director for Riverside. Carnahan testimony at 1 (November 1989). Gordon Hoyt was the general manager of the Anaheim power department. Hoyt testimony at 1 (November 1989). Dan McCann was the power coordination supervisor for Anaheim. He supervised Anaheim's load scheduling and is a former Edison employee, having worked for Edison for 20 years. McCann Testimony at 1–2 (November 1989). These witnesses testified that Edison refused to wheel as follows.

1. Edison's policy was to curtail the Cities any time it could be justified using any of a list of acceptable reasons to deny interruptible transmission service. *Id.* at 22–23.

2. Edison would not generally provide transmission service when Edison could save money by itself purchasing the economy energy that would be wheeled. McCann testimony at 19. The Cities called Edison every hour to request interruptible transmission service. *Id.* Edison often refused to sell energy available in the Western Systems Power Pool to the Cities and then made available higher cost contract energy or partial requirements service. *Id.* at 19–20.

3. When Anaheim requested Edison provide firm transmission of power from neighboring states, Edison would often agree to provide non-firm service but would not integrate the capacity for many years in the future, saying that its control area did not need capacity at that time. Hoyt testimony at 9. Since the selling utility was interested in a sale of capacity, not just energy, the transaction would not occur. *Id.* Edison repeatedly used its control over transmission to deny Anaheim access to low-cost firm power. *Id.* at 9–10.

4. While Edison provided short-term firm transmission service to the Cities, it would only provide long-term firm service for three specific resources: The SONGS nuclear plant, a specific IPP, and Hoover Dam power. Hoyt testimony at 20. One of Edison's reasons for denying long-term transmission was that Edison desired to reserve the transmission for its own future (unspecified) needs. *Id.*

5. In the 1970s, Edison refused to allow the Cities access to the Pacific Intertie. Hoyt testimony at 21; Drews testimony at 7–8.

[3] All of these incidents are related to and examples of PG&E's conduct described in the NOPR (FERC Stats. & Regs. ¶ 32,514 at 33,073 n.151), that is, the history of PG&E's attempt to avoid its commitments made to the California owners of the California Oregon Transmission Project (COTP). However, these incidents are not exactly the same as the incidents described in the NOPR, because NCPA is not one of the owners of the COTP.

6. In 1988, Edison refused to provide transmission service for a Cities power purchase from Public Service Company of New Mexico (PSNM) from Palo Verde Nuclear station. Hoyt testimony at 21.

7. Edison has refused to provide requested firm transmission from

—California-Oregon border to Midway Station
—Nevada-Oregon Border to Sylmar Substation
—Palo Verde Switchyard to Vista
—SONGS Switchyard to Vista.

Carahan testimony at 15.

8. Riverside requested transmission from Palo Verde and was told that such service was not available. Carnahan testimony at 16. Edison offered Riverside only 12 MW of curtailable transmission entitlement to provide Riverside's share of Palo Verde. *Id.* This service was neither large enough or long enough, and Edison insisted on unreasonable terms and conditions. *Id.*

9. Azusa, Banning and Colton had a contract with Edison that entitled them to use their Palo Verde firm transmission path to schedule energy to meet their contract energy obligation. Edison refused to permit the three cities to use that path. Edison did not contest that the contracts allowed this use, but said that the scheduling of such small amounts of energy for the three cities would be too burdensome. Greenwalt testimony at 14.

10. Edison would not respond in a timely manner to the Cities' requests, routinely taking months to respond. Drews testimony at 15.

11. During the 1980s, Edison provided Colton with some transmission service to allow the Cities to reach certain suppliers, but limited the choices available to the Cities and imposed terms and conditions that increased the Cities' costs and placed Colton at a disadvantage against Edison. Drews testimony at 9. Arranging alternative generation sources was difficult because the Cities always had to first get Edison to state whether it would provide transmission.

12. During 1988 and 1989, a dispute arose between Edison and the Cities concerning the Hoover Uprating Project. Drews testimony at 16. Edison argued that for the months when units were out of service for uprating, and Southern Cities capacity was reduced to zero, Southern Cities would not receive an energy credit, even though energy was still available and used by Edison. But the contracts allowed a participant who did not have capacity to still schedule its energy as non-firm energy on the capacity of another participant. *Id.* at 16–17.

13. In 1986, Azusa negotiated a power purchase contract with the California Department of Water Resources in increments of first 5 MW and then 2 MW (for a total of 7 MW). Hsu testimony at 14. First Edison assured Azusa that the transmission for the additional 2 MW would not be a problem. *Id.* Then Edison would not agree to amend the transmission service agreement for the additional 2 MW. *Id.*

14. In 1986, Azusa notified Edison of Special Condition 12[4] purchases from PG&E and requested firm transmission service. *Id.* Two months before service was to begin, Edison notified the Cities of a problem with the transmission lines. *Id.* Transmission was eventually granted, but only after a four-month delay and substantial losses to the Cities. *Id.* Then Edison decided there was no problem with its transmission facilities. *Id.* at 14–15.

15. In 1986–87, the Cities purchased 20 MW from PG&E and 80 MW from Deseret G&T Cooperative. Hoyt testimony at 7–8. Edison stated that without reinforcement of its transmission system, Edison would not provide the transmission. *Id.* There was a five-month delay during which the Cities were forced to purchase from Edison at a higher cost. *Id.* at 8–9. Then Edison decided that the transmission system did not need reinforcement. *Id.* at 8.

16. Edison also refused to provide a service priority equal to that of native load. It would curtail the Cities in order to purchase more economy energy for itself. McCann testimony at 28. If Edison could make the purchase, it would curtail the City and use the energy for itself. *Id.* When Edison curtailed the Cities, they were not able to purchase economy energy and instead purchased energy from Edison. *Id.* at 24.

17. According to Edison, the interruptible transmission it provided the Cities was interruptible for any reason. *Id.* at 20. A purchase could be terminated the hour after it is begun or even during the hour. *Id.* As a result, the Cities lost opportunities to make advantageous economy purchases. *Id.* at 20–21.

18. Edison also refused to provide customers flexibility similar to the flexibility Edison provided itself. Edison's refusal to provide bi-directional transmission service restricted the Cities' abilities to purchase hydroelectric energy from the Pacific Northwest. Hoyt testimony at 22. Because most contracts with Northwest utilities require a return of power, the Northwest utilities would not deal with the Cities without transmission to return energy. *Id.* at 22–23. Edison did provide bi-directional transmission to the Los Angeles Department of Water & Power (LADWP) to accommodate flows to and from Arizona. *Id.*

19. Riverside was unable to obtain non-firm service more than two hours in advance of need. Carnahan testimony at 18.

20. Riverside and Colton were both served out of Edison's Vista substation. Although the two cities were on the same 69 kV bus, Edison would not allow them to sell energy to each other. Greenwalt testimony at 17.

21. Riverside's agreement with Edison allowed Riverside to purchase a block of energy through the WSPP and divide it up among the four Cities (Azusa, Banning, Colton and Riverside). Greenwalt testimony at 17. When Riverside had excess energy from other sources, Edison would not permit it to sell that energy to the other three cities. *Id.* For example, Riverside attempted to sell Deseret energy transmitted by LADWP to the Edison system. *Id.* at 17–18. LADWP would not break out the Cities' shares of that energy, and Edison would not accept the energy as a delivery for all four cities. *Id.* at 18. Edison argued that because this energy was excess energy that Riverside could not use, Riverside did not have transmission rights to bring it into the control area. *Id.* As a result, Riverside paid for the energy delivered by LADWP to the Edison control area, but could not sell it to the other three cities, and gave it to Edison itself, which consumed the energy without making any payment for it. *Id.* Riverside tried a number of alternative paths, including using WSPP transmission where Riverside paid Edison 5 mills to connect to Azusa, 5 mills to connect to Banning, and 5 mills to connect to Colton for each megawatthour. While this approach was successful for a while, eventually Edison refused to permit these sales.

22. Edison claimed that the Cities only have transmission rights to bring in enough Special Condition 12 energy to satisfy the Cities' load. Greenwalt testimony at 18.

23. Edison contended that the Cities' load requirements were satisfied first by integrated resources and then by Special Condition 12 and economy energy purchases. *Id.* at 19. When the Cities' integrated resources exceeded their load, any Special Condition 12 resources became excess. Under Riverside's Deseret contract, the Cities were required to take a minimum of 35 MW each hour. *Id.* Edison acknowledged that it was obligated to buy, or allow the Cities to sell, any excess energy from Riverside's integrated resources. *Id.* However, Edison refused to give the Cities credit for excess Special Condition 12 energy brought into the area, claiming that the Cities could not have brought it in because they did not have transmission rights. *Id.*

II. Other Examples of Transmission Disputes

Disputes over transmission are not uncommon, contrary to EEI's suggestion. Some recent examples taken from pleadings and other documents and from Commission orders reveal that it has been very difficult for various entities in the electric power industry to agree on transmission rights. These examples also reveal that even after issuance of *AEP* and the Open Access NOPR with its proposed *pro forma* tariffs, there has been considerable controversy over whether various utilities' "open access" tariffs deviate from those tariffs. (The Commission has allowed utilities that adopt tariffs that match or exceed the non-rate terms and conditions in the NOPR *pro forma* tariffs to obtain certain benefits.)

A. In a letter of February 3, 1995 to Mr. Gerald Richman of the Commission's Enforcement section in the Office of the General Counsel, Steven J. Kean, Vice President, Regulatory Affairs, Enron Power Marketing, Inc. (Enron) alleged that Niagara Mohawk Power Corporation (NiMo) refused to wheel power from Rochester Gas & Electric (RG&E) to Enron under RG&E's transmission contract with NiMo; however, when Enron revealed the buyer, NiMo did wheel power for RG&E to the buyer. Mr. Kean alleged that this was not an isolated incident. NiMo argued that the contract did not require it to

[4] Special Condition 12 of the Integrated Operations Agreement between Edison and the Southern Cities defined certain Special Condition 12 resources and allowed the Cities to make certain uses of those resources, subject to certain restrictions.

provide RG&E with transmission to Enron. It also said that the principle of comparability does not require the service. Letter of November 21, 1994 from NiMo representative A. Karen Hill to Gerald Richman.

B. The Commission's Task Force Hot Line (Hot Line) received a complaint that a member of the New York Power Pool (NYPP) refused to transmit power that another member bought from a power marketer. In a letter of November 17, 1994, from Chair Moler to Mr. William J. Balet, Executive Director of NYPP, Chair Moler explained that the Commission's enforcement staff had investigated and found the allegation to be true.

C. In *Southern Minnesota Municipal Power Agency* v. *Northern States Power Company (Minnesota)*, 73 FERC ¶ 61,350 (1995), NSP and SMMPA had a contract under which NSP agreed to provide transmission service. However, the parties had numerous disputes over the service. The Commission found that NSP had misinterpreted the contract in several ways. For, example, SMMPA argued that it should be able to directly schedule its deliveries of energy out of the NSP control area and that it should not be limited to particular points of delivery. NSP argued that only it was entitled to control the physical operation of scheduling. The Commission found that the clear language of the contracts gave SMMPA the authority to schedule its own power.

D. *Mid-Continent Area Power Pool*, 72 FERC ¶ 61,223 (1995), involved MAPP's membership criteria, which made it impossible for a power marketer to join MAPP and obtain the benefits of certain transmission services available only to MAPP members. The Commission found that the membership criteria may be unreasonable, particularly since there may be less burdensome ways of setting up membership criteria for non-traditional entities.

Appendix D—Pro Forma Open Access Transmission Tariff

Table of Contents

I. Common Service Provisions

1. Definitions

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.6 Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.8 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale; electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled Transmission Service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Transmission Provider.

1.12 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.13 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.15 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.16 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III the Tariff and calculated on a rolling twelve month basis.

1.17 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.18 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.20 Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.21 Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

1.22 Network Load: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.24 Network Operating Committee: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.25 Network Resource: Any designated generating resource owned or purchased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.26 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.27 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.28 Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations.

1.29 Part I: Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement.

1.34 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement.

1.35 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.43 System Impact Study: An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.44 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.45 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.46 Transmission Provider: The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.47 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. If the Transmission Provider offers an affiliate a rate discount, or attributes a discounted Ancillary Service rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Ancillary Service rate to all Eligible Customers. Information regarding any discounted Ancillary Service rates must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR part 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public

Utilities). In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if the provision of such Transmission Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such Transmission Service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act and shall provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving Transmission Service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority: Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis *i.e.*, in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. After the deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Firm Point-To-Point Transmission Service. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, Curtailments will be proportionally allocated among the Transmission Provider's Native Load Customers, Network Customers, and Transmission Customers taking Firm Point-To-Point Transmission Service. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *10:00 a.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour (or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider). Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to *twenty (20) minutes* (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than *2:00 p.m.* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to *twenty (20) minutes* [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

e. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit: A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1.

