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.[FN221] 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 ***21563** 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. [FN222] 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. [FN223] 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.[FN224] 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.[FN225]

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.[FN226]

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.[FN227]

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 ***21564** interpretation of the legislative history advanced by some commenters.[FN228]

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.[FN229] 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.[FN230])

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.[FN231]

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."[FN232] 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.[FN233]

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."[FN234]

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.[FN235]

***21565** 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."[FN236] 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.[FN237]

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.[FN238]

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.[FN239] 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.[FN240] 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.[FN241] 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."[FN242]

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 ***21566** utilities to provide non-discriminatory open access transmission.[FN243]

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.[FN244] 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."[FN245]

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.[FN246] 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).[FN247]

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.[FN248] 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.[FN249] 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.[FN250] 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."[FN251]

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."[FN252]

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.[FN253] According to EEI, the Commission cannot find, without an adjudicatory hearing, that the rates on file are unlawful and order replacement rates.[FN254] 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.[FN255]

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.

***21567** 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.[FN256]

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.

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.[FN257] 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." [FN258]

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 ***21568** 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.[FN259]

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.[FN260] 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.[FN261] 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.[FN262] 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.[FN263]

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. [FN264] 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, ***21569** and power marketers.[FN265] 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.[FN266]

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.[FN267] 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.[FN268] 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.[FN269]

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."[FN270] 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."[FN271] 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. * * *"[FN272]

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.'"[FN273]

NE Public Power District argues that sections 211 and 212 of the FPA appear clearly to contemplate a case-by-case approach.[FN274] 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 ***21570** 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.[FN275] 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.[FN276]

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.[FN277] Such legislative history provides no insight into the meaning of a statute and is given little or no weight by the courts.[FN278]

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.[FN279] 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.[FN280]

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.[FN281]

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."[FN282]

***21571 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.[FN283]

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).[FN284]

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.[FN285] In addition, we have also found that cooperatives and marketers are electric utilities as defined in the FPA.[FN286] 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.[FN287] 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.[FN288] 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,[FN289] 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 ***21572** 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.[FN290] 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.[FN291]

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.).[FN292] 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.[FN293] 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.[FN294] 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.[FN295] 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 *21573 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.[FN296] 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.[FN297]

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.[FN298]

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.[FN299] 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.[FN300] 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).[FN301] 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.[FN302] 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.[FN303]

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.[FN304] 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 ***21574** 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.[FN305]

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.[FN306]

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.[FN307] 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.[FN308] 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 ***21575** least as long as that offered by another potential customer.[FN309]

6. Capacity Reassignment

In the NOPR, the Commission proposed that a tariff must explicitly permit reassignment of firm service entitlements.[FN310] 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.[FN311] 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.[FN312] 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.[FN313] 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.[FN314] 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.[FN315] 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.[FN316] 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.[FN317] 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.[FN318] 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.[FN319] 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.[FN320] Another group of commenters believes that the original customer should be relieved of financial responsibility, at least under certain circumstances.[FN321] For ***21576** 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[FN322] to any eligible customer.[FN323] 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.[FN324] 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.[FN325]

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.[FN326]

Several utilities assert that the existing reporting requirements are sufficient to support the comparability requirements of the proposed rule, with some modifications.[FN327] They note that the Commission's audit authority and complaint process will help enforce comparability requirements.[FN328] 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 *21577 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,[FN329] to be posted on an OASIS.[FN330] x

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.[FN331]

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.[FN332]

Various state commissions question the workability and desirability of a functional test to determine the dividing line between retail transmission and local distribution.[FN333] 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.[FN334] 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.[FN335] 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.[FN336]

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.[FN337] 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 ***21578** 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.[FN338]

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.[FN339]

Comments

A number of commenters argue that utilities should be required to take all of the transmission for their own use under their tariff.[FN340] 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).[FN341] 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.[FN342] 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 multi-lateral 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.[FN343] 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.[FN344]

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).[FN345]

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 ***21579** 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.[FN346]

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.[FN347] 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.[FN348]

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 ***21580** 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.[FN349]

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,[FN350] 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.[FN351]

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.[FN352] 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 ***21581** 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.[FN353] 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.[FN354] It cannot be provided by a distant supplier.[FN355]

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.[FN356] 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 ***21582** 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.[FN357]

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.[FN358]

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.[FN359]

(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." [FN360]

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.[FN361] 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.[FN362]

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 ***21583** 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.[FN363] 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.[FN364] 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.[FN365] 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.[FN366] 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 ***21584** 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.[FN367] 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.[FN368]

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.