17.6 Execution of Service Agreement: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to *five (5) one-year extensions* for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved

Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted *no earlier than sixty (60) days* before service is to commence; requests for weekly service shall be submitted *no earlier than fourteen (14) days* before service is to commence, requests for daily service shall be submitted *no earlier than two (2) days* before service is to commence, and requests for hourly service shall be submitted *no earlier than noon the day* before service is to commence. Requests for service received *later than 2:00 p.m.* prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transmission Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service *(i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.* [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the maximum charge, based on the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the

Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications: Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities: The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service: If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G.

29.2 Application Procedures: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), which shall include, for each Network Resource:

—Unit size and amount of capacity from that unit to be designated as Network Resource
—VAR capability (both leading and lagging) of all generators
—Operating restrictions
—Any periods of restricted operations throughout the year
—Maintenance schedules
—Minimum loading level of unit
—Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons
—Approximate variable generating cost ($/MWH) for redispatch computations
—Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource
—Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(vi) Description of Eligible Customer's transmission system:

—Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
—Operating restrictions needed for reliability
—Operating guides employed by system operators
—Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
—Location of Network Resources described in subsection (v) above
—10 year projection of system expansions or upgrades
—Transmission System maps that include any proposed expansions or upgrades
—Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and

(vii) Service Commencement Date and the term of the requested Network Integration

Transmission Service. The minimum term for Network Integration Transmission Service is one year.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement: The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation owned or purchased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service pursuant to an Application under Section 29.

30.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load plus losses.

30.5 Network Customer Redispatch Obligation: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load Ratio Share.

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the Transmission Provider to serve all of its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission

Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (*e.g.* the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the maximum charge, based on the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1⁄12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the [applicable regional reliability council], (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1—Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2—Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Control Area where the Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The Transmission Provider shall establish a deviation band of +/− 1.5 percent (with a minimum of 1 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $________/KW of Reserved Capacity per year.

(2) Monthly delivery: $________/KW of Reserved Capacity per month.

(3) Weekly delivery: $________/KW of Reserved Capacity per week.

(4) Daily delivery: $________/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own

transactions, the Transmission Provider must offer at the same time the same discounted Firm Point-To-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $________/KW of Reserved Capacity per month.

(2) Weekly delivery: $________/KW of Reserved Capacity per week.

(3) Daily delivery: $________/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $________/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Non-Firm Point-To-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any non-firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Attachment A—Form Of Service Agreement for Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________________, is entered into, by and between ________________ (the Transmission Provider), and ________________ (''Transmission Customer'').

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in the amount of $________, in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on ________________.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

Transmission Customer:

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

In Witness Whereof, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ____

Name ____

Title ____

Date ____

Transmission Customer:

By: ____

Name ____

Title ____

Date ____

Specifications for Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ________________

Start Date: ________________

Termination Date: ________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. ________________

3.0 Point(s) of Receipt: ________________

Delivering Party: ________________

4.0 Point(s) of Delivery: ________________

Receiving Party: ________________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): ________________

6.0 Designation of party(ies) subject to reciprocal service obligation: ________________

7.0 Name(s) of any Intervening Systems providing transmission service: ________________

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ________________

8.2 System Impact and/or Facilities Study Charge(s): ________________

8.3 Direct Assignment Facilities Charge: ________________

8.4 Ancillary Services Charges: ________________

Attachment B—Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ____________, is entered into, by and between ____________, (the Transmission Provider), and ____________, (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

Transmission Customer:

____

7.0 The Tariff is incorporated herein and made a part hereof.

In Witness Whereof, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ____

Name ____

Title ____

Date

Transmission Customer:

By: ____

Name ____

Title ____

Date

Attachment C—Methodology To Assess Available Transmission Capability

To be filed by the Transmission Provider.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider.

Attachment E—Index Of Point-To-Point Transmission Service Customers

Customer ______________________________
Date of Service Agreement ______________

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider.

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider.

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ___________.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer ______________________________
Date of Service Agreement ______________

Appendix E—Group 1 Public Utilities

Alabama Power Company
Appalachian Power Company
Arkansas Power & Light Company
Atlantic City Electric Company
Baltimore Gas & Electric Company
Black Hills Power & Light Company
Cambridge Electric Light Company
Central Illinois Light Company
Central Power and Light Company
Central Vermont Public Service Corporation
Cheyenne Light, Fuel and Power Company
Cincinnatti Gas & Electric Company
Citizens Utilities Company
Columbus Southern Power Company
Commonwealth Edison Company
Commonwealth Electric Company
Connecticut Light & Power Company
Connecticut Valley Electric Company
Consumers Power Company
Dayton Power & Light Company
Delmarva Power & Light Company
Duke Power Company
Duquesne Light Company
Florida Power & Light Company
Florida Power Corporation
Georgia Power Company
Granite State Electric Company
Gulf Power Company
Gulf States Utilities Company
Holyoke Power & Electric Company
Holyoke Water Power Company
Idaho Power Company
IES Utilities, Inc.
Illinois Power Company
Indiana Michigan Power Company
Interstate Power Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas & Electric Company
Kentucky Power Company
Kentucky Utilities Company
Kingsport Power Company
Louisiana Power & Light Company
Louisville Gas & Electric Company
Maine Public Service Company
Massachusetts Electric Company
Metropolitan Edison Company
MidAmerican Energy Company
Midwest Energy, Inc.
Minnesota Power & Light Company
Mississippi Power Company
Mississippi Power & Light Company
Monongahela Power Company
Montana Power Company
Montaup Electric Company
Nantahala Power & Light Company
Narragansett Electric Company
Nevada Power Company
New England Power Company
New Orleans Public Service Inc.
Northern Indiana Public Service Company
Northern States Power Company(Wisconsin)
Northern States Power Company (Minnesota)
Ohio Power Company
Orange & Rockland Utilities, Inc.
Pacific Gas & Electric Company
PacifiCorp
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Pike County Light & Power Company
Portland General Electric Company
Potomac Edison Company
Potomac Electric Power Company
PSI Energy, Inc.
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of New Hampshire
Public Service Electric and Gas Company
Public Utility Company of Oklahoma
Puget Sound Power & Light Company
Rockland Electric Company
San Diego Gas & Electric Company
Savannah Electric and Power Company
South Carolina Electric & Gas Company
Southern California Edison Company
Southern Indiana Gas & Electric Company
Southwestern Electric Power Company
Southwestern Public Service Company
Tampa Electric Company
United Illiminating Company
UtiliCorp United, Inc.
Washington Water Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Company
Western Resources, Inc.
Wheeling Power Company
Wisconsin Electric Power Company
Wisconsin Power & Light Company
Wisconsin Public Service Corporation

Note: Transmission tariffs have also been filed for some public utilities associated with pending merger applications. These individual utilities are not included in Group 1 and will be required to file tariffs on compliance with the Final Rule. They are: Centerior's filing for Cleveland Electric Illuminating Company and Toledo Edison Company; Interstate Energy Corporation's filing for South Beloit Water, Gas & Electric Company; Resources West's for Sierra Pacific Power Company; and the rate filing associated with the merger of Union Electric Company and Central Illinois Public Service Company.

Appendix F—Group 2 Public Utilities

Arizona Public Service Company
Bangor Hydro-Electric Company
Blackstone Valley Electric Company
Boston Edison Company
Carolina Power & Light Company
Central Hudson Gas & Electric Corporation
Central Illinois Public Service Company
Central Louisiana Electric Company, Inc.
Central Maine Power Company
Cleveland Electric Illuminating Company
Commonwealth Edison Company of Indiana
Concord Electric Company
Consolidated Edison Company of New York Inc.
Consolidated Water Power Company
Detroit Edison Company
Eastern Edison Company
Edison Sault Electric Company
El Paso Electric Company
Electric Energy Inc.
Empire District Electric Company
Exeter & Hampton Electric Company
Fitchburg Gas & Electric Light Company
Green Mountain Power Corporation
Indiana-Kentucky Electric Corporation
Indianapolis Power & Light Company
Kanawha Valley Power Company
Lockhart Power Company
Long Island Lighting Company
Long Sault, Inc.
Madison Gas & Electric Company
MDU Resources Group, Inc.
Mt. Carmel Public Utility Company
New England Electric Transmission Corporation
New England Hydro Transmission Electric Company
New England Hydro Transmission Corporation
New York State Electric & Gas Corporation
Newport Electric Corporation
Niagara Mohawk Power Corporation
Northwestern Public Service Company
Northwestern Wisconsin Electric Company
Ohio Edison Company
Ohio Valley Electic Corporation
Oklahoma Gas & Electric Company
Old Dominion Electric Cooperative
Otter Tail Power Company
Pennsylvania Power Company
Peoples Electric Cooperative
Rayburn Country Electric Cooperative
Rochester Gas & Electric Corporation
Sierra Pacific Power Company
South Beloit Water, Gas & Electric Company
St. Joseph Light & Power Company
Superior Water, Light and Power Company
Texas-New Mexico Power Company
Toledo Edison Company
Tucson Electric Power Company
UGI Utilities, Inc.
Union Electric Company
Union Light, Heat & Power Company
Unitil Power Corporation
Upper Penninsula Power Company
Vermont Electric Transmission Company
Vermont Electric Power Company
Virginia Electric & Power Company
Yadkin, Inc.

Appendix G

I. Legal Analysis of Commission Jurisdiction Over the Rates, Terms and Conditions of Unbundled Retail Transmission in Interstate Commerce

Based on an analysis of the relevant legislative history and case law under the Federal Power Act (FPA), the Commission concludes that it has exclusive jurisdiction over the rates, terms and conditions of the unbundled transmission in interstate commerce, by a public utility, of electric energy to an end user. This is also known as retail wheeling in interstate commerce. [1]

The Commission's jurisdiction over the rates, terms and conditions of transmission in interstate commerce derives from Congress' power to regulate interstate commerce under the United States Constitution [2] and the FPA. When Congress enacted the FPA, it gave the Commission exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities. The Supremacy Clause of the Constitution provides that federal laws enacted pursuant to the powers delegated to the federal government by the United States Constitution are the supreme law of the land.[3] Accordingly, to the extent that retail wheeling involves transmission in interstate commerce by public utilities, the rates, terms and conditions of such service are subject to the exclusive jurisdiction of the Commission, and must be filed with the Commission.[4]

1. Relevant Federal Power Act Provisions

Section 201(b)(1) of the FPA provides:

The provisions of this Part shall apply to *the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce* * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

16 U.S.C. 824(b)(1) (emphasis added). Thus, the statute on its face limits Commission jurisdiction over sales of energy to sales at wholesale, but does not limit jurisdiction over transmission to transmission used only for wholesale sales.

Sections 201 (c) and (d) define the meaning of ''the transmission of electric energy in interstate commerce'' and ''sale of electric energy at wholesale in interstate commerce.'' Section 201(c) provides:

For the purpose of this Part, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof: but only insofar as such transmission takes place within the United States.

16 U.S.C. 824(c). Section 201(d) provides:

The term ''sale of electric energy at wholesale'' when used in this Part means a sale of electric energy to any person for resale.

16 U.S.C. 824(d).

Sections 205 and 206 of the FPA give the Commission jurisdiction over the rates, terms and conditions of transmission in interstate commerce, and sales at wholesale in interstate commerce, by public utilities. 16 U.S.C. 824d and 824e.

2. Legislative History and Case Law

Much of the legislative history of the FPA indicates that Congress intended the Commission's jurisdiction to extend only to those matters which the *Attleboro* decision [5] held to be beyond the reach of the States. For instance, the report accompanying the Senate bill states that subsection (b) ''leaves to the States the authority to fix local rates even in cases where the energy is brought in from another State.'' [6] In other words, states retain authority to regulate rates of electric energy to ultimate consumers. The Senate report also states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in (*Attleboro*) to be beyond the reach of the States. *Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines* and over the generating facilities which produce energy [7] for interstate transmission and sale.

S. Rep. No. 621, 74th Cong., 1st Sess. 48 (1935) (emphasis added). Thus, federal jurisdiction over transmission lines is not dependent on whether those lines are used to effect a sale, wholesale or otherwise.

The provisions of FPA section 201 reserving certain regulatory authority to the States have been interpreted narrowly.[8] The Supreme Court has stated:

In section 201(b), Congress did no more than leave standing whatever valid state laws then existed relating to the exportation of hydroelectric energy; by its plain terms, section 201(b) simply saves from pre-emption under Part II of the Federal Power Act such state authority as was otherwise ''lawful.'' [9]

The Court also stated:

Nothing in the legislative history or language of the statute evinces a congressional intent 'to alter the limits of state power otherwise imposed by the Commerce Clause,' * * * or to modify the earlier holding of this Court concerning the limits of state authority to restrain interstate trade.[10]

Unlike the narrow interpretations given to the FPA provisions reserving certain regulatory authority to the States,[11] the courts have construed transmission ''in interstate commerce'' broadly. The term does not turn on whether the contract path for a particular power or transmission sale crosses state lines, but rather follows the physical flow of electricity. Because of the highly integrated nature of the electric system, this results in most transmission of electric energy being ''in interstate commerce.''