***21585** 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.[FN369]

Comments

Several commenters[FN370] 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.[FN371] 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.[FN372] 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).[FN373] Numerous commenters indicate that load following (now called Regulation and Frequency Response Service) generally is provided only by a control area operator.[FN374]

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.[FN375] 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.[FN376] 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.[FN377] NRECA and TDU Systems also state that many cooperatives and transmission ***21586** 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.[FN378] 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.[FN379] 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.[FN380]

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.[FN381] 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.[FN382] 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.[FN383] 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 ***21587** 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.[FN384] 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.[FN385] 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.[FN386]

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.[FN387] 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 ***21588** 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.[FN388]

(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.[FN389] 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.[FN390] Other commenters argue that scheduling and dispatch service, for similar reasons, should be bundled with basic transmission service.[FN391]

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.[FN392]

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.[FN393] 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 ***21589** 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.[FN394] 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.[FN395] 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.[FN396] Other commenters, including many IOUs, oppose reassignment because they believe it is impractical.[FN397] 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.[FN398] 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.[FN399]

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.[FN400] 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.[FN401] 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 ***21590** 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,[FN402] 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 ***21591** 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. [FN403]

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.[FN404]

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.[FN405] 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 ***21592** 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.[FN406] 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,[FN407] reliability, [FN408] and resource efficiency gains[FN409] 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.[FN410] Other commenters recommend that the Commission clarify that its policy on unbundling applies to all new transactions, whether pursuant to new or existing agreements.[FN411] 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.

***21593** 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.[FN412] 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.[FN413]

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.[FN414] 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.[FN415] 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.[FN416] 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 ***21594** accomplishing comparable access.[FN417] 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 ***21595** 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).[FN418]

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."[FN419] 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.[FN420] 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.[FN421]

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,[FN422] 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.[FN423]

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.[FN424] 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 ***21596** recognize that they could perform a useful role in a restructured industry.

Because an ISO will be a public utility subject to our jurisdiction,[FN425] 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 ***21597** 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). [FN426]

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.[FN427] 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.[FN428]

Subsequently, in a June 28, 1995 order, we encouraged public utilities to file open access transmission tariffs as soon as possible.[FN429] 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.[FN430] 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.[FN431] 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, ***21598** 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.[FN432]

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.[FN433]

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,[FN434] 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.[FN435] 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.[FN436] 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.[FN437]

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 ***21599** that consist predominantly of hydro generation.[FN438]

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.[FN439] 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.[FN440] 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.[FN441] 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,[FN442] 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.[FN443] 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 ***21600** 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[FN444] 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[FN445] 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.[FN446]

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 ***21601** "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.[FN447] We concluded that a public utility is entitled to full compensation for all "legitimate" and "verifiable" costs it incurs to provide firm transmission service.[FN448] 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.[FN449]

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.

(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 ***21602** 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.[FN450] 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.

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.

***21603 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.[FN451]

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.[FN452] 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.[FN453] 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.[FN454] 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 ***21604** 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.[FN455]

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.[FN456]

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 ***21605** 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.[FN457]

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 ***21606** priority of customers to obtain non-firm transmission capacity.[FN458] 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. [FN459]

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.[FN460] 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[FN461] 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. [FN462] 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 ***21607** 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. [FN463] 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..[FN464] 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.[FN465] 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).[FN466] 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 ***21608** 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.[FN467] 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,[FN468] 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.[FN469]

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.

***21609 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.[FN470]

NIEP believes the eligibility provision should include all entities that not only generate power themselves, but also purchase power generated by others for ***21610** 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.[FN471] 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.

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.[FN472] 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.[FN473]

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.[FN474] Sierra states that specific legislation by Congress 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.[FN475]

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.[FN476] 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.[FN477] 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 ***21611** 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.[FN478]

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.[FN479] 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.[FN480] LPPC asks that the reciprocity provision be dropped or changed to recognize these differences.[FN481] 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.[FN482]

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.[FN483] 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.[FN484]

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 *21612 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).[FN485] 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.

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.[FN486]

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,[FN487] the Commission does not have jurisdiction over cooperatives that have REA/RUS loans.[FN488] 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.[FN489] RUS notes that while the Energy Policy Act expanded the Commission's authority to order transmission access, it did not ***21613** 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.'"[FN490]

Various rural electric cooperatives state that the Commission must recognize that consumer-owned electric utilities are very different from investor-owned utilities.[FN491] 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.[FN492] 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."[FN493] 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- ***21614** 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.[FN494] 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.[FN495] 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" [FN496] or by financing facilities with "local furnishing" bonds.[FN497] 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.[FN498] 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.[FN499] 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.[FN500]

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." [FN501] San Diego G&E has included in its existing transmission tariff a provision ***21615** 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).[FN502] 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.[FN503]

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 ***21616** 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,[FN504] 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 ***21617** 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.[FN505] 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.[FN506]

Those commenters that oppose the two-stage implementation process do so for a variety of reasons.[FN507] 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.[FN508] 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 ***21618** 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"[FN509] 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.[FN510] 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).[FN511]

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 ***21619** 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.[FN512] 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).[FN513]

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.[FN514] 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[FN515] 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.[FN516] 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:

***21620** (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.[FN517]

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.[FN518]

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.[FN519]

Comments

Several commenters support the Commission's proposed jurisdictional demarcation.[FN520] 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.[FN521] 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." [FN522] 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 ***21621** 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.[FN523] 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.[FN524] 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.[FN525] 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.[FN526]

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.

***21622** 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).[FN527]

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.[FN528]

NV Com further explains that the determination of what is a network event would require a case-by-case examination. *21623 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."[FN529] 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."[FN530] 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."[FN531] 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."[FN532] 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.([FN533])

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,[FN534] 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 ***21624** 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.[FN535] 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.[FN536]

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.[FN537]

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.[FN538]

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?

***21625** 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.[FN539]

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.[FN540] 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.[FN541] 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