One of the earliest cases construing Commission jurisdiction over transmission was *Jersey Central Power & Light Co.* v. *FPC,* 319 U.S. 61 (1943) (*Jersey Central*). In that case, the Commission asserted jurisdiction over a New Jersey utility by showing that the utility owned transmission facilities that were used to transmit energy in interstate commerce. The Court found that the Commission had demonstrated that the utility owned transmission facilities that were indirectly interconnected, through a second New Jersey utility, to facilities owned by a New York utility and that the facilities were used to transmit electric energy in interstate commerce.

The Court noted that section 201(c) of the FPA defines electric energy transmitted in interstate commerce to be energy ''transmitted from a State and consumed at any point outside thereof.'' The Court stated:

It is impossible for us to conclude that this definition [of transmission in interstate commerce] means less than it says and applies only to the energy at the instant it crosses the state line and so only to the facilities which cross the line and only to the company which owns the facilities that cross the line.

319 U.S. at 71. Thus, a critical question regarding the jurisdictional status of a wheeling transaction is whether the facilities used to provide the service transmit electric energy in interstate commerce.

[1] Section 212(h) of the FPA provides that no order issued under the FPA shall be conditioned upon or require the transmission of electric energy directly to an ultimate consumer. 16 U.S.C. 824k(h). The Commission's assertion of jurisdiction in this final rule is over the rates, terms and conditions of retail transmission that occurs voluntarily or as a result of a state retail access program.

[2] U.S. Const. art I, Section 8, cl.3.

[3] U.S. Const. art. VI, cl.2.

[4] *See* Montana-Dakota Utilities Co. v. Northwestern Public Service Co., 341 U.S. 246, 251–52 (1951) (*Montana-Dakota*).

[5] Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927) (*Attleboro*). In *Attleboro,* the Supreme Court held that State regulation of the interstate sale of electricity was barred by the Commerce Clause because such regulation would impose a ''direct burden'' on interstate commerce.

[6] S. Rep. No. 621, 74th Cong., 1st Sess. 48 (1935). *See also* H.R. Rep. No. 1318, 74th Cong., 1st Sess. 8 (1935).

[7] The provisions of the Senate bill regarding federal jurisdiction over generating facilities were eliminated from the final version of the bill.

[8] Section 201(a) declares that Federal regulation of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, ''such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.'' 16 U.S.C. 824(a). Section 201(b)(1) states that the provisions of Part II of the FPA apply to the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce but, except as specifically provided, ''shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line.'' 16 U.S.C. 824(b)(1).

[9] New England Power Co. v. New Hampshire, 455 U.S. 331, 341 (1982) (*NEPCO*).

[10] *Id.* (citation omitted).

[11] While Congress may exercise its Commerce Clause authority to grant the States that ''ability to restrict the flow of interstate commerce that they would not otherwise enjoy,'' Lewis v. BT Investment Managers, Inc., 447 U.S. 27, 44 (1980), States may not exercise such regulatory powers unless Congress has expressly stated its intention to make such an affirmative grant of power. *NEPCO,* 455 U.S. at 343.

In *Connecticut Light & Power Co.* v. *FPC*, 324 U.S. 515 (1945) (*CL&P*), the Court reviewed the Commission's finding that a Connecticut utility was jurisdictional because it owned transmission facilities that were used in interstate commerce. The Court generally embraced the *Jersey Central* standard for determining whether facilities are used to transmit electric energy in interstate commerce. The Court emphasized that whether certain facilities transmit electric energy in interstate commerce is more a technical than a legal question. The Court stated:

Federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.

324 U.S. at 529. Thus, the Court adopted the *Jersey Central* test providing that the Commission's jurisdiction generally extends to transmission facilities that transmit electric energy in interstate commerce.

The Court also applied the *Jersey Central* test in *FPC* v. *Florida Power & Light Co.*, 404 U.S. 453 (1972), affirming the Commission's finding of jurisdiction over a Florida utility. The Commission demonstrated that the utility transmitted power to another Florida utility's ''bus''[12] and that power was simultaneously transferred from the ''bus'' to a Georgia utility. The Court upheld the Commission's finding that electric energy from the two Florida utilities was commingled and was therefore transmitted in interstate commerce. 404 U.S. at 463.

In all of the above cases, the Court's decisions turned on whether energy being transmitted flowed in interstate commerce as a technical matter. The decisions did not turn on whether the transmission of energy flowing in interstate commerce involved energy that was being sold for resale or was being sold to an end user. Thus, there is nothing in the statute, its legislative history, or the case law to indicate that the Commission's jurisdiction over rates, terms and conditions of transmission in interstate commerce extends only to wholesale transmission and not retail transmission. Indeed, the statute on its face gives the Commission jurisdiction over transmission in interstate commerce and makes no distinction between wholesale transmission and retail transmission.

However, there are two important limitations on Commission authority. First, as discussed above, the FPA does not give the Commission jurisdiction over sales of electric energy at retail. Such sales historically have been bundled sales (*i.e.*, generation and transmission), and courts and the Commission have recognized State jurisdiction over bundled sales of energy. Second, under section 201(b)(1) of the FPA, the Commission does not have jurisdiction over facilities used in local distribution. In *CL&P*, the Court stated that local distribution facilities are exempt from Commission jurisdiction even if those facilities ''carry no energy except extra-state energy.'' 324 U.S. at 531.

In the next section the Commission further discusses the statutory provisions and case law that shed light on the demarcation between transmission and local distribution, and thus on the jurisdictional line between federal and State authority.

II. Legal Analysis of Commission Jurisdictional Transmission Facilities and State Jurisdictional Local Distribution Facilities

Two specific circumstances are addressed: First, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

Second, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to an end user?

Based on an analysis of the relevant legislative history and case law under the FPA, the Commission reaches the following conclusions. With respect to the first circumstance, the Commission concludes that a public utility's facilities used to deliver electric energy to a wholesale purchaser, whether labeled ''transmission,'' ''distribution,'' or ''local distribution'' are subject to the Commission's exclusive jurisdiction under sections 205 and 206 of the FPA, and that a public utility's facilities used to deliver electric energy from the wholesale purchaser to the ultimate consumer are ''local distribution'' facilities subject to the rate jurisdiction of the state. [13]

With respect to the second circumstance, the Commission believes that, based on the particular facts of the case, some of the public utility's facilities used to deliver electric energy to an end-user may be FERC-jurisdictional transmission facilities, while some of the facilities used may be state-jurisdictional local distribution facilities.

We set forth below the relevant legislative history and case law, our legal conclusions, and the factors which we believe are indicative of whether facilities are used in ''local distribution'' or ''transmission in interstate commerce,'' as those terms are used in the FPA.

1. Relevant Federal Power Act Provisions

The Commission's jurisdiction is set forth in section 201 of the FPA. [14] Section 201(b)(1) provides in pertinent part:

The provisions of this Part shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over *facilities used in local distribution* or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[15]

Some of the court decisions that construe jurisdictional facilities under section 201 also construe the Commission's jurisdiction under section 203. Section 203(a) provides, in relevant part:

No public utility shall sell, lease, or otherwise dispose of the whole of its *facilities subject to the jurisdiction of the Commission,* * * * or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person * * * without first having secured an order of the Commission to do so.[16]

In addition, section 206(d) concerns facilities ''under the jurisdiction of the Commission'':

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of *facilities under the jurisdiction of the Commission* in cases where the Commission has no authority to establish a rate governing the sale of such energy.[17]

2. Legislative History of the FPA

The relevant legislative history of the general purposes of Title II of the FPA, and of section 201 in particular, focuses primarily on bundled sales of electric energy and does not directly address the issue of what constitutes local distribution as opposed to transmission in interstate commerce.

In discussing the general purposes of Title II of the House bill, the House Report states:

Title II * * * establishes for the first time regulation of electric utility companies transmitting energy in interstate commerce.

* * * * *

* * * Under the decision of the Supreme Court of the United States in (Attleboro), the rates charged in interstate wholesale transactions may not be regulated by the States. Part II gives the Federal Power Commission jurisdiction to regulate these rates. A ''wholesale'' transaction is defined to mean the sale of electric energy for resale and the Commission is given no jurisdiction over local rates even where the electric energy moves in interstate commerce.[18]

In its analysis of section 201, the House Report states:

As in the Senate bill no jurisdiction is given over local distribution of electric energy, and the authority of States to fix local rates is not disturbed even in those cases where the energy is brought in from another State.[19]

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[12] A bus is an electrical conductor which serves as a common connection for two or more electrical circuits. Electric Utility Rate Design Study, Glossary: Electric Utility and Ratemaking Load & Management Terms, Edison Electric Institute (Sept. 11, 1978).

[13] There are, of course, facilities that are used to provide delivery to both wholesale purchasers and end users. In those situations, we believe that the Commission and the States have jurisdiction to set rates for the services that are within their respective jurisdictions. That facilities are used to serve resale and retail customers does not, however, necessarily mean that the facilities are local distribution facilities.

[14] 16 U.S.C. 824.

[15] 16 U.S.C. 824(b) (emphasis added).

[16] 16 U.S.C. 824b (emphasis added).

[17] 16 U.S.C. 824e(d) (emphasis added).

[18] H.R. Rep. No. 1318, 74th Cong., 1st Sess. 7–8 (1935).

[19] *Id.* at 27.

The Senate Report's discussion of the general purposes of the FPA states:

The decision of the Supreme Court in (*Attleboro*) placed the interstate wholesale transactions of the electric utilities entirely beyond the reach of the States. Other features of this interstate utility business are equally immune from State control either legally or practically.[20]

In discussing material differences between the final version of the Senate bill and the original version, the Senate Report states:

Subsection (b), formerly (a), which states the subject matter to which the part relates, has been clarified to make plain that it includes interstate transmission where there is no sale and excludes all facilities used only for production of transmission in intrastate commerce or in local distribution.[21]

In discussing section 201 of the Senate bill, the Senate Report further states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in (*Attleboro*) to be beyond the reach of the States. Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines and over the generating facilities which produce energy for interstate transmission and sale. It is obvious that no steps can be taken to secure the planned coordination of this industry on a regional scale unless all of the facilities, other than those used solely for retail distribution, are made subject to the jurisdiction of the Commission. Facilities used only for intrastate commerce or local distribution are expressly excluded from the operation of the act.[22]

The Conference Report adds little description regarding jurisdictional facilities. In reference to section 201(b) it states that:

[T]he language of the House amendment has been followed with a clarifying phrase added to remove any doubt as to the Commission's jurisdiction over facilities used for the generation and local distribution of electric energy to the extent provided in other sections of this part and the part next following.[23]

In addition to the above statements pertaining to section 201 of the FPA, Congress referenced distribution of energy in the legislative history of section 206(d). Section 206(d) was originally enacted as section 206(b) of the FPA. Under the Regulatory Fairness Act of 1988,[24] section 206(b) was redesignated as section 206(d).

The Conference Report on the original FPA does not address section 206(b). The Senate Report on the FPA bill states in pertinent part:

Subsection (b) authorizes the Commission to investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy. * * * Since the rate-making powers granted to the Commission apply only to the wholesale rates of energy sold in interstate commerce, this last subsection should be of great benefit in removing the practical difficulty which the States may encounter in regulating the *interstate distribution rates* which are left under their control. Such rate regulation involves the examination and valuation of property *outside* the State. The task is one requiring an agency with a jurisdiction broader than that of a single State. The authority of the Federal Commission is to render assistance to the State commissions in a way which would preserve and make more effective the jurisdiction which is thus left to the States.[25]

The House Report discusses section 206(b) as follows:

This subsection reaches those situations where electric energy is transmitted in interstate commerce *by the same company which distributes it locally,* and will greatly aid State commissions in fixing reasonable rates in such cases.[26]

Thus, the discussions in the two reports do not appear to contemplate a situation in which the transmitter and seller of electric energy are different, and neither is a ''local'' distributor. The House Report expressly refers to the same company being the transmitter and seller of electric energy. The Senate Report by its terms addresses the regulation of interstate distribution rates.[27]

The above legislative history on sections 201 and 206(b) does not provide any definitive answers to the questions raised. We therefore turn to the case law under the FPA.

3. Case Law Under the FPA

Jersey Central was the first of the major FPC jurisdictional cases considered by the Supreme Court. The case involved the acquisition by New Jersey Power and Light Company (New Jersey Power) of certain securities of Jersey Central Power & Light Company (Jersey Central) without the Commission's prior approval. The question before the Court was whether Jersey Central was a ''public utility'' under section 201(e)[28] of the FPA so that the Commission's prior approval of the stock acquisition was necessary under section 203 of the FPA.

Jersey Central owned transmission facilities that connected to facilities that Public Service Electric & Gas Company (Public Service) owned. The interconnection of these transmission facilities was in New Jersey. Public Service's facilities in turn connected to the facilities of the Staten Island Edison Corporation (Staten Island Edison), a New York utility, at the mid-channel of Kill van Kull, a body of water separating New Jersey and New York. Jersey Central delivered energy to and received energy from Public Service under contract, and Public Service delivered energy to and received energy from Staten Island Edison under contract.[29]

The Court found that, although Jersey Central generated and received electricity only in New Jersey, some of the electric energy that it dispatched to Public Service ''was instantaneously transmitted to New York.''[30] The Court held that ''[t]his evidence * * * furnishes substantial basis for the conclusion of the Commission that facilities of Jersey Central are utilized for the transmission of electric energy across state lines.''[31] Therefore, the Court found that Jersey Central was a public utility within the meaning of section 201(e).[32]

The Court cited *Attleboro*, in which the Court found that the sale of locally produced electric energy for use in another state resulted in the transmission of electric energy in interstate commerce, even though title passed at the state line.[33] In *Jersey Central*, the Court explained the rationale for federal jurisdiction as follows:

(Section 201(c) of the FPA) defines the electric energy in commerce as that ''transmitted from a State and consumed at any point outside thereof.'' There was no change in this definition in the various drafts of the bill. The definition was used to ''lend precision to the scope of the bill.'' It is impossible for us to conclude that this definition means less than it says * * *. The purpose of this act was primarily to regulate the rates and charges of the interstate energy.[34]

The Court in *Jersey Central* thus interpreted the FPA as placing within the federal province regulation of wholesale sales of electric energy that, in any manner, flows in interstate commerce. The language quoted above and the citation to section 201(c) of the FPA, to be relied upon in subsequent Supreme Court cases, strongly suggested that the Commission's jurisdiction was not based on whether there was a sale by the utility, but rather on the flow of electric energy either into or out of a state, so long as the energy crosses state lines.

CL&P, which was decided two years after *Jersey Central*, is the leading case interpreting

[20] S. Rep. No. 621, 74th Cong., 1st Sess. at 17 (1935). *See id.* at 18 (''The revision [between the original and final versions of the Senate bill] has also removed every encroachment upon the authority of the States. The revised bill would impose Federal regulation only over those matters which cannot effectively be controlled by the States.'')

[21] *Id.* at 19.

[22] *Id.* at 48. The provisions of the Senate bill regarding federal jurisdiction over generating facilities were eliminated from the final version of the bill.

[23] H.R. Conf. Rep. No. 1903, 74th Cong., 1st Sess. 74 (1935).

[24] Pub. L. No. 100–473, 102 Stat. 2299 (1988).

[25] S. Rep. No. 621, 74th Cong., 1st Sess. 51 (1935) (emphasis added).

[26] H.R. Rep. No. 1318, 74th Cong., 1st Sess. 29 (1935) (emphasis added).

[27] The Senate Report states that interstate distribution rates are left in the States' control. Obviously, the Senate drew a distinction between interstate distribution (left in the States' control) and interstate transmission (given to the FPC). *Compare* S. Rep. No. 621 at 49 *with* H.R. Rep. No. 1318 at 51.

[28] Section 201(e) defines a ''public utility'' as ''any person who owns or operates facilities subject to the jurisdiction under this Part (other than facilities subject to such jurisdiction solely by reason of section 210, 211, or 212).'' 16 U.S.C. 824(e). The section as adopted in 1935 did not contain the parenthetical, which was adopted in 1978 as part of the Public Utility Regulatory Policies Act.

[29] *Jersey Central*, 319 U.S. at 63–65.

[30] *Id.* at 66.

[31] *Id.* at 67 (citation omitted).

[32] *Id.* at 73.

[33] 273 U.S. at 86, 89–90.

[34] 319 U.S. at 71 (footnote omitted).

the section 201(b) local distribution proviso. In *CL&P*, the Commission sought to regulate the accounting practices of Connecticut Light & Power Company (CL&P).[35] At issue was whether CL&P was a ''public utility'' under the FPA. The utility's system encompassed an area solely within a single state (Connecticut)[36] and did not interconnect with any other company that operated out of state.[37] ''Its purchases and sales, its receipts and deliveries of power, (were) all within the state.''[38] However, CL&P did purchase energy from companies that had, in turn, purchased energy from Massachusetts. The company also sold energy to a municipality that exported a portion of that energy to Fishers Island, located off the coast of Connecticut but ''territory of New York.''[39] The Commission based its jurisdiction on these few transactions.[40]

The Court of Appeals affirmed the Commission, holding that the Commission's jurisdiction extended to ''electric distribution systems which normally would operate as interstate businesses.'' The Court of Appeals found that:

Whether or not the facilities by which petitioner distributes energy from Massachusetts should be classified as 'local' is not relevant to this case. The sole test of jurisdiction of the Commission over accounts is whether these facilities, 'local' or otherwise, are used for the transmission of electric energy from a point in one state to a point in another.([41])

The Supreme Court reversed. It held that the statutory language in section 201(b) of the FPA providing that the Commission ''shall not have jurisdiction * * * over facilities used in local distribution'' is a limitation upon Commission jurisdiction that ''the Commission must observe and the courts must enforce.''[42] In analyzing the statute, the Court stated:

It has never been questioned that technologically generation, transmission, distribution and consumption are so fused and interdependent that the whole enterprise is within the reach of the commerce power of Congress, either on the basis that it is, or that it affects, interstate commerce, if at any point it crosses a state line.

* * * * *

But whatever reason or combination of reasons led Congress to put the provision in the Act, we think it meant what it said by the words ''but shall not have jurisdiction * * * over facilities used in local distribution.'' Congress by these terms plainly was trying to reconcile the claims of federal and local authorities and to apportion federal and state jurisdiction over the industry.[43]

The Court decided that this limitation on jurisdiction was ''a legal standard that must be given effect in this case in addition to the technological transmission test.''[44]

The Court stated that whether or not local distribution facilities carried out-of-state electric energy was irrelevant. Whatever the origin of the electric energy they carried, so long as the utility used the lines for local distribution,[45] they were exempt from federal jurisdiction.[46] In fact, the Court stated that local distribution facilities ''may carry no energy except extra-state energy and still be exempt under the Act.'' *Id.* at 531. The Court concluded that the Commission's order:

Must stand or fall on whether this company owned facilities that were used in transmission of interstate power and which were not facilities used in local distribution.[47]

Upon reversing the Court of Appeals, the Court commented, in dictum, on the evidence the Commission had relied upon in finding that the facilities in question were used for transmission. It noted that the Commission had relied upon certain gas transportation cases in concluding that transmission extends from the generator to the point where the function of conveyance in bulk over distance is completed and the process of subdividing the energy to serve ultimate consumers, which is the characteristic of ''local distribution,'' is begun. The Court cautioned:

But a holding that distributing gas at low pressure to consumers is a local business is not a holding that the process of reducing it from high to low pressure is not also part of such local business. In so far as the Commission found in these cases a rule of law which excluded from the business of local distribution the process of reducing energy from high to low voltage in subdividing it to serve ultimate consumers, the Commission has misread the decisions of this Court. No such rule of law has been laid down.[48]

The Court also noted in its dictum, however, that once a company is properly found to be a ''public utility'' under the Act, the fact that a local commission may also have jurisdiction does not preclude exercise of the Commission's functions. *Id.* at 533.[49]

The Court instructed the lower court to remand the case to the Commission for a finding regarding whether the facilities in question were used in local distribution.[50]

The *CL&P* case was ultimately disposed of without the Commission having made a finding that the facilities were used in local distribution. While the Commission found that it was ''extremely doubtful'' that it could find that the facilities in question were not local distribution facilities, 6 FPC 104, 106 (1947), the Commission did not articulate a definition of local distribution facilities.

In *Wisconsin-Michigan Power Co.* v. *Federal Power Commission*,[51] the Seventh Circuit held that a utility was a jurisdictional public utility where it operated two divisions in Wisconsin and Michigan in a coordinated manner such that electric energy from one state was transmitted to the other, and vice versa, ''in appreciable amounts by the power company and by it commingled with energy generated in the two respective districts and then delivered to the [wholesale] customers * * *.''[52] The court also rejected the notion that the energy changed its form or character when it was stepped down in voltage before it reached the wholesale purchasers.[53]

The court in *Wisconsin-Michigan* distinguished between transmission and local distribution by focusing on wholesale sales of electric energy versus retail sales (''local rates'') of electric energy. It cited the House Report on the FPA, and characterized the legislative history as follows:

The legislative history, (H.R. Rep. No. 1318), 74th Cong., 1st Sess. pages 7, 8 and 27 (1935), discloses that the Congressional Committee intended that *the provisions of the (FPA) should apply to the transmission of electric energy in interstate commerce, i.e., the sale of energy at wholesale in interstate commerce, but not to the retail sale of any such energy in local distribution;* that the (FPA) left to the state the authority to fix local rates where the energy is brought in from other states, and that the rate making power of the (FPC) was to be confined to those *wholesale transmissions* which the Supreme Court had held in (*Attleboro*) to be beyond the reach of the state. Under that decision, said the committee, the rates charged in interstate wholesale transactions could not be regulated by the states. It defined a wholesale transaction as the sale of electric energy for resale.[54]

The Seventh Circuit's characterization of the House Report seems to equate transmission of electric energy in interstate commerce with the sale of energy at wholesale in interstate commerce. However, this interpretation is at odds with both the

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[35] *CL&P*, 324 U.S. at 517.

[36] *Id*. at 518.

[37] *Id*. at 521.

[38] *Id*. at 522.

[39] *Id*. at 519–21.

[40] *Id*.

[41] *Id*. at 522, *quoting* Connecticut Light & Power Co. v. FPC, 141 F.2d 14, 18 (D.C. Cir. 1944).

[42] 324 U.S. at 529.

[43] *Id*. at 529–31.

[44] Id. at 531.

[45] It appears that while the Company received power (at one location) at 66 kV, it primarily owned facilities at 13.8 kV and below.

[46] 324 U.S. at 531.

[47] *Id.* at 531 (emphasis added).

[48] *Id.* at 534.

[49] *See* United States v. Public Utilities Commission of California, 345 U.S. 295, 316 (1953) (*Public Utilities Commission*): Certainly the concrete fact of resale of some portion of the electricity transmitted from a state to a point outside thereof invokes federal jurisdiction at the outset, despite the fact that the power thus used traveled along its interstate route ''commingled'' with other power sold by the same seller and eventually directly consumed by the same purchaser-distributor.

See also Arkansas Power & Light Co. v. FPC, 368 F.2d 376, 383 (8th Cir. 1966) (''Where a company is in fact a public utility, all wholesale sales for resale in interstate commerce are subject to the provisions of sections 205 and 206 of the (FPA), regardless of the facilities used.''). The Eighth Circuit further noted that the section 201(b) exemption applies to a company's status as a public utility and not to the Commission's jurisdiction over sales in interstate commerce for resale. *Id.*, citing *Public Utilities Commission, Colton, infra,* and *Wisconsin-Michigan, infra.*

[50] *Id.* at 536.

[51] 197 F.2d 472 (7th Cir. 1952), *cert. denied,* 345 U.S. 934 (1953) (*Wisconsin-Michigan*).

[52] *Id.* at 474.

[53] *Id.* (''Obviously the energy thus transmitted in interstate commerce is not changed in form or in character except that the voltage is reduced to an extent consistent with efficient economic management and operation.'').

[54] 197 F.2d at 476 (emphasis added).

plain words of the statute as well as the language of the House Report, both of which refer to transmission in interstate commerce separately from sales for resale in interstate commerce.[55] In addition, the Senate Report, which the Seventh Circuit did not mention, clearly recognized jurisdiction over all interstate transmission lines, whether or not a sale of energy is carried by those lines.[56]

The *Wisconsin-Michigan* court also cited analogous natural gas cases, stating that ''[t]he question is essentially, when does interstate commerce transportation end and where do the local distribution facilities first become operative.'' [57] The court further stated that:

(U)pon delivery to (the wholesaler) local distribution begins when he resells. His sales and distribution at retail are clearly local in character, and constitute only local distribution; but at no point before delivery to him has been completed, has interstate transmission terminated. In other words, ''facilities used in local distribution'' means facilities used for making resale and distribution to consumers, jurisdiction over which is left to the states. It was only because of this conclusion that the Supreme Court said, (citation omitted), the Act ''cut(s) sharply and cleanly between sales for resale and direct sales for consumptive uses.'' We think there is no ground for the position that local distribution includes any transmission occurring before the wholesaler who resells at retail is reached.[58]

The Seventh Circuit concluded that the sales for resale were made in interstate commerce; that local distribution had not begun; that the interstate character of the transmission persisted until delivery to the wholesaler; that, up to that point, no local distribution facilities were in operation and that, therefore, the sales were subject to Commission regulation.

In *Federal Power Commission v. Southern California Edison Company* (the *Colton* case),[59] the Supreme Court held that the FPA provides a clear line of demarcation between jurisdictional transactions and non-jurisdictional transactions. However, this case, too, involved bundled sales of electric energy. In the facts of the case, Southern California Edison Company (Edison) admitted that it was a public utility by virtue of owning two interstate transmission lines.[60] At issue was whether its sales of electric energy to the City of Colton, California, for resale to Colton's retail customers, were jurisdictional. Included in the electric energy that Edison sold to Colton was out-of-state electric energy from Hoover Dam.[61] The Commission ruled that the sale to Colton was a sale of electric energy at wholesale in interstate commerce subject to regulation under the FPA.[62] In upholding the Commission, the Court held that Edison's importation of out-of-state electricity for resale to Colton sufficed to confer federal jurisdiction.

The Court, citing an earlier Supreme Court case,[63] characterized Congressional intent in the FPA:

(W)hat Congress did was to adopt the test developed in the *Attleboro* line which denied state power to regulate a sale ''at wholesale to local distributing companies'' and allowed state regulation of a sale at ''local retail rates to ultimate consumers.'' [64]

The Court rejected the argument that FPC jurisdiction was confined to those interstate wholesale sales constitutionally beyond the power of state regulation by force of the Commerce Clause, and was to be determined on a case-by-case analysis of the impact of state regulation upon the national interest. The Court stated that in the FPA:

(C)ongress meant to draw a bright-line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extend[ed] it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.[65]

The Court held that ''(t)here is no such exception covering the Edison-Colton sale.'' [66]

Parties in the Colton case had raised the question of whether jurisdiction over the Colton sale was prevented by the ''local distribution'' proviso of section 201(b). The Court stated that whether facilities are local distribution facilities is a matter for the Commission to decide in the first instance. Citing *CL&P, supra,* it stated:

Whether facilities are used in local distribution—although a limitation on FPC jurisdiction and a legal standard that must be given effect in addition to the technological transmission test * * *—involves a question of fact to be decided by the FPC as an original matter.[67]

The Court cited evidentiary support and the Commission's expertise in such matters in upholding the Commission's determination that certain facilities owned by Edison were used exclusively to effect the wholesale sale to Colton and not for local distribution. Such facilities included 12 kV lines that served an industrial customer, several lighted highway signs, a residence and a railroad section house before they reached the transformers in the Colton substation. The FPC had held that those uses prior to the lines reaching the Colton substation did not transform the lines into local distribution facilities.[68]

In *Duke Power Company* v. *Federal Power Commission* (*Duke*),[69] the D.C. Circuit held that a public utility's acquisition of facilities used solely in local distribution, and which would continue to be used for local distribution, was beyond the Commission's jurisdiction under section 203. The case involved Duke Power Company's (Duke's) proposed acquisition of facilities owned by Clemson University (Clemson), which were used to distribute electricity off-campus to customers (primarily university personnel) in two South Carolina counties. Clemson purchased the power at wholesale from Duke. No one appeared to contest the conclusion that the 7 miles of distribution line and 418 service connections owned by Clemson were ''local distribution'' facilities.[70] Rather, the case turned on interpreting section 203 and whether it was intended to affect *only* acquisitions of jurisdictional facilities, or also to affect acquisitions of non-jurisdictional facilities. In interpreting section 203, however, the D.C. Circuit extensively analyzed and discussed the fundamental jurisdictional lines that Congress drew in section 201.

Citing to the *CL&P* case, the court in *Duke* stated:

The Act, as we have seen, effectuated federal control over the transmission and the sale at wholesale of electric energy in interstate commerce, and established the Commission's regulatory power over public utilities engaging in *either* of these pursuits.[71]

However, quoting *CL&P*, the court further stated:

The expression ''facilities used in local distribution'' is one of relative generality. But as used in this Act it is not a meaningless generality in the light of our history and the structure of our government. We hold the phrase to be a limitation on jurisdiction and a legal standard that must be given effect in this case in addition to the technological transmission test.[72]

The court further rejected the Commission's concept that, in order to determine whether jurisdiction over any particular acquisition existed, the impact of local supervision be measured on a case-by-case basis. Quoting from *Colton*, the court stated:

[T]his ''flexible approach''—involving as it does the consideration, *inter alia*, of ''the

[55] *See* H.R. Rep. No. 1318 at 27. (''Subsection (b) confers jurisdiction upon the Commission over the transmission of electric energy in interstate commerce *and* the sale of electric energy in wholesale in interstate commerce * * *.'' emphasis added).

[56] *See* S. Rep. No. 621 at 48 (''Jurisdiction is asserted over all interstate transmission lines whether or not there is a sale of the energy carried by those lines * * *.'').

[57] 197 F.2d at 477.

[58] *Id.*, citing FPC v. East Ohio Gas Co., 338 U.S. 464 (1950) (*East Ohio*).

[59] 376 U.S. 205 (1964) (*Colton*).

[60] The Supreme Court noted that Edison's status as a public utility did not decide the question of whether the FPC could assert jurisdiction over the rates for the Edison-Colton sale. *Id.* at 208 n.3.

[61] *Id.* at 208, 209 & n.5.

[62] *Id.* at 208. *See* Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission, 461 U.S. 375, 380 (1983) (''(*Colton*) held, among other things, that * * * a California utility that received some of its power from out-of-state was subject to federal and not state regulation in its sales of electricity to a California municipality that resold the bulk of the power to others.'').

[63] Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 504 (1942).

[64] 376 U.S. at 214.

[65] *Id.* at 215–216.

[66] *Id.* at 216 (footnote omitted).

[67] *Id.* at 210 n.6 (citation omitted).

[68] *Id.* at 210 n.6.

[69] 401 F.2d 930 (D.C. Cir. 1968) (*Duke*).

[70] Duke delivered power to Clemson at a distribution voltage of 4,160 volts. The step-down transformers by which the voltage was reduced, and the substations at which the delivery was effected, were owned by Duke. 401 F.2d at 931, n.8.

[71] 401 F.2d at 938–39 (emphasis added, footnotes omitted).

[72] *Id.* (footnote omitted).

effect of the regulation upon the national interest in the commerce''—has been flatly rejected as a technique for resolving jurisdictional conflicts between the Commission and state bodies. * * * We think that like the line ''(i)t cut sharply and cleanly between sales for resale and direct sales for consumptive uses'' to facilitate jurisdictional determinations in rate regulation, ''Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis,'' in distributing regulatory power over the acquisition of facilities.[73]

The court rejected the Commission's argument that jurisdiction over the merger or consolidation of jurisdictional facilities with those of any other ''person'' under section 203 gave the Commission jurisdiction over Duke's acquisition. The court stated that the FPA reflects a policy ''' that matters largely of a local nature, even though interstate in character, should be handled locally and should receive the consideration of local [officials] familiar with the local conditions in the communities involved.' '' [74]

Federal Power Commission v. *Florida Power & Light Company* [75] is the last major court case to address the Commission's transmission jurisdiction. In this case, the Commission sought to impose its accounting rules upon Florida Power & Light Company (Florida Power & Light). The company's system lay solely within the borders of Florida and did not directly connect with any out-of-state utility.[76] The Commission held that Florida Power & Light did own facilities that transmitted electric energy in interstate commerce, but the Court of Appeals for the Fifth Circuit ruled that the Commission did not have substantial evidence to support its finding.

The Supreme Court reversed. The Supreme Court noted that Florida Power & Light was a member of the Florida Power Pool along with Florida Power Corporation (Florida Power Corp.).[77] In turn, Florida Power Corp. connected with Georgia Power Company (Georgia Power) at a ''bus'' [78] south of the Georgia-Florida border.[79] Florida Power Corp. regularly exchanged power with Georgia Power.[80] In many instances, Florida Power Corp. transferred power to Florida Power & Light instantly after receiving power from Georgia Power, and transferred power to Georgia Power immediately after receiving power from Florida Power & Light.[81] The Supreme Court found that power commingled in the bus moved across state lines, and concluded that Florida Power & Light engaged in transmission in interstate commerce. The Court held that, to establish jurisdiction, the Commission need only show that ''some (Florida Power & Light) power goes out of State.'' [82] The Court further explained that ''(i)f any (Florida Power & Light) power has reached Georgia, *or* (if Florida Power & Light) makes use of any Georgia power * * * FPC jurisdiction will attach * * *.''[83]

There is also a line of cases that address, among other things, what constitutes a Commission jurisdictional ''sale of electric energy at wholesale'' [84] under section 201 of the FPA.[85] These cases all concerned bundled sales. While the issues posed above involve unbundled wheeling, the ''resale'' cases are helpful to the extent they suggest that local distribution takes place only *after* power is subdivided. *See, e.g.*, 345 U.S. at 316 (''the facilities supplied 'local distribution' only after the current was subdivided for individual consumers.'').

4. Natural Gas Act

The Natural Gas Act (NGA) was adopted in 1938. Like the FPA, the NGA contains language limiting the Commission's jurisdiction in situations involving local distribution.[86]

Section 1(b) of the NGA provides:

The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural gas companies engaged in such transportation or sale, *but shall not apply* to any other transportation or sale of natural gas or *to the local distribution of natural gas or to the facilities used for such distribution* or to the production or gathering of natural.[87]

There is similarity in many respects between the House and Senate Reports on the FPA and the NGA with respect to the jurisdiction given the Commission. For example, all four reports mention *Attleboro* as placing interstate wholesale transactions beyond the reach of the States. As indicated in the House Report on the NGA, the States could ''regulate sales to consumers even though such sales are in interstate commerce, such sales being considered local in character and in the absence of congressional prohibition subject to State regulation.'' (*See* H.R. Rep. No. 709, 75th Cong., 1st Sess. 1). However, the House and Senate Reports on the NGA contain identical language not found in the reports on the FPA:

In view of the importance of section 1(b), which states the scope of the act, it seems advisable to comment on certain provisions appearing therein. It will be noted that this subsection of the bill, after affirmatively stating the matters to which the act is to apply, contains a provision specifying what the act is not to apply to, as follows:

But shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

The quoted words are not actually necessary, as the matters specified therein could not be said fairly to be covered by the language affirmatively stating the jurisdiction of the Commission, but similar language was in previous bills, and, rather than invite the contention, however unfounded, that the elimination of the negative language would broaden the scope of the act, the committee has included it in this bill. *That part of the negative declaration stating that the act shall not apply to ''the local distribution of natural gas'' is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character.* (Emphasis added).[88]

As a result of this language it can be argued that Congress considered distribution (and local distribution) only in the context of bundled retail sales of natural gas. In fact, it appears that all of the court cases affirming the states' right to regulate local distribution of gas have involved bundled retail sales. *See Panhandle Eastern Pipe Line Co.* v. *Michigan Public Service Commission*, 341 U.S. 329 (1951) (*Panhandle*). There the Court, in affirming the State of Michigan's right to regulate an interstate pipeline's proposed bundled retail sales of gas to industrial consumers, noted that the pipeline company proposed to lay pipeline in ''the streets and alleys of Detroit'' and ignored the local distribution company's request for additional gas to meet the increased needs of the industrial consumers. *Id.* at 333. While the Court based its holding on a state's authority to regulate direct (retail) sales to an end-user, rather than on the basis of the section 1(b) local distribution provision, it also found that the proposed sales were ''primarily of local interest'' and ''emphasized the need for local regulation.'' *Id.* Two years before *Panhandle,* the Supreme Court issued its decision in *FPC* v. *East Ohio Gas Co.*, 338 U.S. 465 (1949) (*East Ohio*). East Ohio Gas Company owned and operated a natural gas business wholly within the State of Ohio. The company sold gas only to Ohio customers but most of the gas was transported to Ohio from other states by interstate pipelines. These interstate pipelines connected inside Ohio with East Ohio's large high pressure lines. The gas then was transported over 100 miles through East Ohio's system to its local distribution system. East Ohio argued that it was exempt from Commission jurisdiction because all of its facilities were local distribution.

The Court disagreed, finding the Commission's jurisdiction extends over the

[73] *Id.* at 949 (footnotes omitted).

[74] *Id.* at 936 (quoting from Hearings on H.R. 5423 before the House Committee on Interstate and Foreign Commerce, 74th Cong., 1st Sess. 393 (1935) (testimony of then-FPC Commissioner Seavey)).

[75] 404 U.S. 453, *reh'g denied*, 405 U.S. 948 (1972) (*Florida Power & Light*).

[76] 404 U.S. at 456.

[77] *Id.* at 456.

[78] A ''bus'' is a connector or group of connectors that serves as a common connection for two or more circuits.

[79] 404 U.S. at 457.

[80] *Id.*

[81] *Id.* at 457 & n.8.

[82] *Id.* at 461. (emphasis omitted).

[83] *Id.* at 461 n.10. (emphasis added).

[84] *See* Section 201(d), 16 U.S.C. 824(d) (1988).

[85] *Public Utilities Commission, supra* note 345; City of Oakland, California v. FERC, 754 F.2d 1378 (9th Cir. 1985) (*Oakland*). See also Alexander v. FERC, 609 F.2d 543 (D.C. Cir. 1979) (*Alexander*).

[86] Courts often rely on cases construing the NGA when interpreting the FPA, and vice versa. *E.g.*, Arkansas Louisiana Gas Co. v. Hall, 453 U.S. 571, 577 n.7 (1981).

[87] 15 U.S.C. 717(b) (emphasis added).

[88] H.R. Rep. No. 709, 75th Cong., 1st Sess. 3 (1937); S. Rep. No. 1162, 75th Cong., 1st Sess. 3 (1937).

transportation of gas in interstate commerce through high-pressure transmission lines and that distribution did not begin until the point where pressure is reduced and gas enters local mains. The Court stated that: ''[w]hat Congress must have meant by 'facilities' for 'local distribution' was equipment for distributing gas among customers within a particular local community, not the high-pressure pipelines transporting the gas to the local mains.'' [89]

The Commission relied in part on *East Ohio's* high pressure/low pressure distinction in a recent NGA section 7 certificate case which authorized construction of facilities to bypass the local distribution company.[90] On appeal, the California Commission argued that under section 1(b) it should at least have ''jurisdiction over the 'taps, meters and other tie-in facilities' that link the pipeline to end users.'' [91] The court disagreed:

While as a matter of ordinary English 'local distribution' might be understood to encompass any delivery to an end user, that is hardly the only or even more plausible reading. Distribution conjures up receiving a large quantity of some good and parcelling it out among many takers.[92]

After reviewing the report language discussed above, the court also stated:

Insofar as congressional committees spoke to the matter * * * they appear to have viewed distribution as confined to its parcelling out function and (probably) even more narrowly, to parcelling out *accompanied by* retail sales. [93]

In *Cascade Natural Gas Corporation* v. *FERC, et al.* (*Cascade*), the court affirmed the Commission's authorizing an interstate pipeline under section 7 of the NGA ''to construct a tap and meter facility that would allow it to deliver natural gas directly to two industrial consumers * * *.''[94] To reach the interstate pipeline, the industrials constructed a nine-mile pipeline. Together, the facilities bypassed the local distribution company.[95]

The court rejected arguments that section 1(b) deprived the Commission of jurisdiction holding that:

''Local distribution,'' as Congress viewed the term, involves two components: the retail sale of natural gas and its local delivery, normally through a network of branch lines designed to supply local consumers.[96]

[89] 338 U.S. at 469–70.

[90] *See* Mojave Pipeline Company, 35 FERC ¶ 61,199 (1986), *reh'g denied,* 41 FERC ¶ 61,040 (1987), *reh'g denied,* 42 FERC ¶ 61,351 (1988); *see also* Mojave Pipeline Company, 66 FERC ¶ 61,194 (1994), *reh'g pending.*

[91] *See* Public Utilities Commission of the State of California v. FERC, *et al.,* 900 F.2d 269, 273 (D.C. Cir. 1990) (footnote omitted) (*WyCal*).

[92] *Id.* at 276.

[93] *Id.* (emphasis in original).

[94] 955 F.2d 1412, 1414 (10th Cir. 1992).

[95] Unlike the situation in *WyCal* where the pipeline made direct sales to end users, in *Cascade* the pipeline transported gas purchased from third parties. *See* Northwest Pipeline Corporation, 51 FERC ¶ 61,289 at 61,909 (1990).

[96] *Cascade,* 955 F.2d at 1421.

5. Analysis

a. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

The case law supports the conclusion that any facilities of a public utility used to deliver electric energy in interstate commerce to a wholesale purchaser, whether such facilities are labeled ''transmission,'' ''distribution'' or ''local distribution,'' are subject to the Commission's jurisdiction under sections 205 and 206.

This conclusion is supported by *Public Utilities Commission, supra,* in which the Supreme Court, in the section of its opinion addressing the section 201(b) local distribution provision, held that local distribution facilities began ''only after the current was subdivided for individual consumers.'' [97] *Wisconsin-Michigan, supra,* in which the Seventh Circuit held that there is no local distribution until the wholesaler who re-sells at retail is reached, is to like effect.

This conclusion, which results in a ''functional'' line being drawn to determine Commission jurisdiction, is not only consistent with the case law under section 201, but is also consistent with our interpretation of the line drawn under newly amended FPA sections 211 and 212. As long as electric energy is being sold to a legitimate wholesale purchaser, we believe the Commission has jurisdiction under sections 201, 205, and 206 of the FPA over the public utility's facilities used to deliver electric energy to that purchaser.

b. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier directly to an end user?

In analyzing jurisdiction over unbundled retail wheeling, we believe it is important to distinguish between unbundled wheeling provided by the public utility who previously provided bundled retail service to the end user, and unbundled wheeling provided by other public utilities to the end user. For example, a former bundled retail customer may need unbundled wheeling services from its previous public utility generation supplier, as well as unbundled wheeling from one or more intervening public utilities, in order to reach a distant generation supplier. In this scenario, the Commission believes it would have jurisdiction over all of the facilities used for the unbundled wheeling provided by the intervening public utilities.[98] The more difficult issue is whether some portion of the facilities used to transmit energy from the transmitting utility in closest proximity to the end user (the former supplier of the bundled product) is local distribution facilities. We believe that in most, if not all circumstances, some portion will be local distribution facilities.

[97] 345 U.S. at 316 (footnote omitted).

[98] The Commission would not have jurisdiction over the rates for the sale of generation by the distant supplier because the transaction would be a retail sale of electric energy.

The case law is replete with statements that the local distribution provision of section 201 must be given effect. However, the Supreme Court in both *CL&P* and *Colton, supra,* has stated that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. Thus, there is no clear case law on a ''bright line'' between transmission and local distribution. In addition, regardless of the details of the chain of delivery services necessary to move electric energy from the generator to the end user, in most cases the last public utility in the chain will use facilities that historically were considered local distribution facilities. Accordingly, unlike the situation involving unbundled wholesale wheeling, for which the case law clearly supports a ''functional'' test, the Commission believes the case law and practical realities of a changing industry support an analysis of local distribution facilities based on the facilities' functional as well as technical characteristics.

While it would be preferable to draw an absolutely ''bright'' line (*e.g.,* based on technical characteristics such as voltage), the Commission does not believe this is required by the case law and, importantly, would not be a workable approach in all cases because of the variety of circumstances that may arise and because utilities themselves classify facilities differently (*e.g.,* one utility may classify a 69 kV facility as transmission; another may classify it as distribution).

Therefore, the Commission is adopting several indicators it will evaluate in determining whether particular facilities are transmission or local distribution in the case of vertically integrated transmission and distribution utilities: [99]

- Local distribution facilities are normally in close proximity to retail customers.
- Local distribution facilities are primarily radial in character.
- Power flows into local distribution systems, it rarely, if ever, flows out.
- When power enters a local distribution system, it is not reconsigned or transported on to some other market.
- Power entering a local distribution system is consumed in a comparatively restricted geographical area.
- Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
- Local distribution systems will be of reduced voltage.[100]

In summary, for unbundled wholesale wheeling the Commission will apply a

[99] In the case of a distribution-only utility, which is franchised by a State or local government and sells only at retail, all of the circuits (and related wires, transformers, towers, and rights of way) which it owns or operates (regardless of voltage) would be local distribution facilities.

[100] The Commission has analyzed utilities' filings required by the Commission's regulations. These filings are made on FERC Form No. 1. While there is no uniform breakpoint between transmission and distribution, it appears that utilities account for facilities operated at greater than 30 kV as transmission and that distribution facilities are usually less than 40 kV.

functional test. The only definitive question will be whether the entity to whom the power is delivered is a lawful wholesaler. For unbundled retail wheeling the Commission will apply a combination functional-technical test that will take into account technical characteristics of the facilities used for the wheeling. The Commission concludes that these tests are consistent with the FPA, its legislative history and the case law discussed above.

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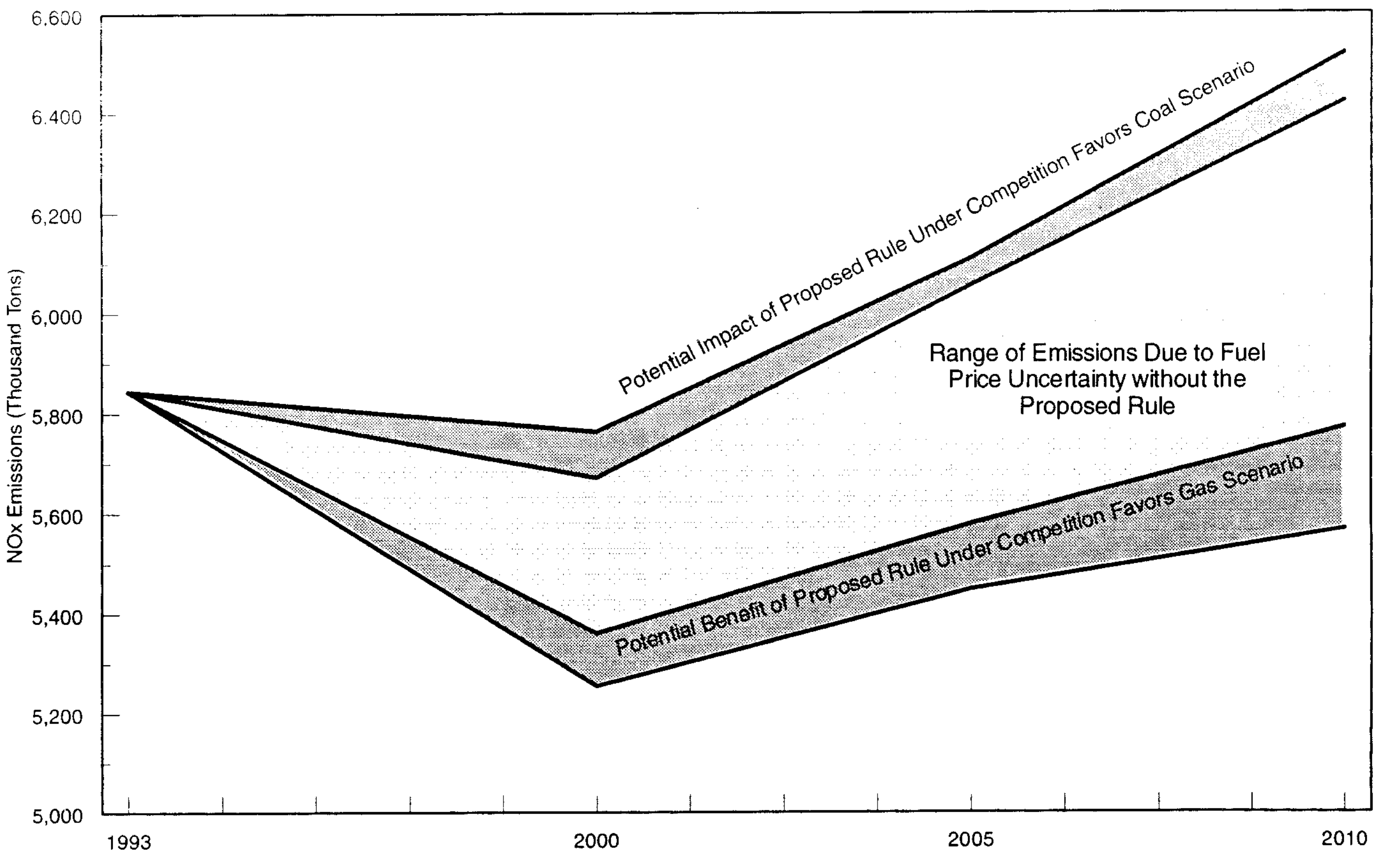
APPENDIX H
Page 1

Figure ES-1. Total U.S. NOx Emissions



Source for 1993 data: Energy Information Administration, *Electric Power Annual.*
Note: All estimates include NOx emissions adjustments for MOU in the Ozone Transport Region.

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APPENDIX H.—TABLE ES–2.—NATIONAL EMISSIONS OF NO_X *as Projected in Both Base Cases and All Proposed Rule Scenarios*
[Thousand tons]

Year	Under assumption that relative gas and coal prices remain constant		Under assumption that gas prices increase compared to coal prices		
	Constant price-differential base case	Competition-favors-gas proposed rule scenario	High-price-differential base case	Competition-favors-coal proposed rule scenario	Low response proposed rule scenario
1993	5,844	5,844	5,844	5,844	5,844
2000	5,362	5,255	5,672	5,763	5,743
2005	5,579	5,449	6,053	6,108	6,056
2010	5,772	5,638	6,426	6,519	6,426

Promoting Wholesale Competition Through Open Access Non- Discriminatory Transmission Services by Public Utilities

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

(As corrected April 25, 1996)

[Docket No. RM95–8–000; Docket No. RM94–7–001]

Issued April 24, 1996.

HOECKER, Commissioner, *concurring in part and dissenting in part:*

General Observations

A. Four years and untold numbers of conferences, studies, and speculations after the Energy Policy Act, the Commission today takes a major step in bringing competition to the wholesale bulk power market in the United States. Order No. 888 (FERC Stats. & Regs. ¶ 31,036), together with our order establishing an open access same-time information system (OASIS) (Order No. 889, FERC Stats. & Regs. ¶ 31,037) and our proposal to conform all transmission tariffs to a uniform capacity reservation system (FERC Stats. & Regs. ¶ 32,517), will set in motion a dynamism seldom witnessed in the electric power business. In that sense, the organizational, operational, and economic consequences of the requirements we adopt today defy prediction. I believe nevertheless that the Commission's Final Rule today is a sound and reasoned decision about the industry as we now know it and as we think it may evolve. I therefore announce my unequivocal support for the order's basic tenets as we have chosen to implement them—the unbundled wholesale utility services, open and non-discriminatory access to transmission and to information about transmission, service comparability, an opportunity for increased competition among generation sources, coordination with and deference to state regulatory interests, and full recovery of eligible stranded investments.

B. Restructuring the electric power industry is a matter of national interest and priority. Electricity is ubiquitous. Its benefits are key to the American quality of life. Operating 750,000 MW of generation capacity arrayed across three synchronous regional transmission grids, the electric industry is the nation's most capital intensive. The 179 largest investor-owned utilities alone control nearly $600 billion in assets. And, total electricity revenues constitute between 3 and 4 percent of the gross domestic product (GDP)—larger than telecommunications, natural gas pipeline, and airline revenues combined.

Both the Congress and the President have recognized our obligation to ensure that these resources are used wisely and efficiently. We all recognize that systemic change is happening within the industry and that regulation must change to take maximum advantage of the most constructive of those forces. ''At the center of the success of our economy is the market, and at the core of the success of the market is competition,'' states the President in his 1996 *Economic Report* to the Congress; ''it is competition that drives down costs and prices, induces firms to produce the goods consumers want, and spurs innovation and the expansion of new markets abroad.'' Yet, as state and local governments consider the future of industries heretofore heavily regulated in the public interest, deregulation is not enough, states the President. Competition must be actively promoted and preserved from the abuses and distortions associated with monopoly power, as well as from outdated forms of regulation that provide inappropriate incentives.

In the electric utility restructuring process, several difficult challenges must still be met here and elsewhere. First, policymakers must make the tough choices to attack access discrimination and promote competition while also ensuring reliability and economical service. Success in these undertakings may require pricing innovation and structural reforms to attain significant long-run gains in efficiency and productivity. *Economic Report,* at 183–185. Second, no transition to a new regime of operating rules and assumptions, can be achieved reasonably if regulated companies are shorn of the opportunity to recover prudently incurred costs. Utility investments that may become stranded or uneconomic as competitive choice displaces franchise monopoly are estimated to represent a $100 billion-plus risk for public utilities. State and federal regulators must confront this issue in the interest of equity and a swift readjustment to the new competitive realities. As the President's *Economic Report* makes clear, it will be important to future suppliers of private capital for public use that a regulatory bargain made must remain a bargain kept. ''Credible government is key to a successful market economy, because it is so important for encouraging long-term investments.'' *Id.,* at 186–188. Third, maintaining competitive parity and environmental protection are key challenges as well. That means, among other things, that environmental policy must respond to the environmental risks associated with restructuring and vice versa. *Id.,* at 188–189. This assessment of the realities and challenges facing this Commission, its state counterparts, and the diverse elements of the industry substantially ratifies the Commission's actions today.

C. The long-run prospect for reform of the wholesale market is promising, though the task seems daunting. The preamble to the Final Rule begins by outlining the difficult issues that await this Commission and the industry: (1) Corporate organizational matters, including the role of independent system operators (ISOs) in promoting more efficient operation of the transmission system on a regional basis; (2) the need for a new merger policy, which I believe must be predicated on a thorough understanding of emerging markets and genuine ratepayer protections instead of a subjective tally of supposed ''benefits''; and (3) further efforts to make greater use of flow-based pricing where appropriate. In adopting the OASIS requirements, we have taken a first step in recognizing that competitive markets do not consist of wires and turbines alone, but of information also. Full competition requires the consolidation of the electron transportation system with the electronic information superhighway.

One thing is abundantly clear: restructuring will require continued innovation and fortitude from our capable staff, cooperation from state regulators, patience and foresight from legislators and, most of all, creativity, responsiveness, and endurance from both utility management and electric consumers.

II. Concurrence on Specific Issues

The Final Rule resolves certain matters of policy and law in ways which, despite my fundamental agreement, I would like to offer some additional perspectives.

A. Coordinating State and Federal Regulatory Interests

Perhaps no single issue will influence the success or failure of restructuring as will the capacity of the FERC and state regulators to reach meaningful accommodations as the electric utility industry becomes increasingly subject to competitive forces. The vertical organization and technological integration of the electric power business contributes to the impression of a regulatory system riddled with gaps and overlaps, interregional inequities, and uncertainty. To the extent that impression predominates in the months to come, the pressure from legislators and the financial community to devise single-minded national solutions to issues of regional or local significance will likely prove irresistible.

The regulation of this industry is a unique exercise in federalism. The Deputy Secretary of Energy wisely acknowledged months ago that, ''the aftermath of FERC's open access rulemaking will put to the test our ability to evolve improved means for unsnarling the governance problems of federal and state authorities.'' Charles B. Curtis, Remarks Before the Third DOE/NARUC National Symposium, December 4, 1995. I find no shortage of good ideas on how to achieve better state, federal, and inter-regional cooperation. But, unanswered questions persist about the availability of sufficient political will and leadership to achieve electricity markets that at once satisfy the need for operational efficiency on a regional level and also provide the ''opportunity for experimentation and market testing with the flexibility to comprehend local differences * * * [that is] the very genius of the federal system.'' *Id.*

Although it remains unclear today whether this challenge will be met, I firmly believe that the Final Rule is a sound resolution of the jurisdictional questions facing this Commission as a result of competition and open access. State PUC comments reflect enormous concern about the potential loss of jurisdiction over some wires and services, if and when ''retail transmission'' becomes unbundled. States raise legal objections to our claim of jurisdiction. While reaffirming our view that the Commission has exclusive jurisdiction over the rate, terms, and conditions of interstate transmission, today's order addresses state concerns squarely—first, by adhering to the practical distinctions between transmission and distribution set forth in the NOPR and, second, by according deference [1] to states where appropriate when

[1] The Commission leaves unexplored the precise meaning of ''deference'' in these circumstances. At

Continued

retail transmission services become subject to a FERC tariff. These accommodations will smooth the transition to a seamless competitive market with full customer choice, if and when individual states initiate retail competition.

While the Final Rule, not unexpectedly, manifests this Commission's strong interest in preventing balkanization of the interstate power market, nothing adopted by the Commission today, including the interpretation of its authority over retail transmission when retail service is unbundled, is inconsistent with the traditional state roles in developing regulatory, social, and environmental requirements and programs suited to the circumstances of their localities. Section I of the Final Rule is emphatic about this.

I will conclude with two observations on matters I believe to be of particular sensitivity to the states. First, it appears to me that state regulators may impose distribution and other non-bypassable charges or other retail requirements on direct access services, even in those circumstances where no distribution facilities can be identified under the functional/technical test. The Final Rule ensures that result by acknowledging state authority over distribution-related services under the FPA.

Second, state authority is traditionally employed to ensure that power production conforms to local economic, environmental, and resource diversity policy preferences. A state may wish, for example, to ensure that a direct access industrial customer is no less obligated to purchase power consistent with the resource diversity or environmental requirements than is that customer's franchise distribution utility. To the extent that state requirements to own or purchase a certain amount of generation from, say, renewable sources are enshrined in utility supply portfolios, those states have direct influence on the economic and environmental consequences of energy consumption in that jurisdiction. Moreover, such requirements ought to be compatible with open access transmission. However, it will be important that state authority over resource procurement be exercised on a not unduly discriminatory basis. In other words, a PUC may not treat in-state and out-of-state suppliers differently. If access over the network is non-discriminatory in nature, the federal regulatory and constitutional interests are arguably satisfied.

B. Environmental Effects of Restructuring

1. Last July, we instructed our staff to prepare an Environmental Impact Statement (EIS) in conjunction with this rulemaking. The Final EIS (FEIS), issued on April 12, 1996, is an impressive and, with respect to the air impacts of electric restructuring, a pioneering work. It considers in detail: (1) The possible environmental consequences of adopting this Rule, including a number of additional analyses requested by commenters, (2) alternative methods of pursuing open access transmission service, (3) a range of environmental mitigation actions proposed by commenters, and (4) the Commission's legal and technical ability to undertake environmental mitigation. On the whole, I find staff's studies to be analytically sound and generally in conformance with my understanding of this agency's powers to engage in environmental mitigation. Moreover, its conclusions and recommendations are thoughtful and well-reasoned. I therefore believe that consideration of the FEIS as part of the Commission's actions today meets our National Environmental Policy Act of 1969 (NEPA) obligations [2] and the requirement of reasoned decisionmaking.

The FEIS highlights a very important public health and social welfare issue, not to mention a matter of great financial importance to certain utilities. To be specific, the FEIS examines potential air quality impacts in the event generation increases from certain coal-fired units. Open transmission access is expected by some to stimulate that additional generation and hence additional nitrogen oxide (NO_X) emissions and related ozone formation. From these projections, a substantive and not altogether constructive debate has ensued. As Section V of the Final Rule describes more fully, the Commission conducted additional studies to respond to comments on the draft EIS, using new recommended baselines for comparison. The results confirm that the air quality impacts of the rule are within reason.

The Commission has satisfied itself that the three most pressing questions have been addressed: (1) What increment of the NO_X emissions problem may be attributable to this Final Rule? (2) Will Final Rule-induced NO_X emission increases be so significant and their impacts sufficiently adverse to justify an alternative regulatory approach, such as ''no action'' on utility restructuring? (3) Short of no action, can the Commission undertake direct actions that mitigate any potential adverse effects? Based on the FEIS, I can find no justification in the cause, size, or certainty of near-term emissions increases for delaying or diluting the Open Access Rule and no clear basis for a FERC-sponsored emissions control regime, even on an interim basis.

2. Having discharged our NEPA obligations, I cannot pretend that this matter of public interest is no longer of any interest or concern to us. Clean air is a birthright. Air emissions are therefore an important concern. I would not relegate this issue to the periphery of our deliberations. If the EIS process accomplishes nothing else, it has familiarized the FERC with the difficulties of addressing the seemingly intractable problem of NO_X emissions. The problem engenders interregional economic and environmental conflicts that can be addressed only by a sophisticated balancing of interests and a selfless commitment to the greater good. EPA and several commenters on our Rule express frustration over the progress being made to reduce NO_X emissions. For this and other environmental issues, such as NO_X waivers, resort to the courts has become customary, and complex technological and economic disputes are the norm. *See e.g., Electric Power Alert*, April 24, 1996, at 29–30.

Regions of the country differ, often vehemently, about the source and effects of ozone-causing emissions and how best to curb the generation and transport of pollutants that create ozone. Utilities in some regions have made commitments and invested heavily to achieve ''attainment'' levels, while the blessings of geography and circumstance have imposed no such burden on others. We recognize in essence that reconciling these interests is a task the Congress has assigned to the EPA. Although the Clean Air Act authorizes EPA to develop a national program to enforce emissions reduction largely through state environmental regulatory efforts (the so-called State Implementation Plans (SIPs)), the statutory process is ponderous in practice. Moreover, even where gains are expected to be made in the form of reduced NO_X emissions (*e.g.*, under EPA's pending rulemaking to set NO_X emissions limitations for certain types of utility boilers), those gains might arguably be offset by future increases in the demand for electricity or, according to some parties, by the additional power generation some say will be encouraged by open access transmission.

The inability to guarantee future NO_X reductions for a variety of reasons that range well beyond this Rule presents formidable challenges. EPA places great faith in the ability of the Ozone Transport Assessment Group (OTAG), a voluntary multi-state organization established in part to set up NO_X emission mitigation mechanism, to address these complex issues and achieve a resolution. It nevertheless appears to me that, for the most part, consensus remains distant. The alternative appears to be an even more protracted EPA procedure.

With respect to the gravamen of this issue (i.e., the establishment of an emissions cap and credit trading system reminiscent of what Congress ordered for sulphur dioxide (SO_2)), this Commission has no real choice but to defer to agencies with jurisdiction by law and special expertise. The EPA has done an outstanding job implementing the market-based SO_2 allowance program. It is widely regarded as both creative and successful.

one extreme, it could mean courteous regard for another's views and, at the other, binding submission to another's judgment. I would, for example, accord state views on cost allocation considerable or presumptive, but not conclusive, weight.

[2] NEPA (42 U.S.C. 4321–4370), the Council on Environmental Quality's (CEQ) regulations promulgated thereunder (40 CFR parts 1500–1508 (1995)), and our own environmental regulations supplementing those of CEQ (18 CFR part 380 (1995)) together establish an important procedural mechanism that was designed, not to impose upon this Commission substantive duties to achieve particular results, but to infuse our decisional processes with a broad awareness of the environmental consequences of our actions. Under NEPA, the Commission must in any applicable instance consider and weigh its core objectives and responsibilities under the Federal Power Act and the impacts of its actions on all aspects of the human environment—economic and social as well as ecological. This exercise requires the Commission to ascertain the availability and consider the feasibility of alternative approaches with lesser impacts. In other words, the Commission's duty is to take a ''hard look'' at the environmental effects of its major actions. Robertson v. Methow Valley Citizens Council, *et al.*, 490 U.S. 332 (1988); Strycker's Bay Neighborhood Council, Inc. v. Karlen, *et al.*, 444 U.S. 223 (1980). The EIS process fulfills that requirement.

OTAG, regardless of any concerns about its processes, brings together a broad range of regional interests, thereby offering an unprecedented opportunity for achieving consensus resolution of this difficult problem.

3. In my view, it behooves this Commission to assist in any way it can, consistent with its expertise and authority, to find consensual solutions. I do not think that means denying polluting utilities access to the transmission system and thereby merely reinforcing their monopoly power. Rather, we must stand ready to assist EPA and OTAG in making competition and environmental responsibility equally attractive. We have begun providing that assistance by ensuring (see II.A. above) that state regulators retain their customary authority under state law to structure the generation and purchase power portfolios of state-regulated utilities. Moreover, the Commission has in the past addressed through its rate jurisdiction various public interest goals, including environmental concerns, intergenerational equities, and least-cost planning needs. For instance, in order to encourage capital investment in pollution control equipment and conservation, the Commission has long allowed utilities to include in rate base the costs of ''construction work in progress'' (CWIP) for pollution control devices and fuel conversion measures that discourage use of certain fossil fuels.[3] In addition, utilities are not eligible for CWIP treatment for plant construction not shown to be the product of integrated resource planning.[4]

With respect to the NO_X issue specifically, the Commission is competent to help facilitate an emissions cap and trading system. For instance, the accounting treatment provided for the cost of SO_2 emissions allowances in rates was done to assist implementation of the Clean Air Act.[5] The same accommodations could be instituted for a NO_X program. Perhaps the greatest potential for DOE–EPA–OTAG–FERC collaboration and consultation involves our knowledge of the industry and, after preparing the FEIS, our familiarity with the NO_X problem itself. That information should be useful beyond the confines of this rulemaking. In addition, the FEIS indicates (at p. 7–22) that we can structure the electronic bulletin board systems we require so as to facilitate the posting of emissions data required by EPA.

4. Based upon the mutual concerns and the different but complementary expertise of the affected agencies, I encourage the development of consultative mechanisms, memoranda of understanding, or other procedures that will support and help ensure the success of OTAG's efforts. Such efforts must be consistent with the goals and allocation of responsibilities under the Clean Air Act, and our own regulatory role. Restructuring may pose some environmental risks. We think they are small and (at least eventually) manageable. Further experience is likely to demonstrate that restructuring opens up new possibilities for addressing longstanding environmental problems associated with utility operations. Open access enhances the prospects for environmental dispatch on a statewide or regional basis. It gives isolated renewable plants, particularly hydroelectric and wind power units that are tied to specific geographical features, better market access. I must note that investments in DSM and renewable resources, which offer relatively stable costs, may be an attractive component of utilities' generation portfolios because they also minimize risks. And, as restructuring makes electricity a more customer-driven business, the public's documented preference for environmentally benign power will become more powerful. In addition, efficient markets provide the necessary means to ''marketize'' environmental rules and perhaps to modify siting and other regulatory processes that are predicated on the vertical integration of the utility sector. And, finally, energy services companies that can promote conservation and generation alternatives require more open and dynamic markets. For the environment, the prospects offered by restructuring are exciting. Inhibiting or stopping its development will not help it.

III. Partial Dissent

The Final Rule announces that the Commission will be the ''primary forum'' to hear stranded cost claims where a retail power customer turns wholesale wheeling customer, usually through a municipalization (Situation 2). Although the Final Rule recognizes that states *do* have authority to deal with stranded costs in Situation 2, the majority nevertheless instructs parties to bring their claims to this Commission ''in the first instance.'' However, where costs are stranded due to state authorized retail wheeling (Situation 3), the majority takes a different and, I contend, incongruent approach that effectively denies any forum for those costs if state regulators possess authority to act but do not do so. Because I find nothing in policy or law to commend this approach, I respectfully dissent.[6]

I take issue with the ''primary forum'' approach because I believe that it: (1) Requires the Commission to second-guess state determinations on recovery of costs incurred at retail at a time when many states are addressing the issue; (2) will encourage forum shopping; and (3) is inconsistent with our approach in the retail wheeling situation; and (4) involves an unnecessary legal risk for the Commission.

A. Second-Guessing State Determinations of Retail Stranded Costs is Unwise and Unnecessary

The Final Rule's stranded cost recovery methodologies and the underlying jurisdictional assumptions are aimed at achieving full recovery of all legitimate, verifiable and prudent stranded costs, consistent with a utility's reasonable expectations and the justness and reasonableness of the underlying contract. I believe that this is a worthy objective, but it is not one which requires the Commission to second-guess state determinations. As state proceedings now reveal, the Commission's leadership in raising this issue has borne fruit. Where municipalization is occurring, states are addressing stranded costs responsibly. In nearby Virginia, for example, the Virginia State Corporation Commission has interceded into the dispute between Virginia Electric Power Company and the City of Falls Church over the City's plans to undertake a ''muni-lite'' form of municipalization. Moreover, the record before us today does not endorse the view that municipalization constitutes a major bypass threat to stranded cost recovery.

Notwithstanding such developments, the Final Rule announces that the Commission will be the ''primary forum'' to hear stranded cost claims where a retail power customer turns wholesale wheeling customer, usually through a municipalization. While declaration of ''primary forum'' status sounds very legalistic, there is in fact no legal basis for it. The policy is not founded on a concept of federal preemption in the area. Indeed, the Federal Power Act provides no basis for preemption. Moreover, the Final Rule recognizes that states *do* have authority to deal with stranded costs in these circumstances. The majority's instruction to bring claims directly to FERC will, if anything, afford states a reason to avoid this difficult issue altogether.

B. The ''Primary Forum'' Approach May Encourage Forum Shopping

As a policy matter, the majority's approach is peculiar on its face. Although the ''primary forum'' approach is intended to eliminate forum shopping, it will not achieve even that objective. Indeed, I think the ''primary forum'' approach may encourage parties to forum shop. State commissions or legislatures will often provide for stranded cost recovery at the time the wholesale entity is formed. Similarly, condemnation proceedings may provide for stranded costs in whole or part. Moreover, standards for stranded cost recovery are occasionally prescribed by statute. In reality, the Commission cannot preclude the states from acting on stranded cost issues and our proposed rule may encourage rather than discourage forum shopping.

C. The ''Primary Forum'' Approach Covers Fact Situations Largely Indistinguishable From the Retail Wheeling Scenario

The majority's decision to take primary jurisdiction of costs where a retail power customer becomes wholesale wheeling customer through municipalization and to distance itself from virtually any cost recovery responsibility where retail power customers becomes retail wheeling customers does not withstand scrutiny. These are not factually distinguishable cases, insofar as jurisdiction over stranded costs is concerned. The inadequacy of the majority's reasoning is palpable because it has adopted very different policies with respect to two stranded cost situations that, if properly understood, are virtually indistinguishable.

[3] 18 CFR 35.25 (1995).

[4] 18 CFR 35.13(h)(38) (1995).

[5] Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990, Order No. 552, III FERC Statutes and Regulations ¶30,967 (1993).

[6] My views conform generally to Commissioner Massey's partial dissent today.

First, in both Situations 2 and 3, retail power costs are stranded by customers who gain access to FERC jurisdictional transmission tariffs via state action. In Situation 2, state municipalization law governs. In Situation 3, the state has authorized retail wheeling by statute or regulation, or both. Notwithstanding the need for state authorization in both cases, the majority decides that the Commission should be the ''primary forum'' in Situation 2, but that a much more narrow approach to retail stranded costs in Situation 3.[7] The more aggressive ''primary forum'' approach to municipalization is predicated on the view that any strandings are a result of an inducement (*i.e.*, market options) created by this Commission's Open Access Rule. Yet, since both wholesale transmission customers and retail transmission customers are ''eligible customers'' under the tariffs required by this Rule, if the Rule induces the stranding of retail power costs in one situation, it obviously does it in both.

As commenters have noted, the relationship between FERC-regulated transmission service and retail power customers is generally the same in both Situations 2 and 3.[8] The similarity runs first to the actions that actually cause costs to be stranded. While it is true that retail wheeling will only occur pursuant to state legislative or regulatory action, it is also true that a retail customer can only convert to wholesale status (*e.g.*, municipalize) pursuant to state law. This process sometimes may occur in the absence of regulatory or other oversight (*e.g.*, municipalization under pre-established statutory scheme), or with direct and immediate review and approval. The current evidence reflects active state commission oversight, typically. In this latter case, there is even less reason to distinguish between these Situations.

The majority implicitly seeks to delimit the area of appropriate state authority over stranded costs according to whether the state acts directly and by current enactments to authorize retail wheeling, on one hand, or less directly through established state municipalization laws, on the other.

[7] The policy adopted with respect to Situation 3 is that the Commission would only be a forum for hearing stranded costs issues in the narrow circumstance where ''the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.'' The majority fails to address what would happen if a legislature addresses the issue of stranded costs directly without delegating the task to a state regulatory authority. I would hope that the Commission would not set itself up for confrontation with a state legislature and I would have preferred that to also exclude those circumstances ''where the state otherwise addresses the issue'' from the circumstances in which the Commission would act in Situation 3.

[8] This argument is made both by commenters arguing that the Commission has no jurisdiction over stranded costs in Situation 2 or 3 (California Public Utilities Commission Initial Comments at 7) and by commenters arguing that the Commission should assert primary jurisdiction over stranded costs in both Situations (*see e.g.*, Edison Electric Institute Initial Comments at IV–13; Coalition For Economic Competition Initial Comments at 22; Utilities For An Improved Transition Initial Comments at 16–26).

However, costs could be stranded under state law by either action. Under the former scenario, however, a state is presumed to be more willing and capable of dealing with stranded costs. Under the latter, it is presupposed to be less interested. This distinction is specious.

A second similarity pertains to the jurisdictional status of transmission service. The Commission has been clear and consistent that the FPA gives the Commission exclusive jurisdiction over interstate transmission service, regardless of whether the customer is a wholesale or a retail wheeling customer. It is this authority upon which we rely to claim jurisdiction over transmission assets and related costs originally incurred to provide customers at the retail level with bundled service. New wheeling customers in both Situations 2 and 3 will take service under FERC open access tariffs. There are identical cost-causational facts in Situations 2 and 3, yet the majority adopts very different outcomes in each case under the Final Rule.

D. The ''Primary Forum'' Approach is More Subject to Legal Challenge

In my view, our disagreement involves more than a policy choice. The majority's chosen approach clearly makes our stranded cost recovery approach more vulnerable to a legal challenge. The cost recovery scheme which would result from the majority's approach will render a FERC-ordered transmission surcharge to recover retail stranded costs susceptible to legal challenge on the basis that it is anti-competitive and unduly discriminatory. The ''primary forum'' approach imposes upon a retail-turned-wholesale customer something akin to double jeopardy. In other words, a departing customer might have to pay both an exit fee for the retail costs which the state commission finds it has stranded and, in addition, an entry fee for wholesale access in the amount of the additional retail stranded costs which FERC determines are inadequately covered by state proceedings.

This, in my view, makes the Final Rule more susceptible to challenges that FERC's transmission surcharge is anti-competitive. *E.g., Cajun Electric Power Cooperative, Inc.* v. *FERC,* 28 F.3d 173 (D.C. Cir. 1994). The second-guessing of states inherent in the ''primary forum'' approach makes any arguments that stranded cost recovery is anti-competitive more difficult to overcome than if the stranded costs resulted from wholesale customers simply changing wholesale suppliers. This is because, unlike wholesale-to-wholesale strandings, the Commission cannot plausibly argue that the costs incurred were originally addressed in the context of its own rate decisions or were previously part of its responsibility for administering wholesale service obligations.

I am strongly persuaded that the Commission would be on much stronger legal ground if we were to treat state authority over stranded costs with the same deference in the municipalization or ''retail-turned-wholesale'' situation in the same manner as the Final Rule prescribes for situations where retail wheeling occurs. In the latter case, the Commission ought to provide a forum where neither the state legislature nor the state commission attempts to address this important transition issue.

James J. Hoecker,

Commissioner.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

[Docket No. RM95–8–000; Docket No. RM94–7–001]

Issued April 24, 1996.

MASSEY, Commissioner, *dissenting in part:*

I support all of the provisions of this rule save one, the provision on stranded costs arising from retail competition and from municipalization. When the Commission issued the Notice of Proposed Rulemaking, I stated that the Commission should treat stranded costs arising from retail competition and municipalizations similarly, as follows:

For either retail competition or municipalization, when the state commission has authority to address the issue, and uses such authority to decide the recoverability of the stranded costs, the state's decision should not be second-guessed by this Commission. However, when a state commission does not have the authority to decide the recoverability of stranded costs, or has authority but does not use it, this Commission should act on requests for stranded cost recovery.

My approach would assure utilities of getting a decision on the merits of their claim. Costs would not be stranded for lack of a regulatory decision. At the same time, this Commission would allow states to make decisions, when they have authority, on issues of critical concern to their local utilities and ratepayers. Only if states lack, or fail to use, such authority would this Commission step in to assure the utility of receiving a decision on the merits.

For the reasons I stated then, I still disagree with the rule's approach to stranded costs arising from retail competition or municipalization. In all other respects, I support this rule.

William L. Massey,

Commissioner.

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